FEDERAL ENERGY REGULATORY COMMISSION

ASSESSMENT OF

Demand Response & Advanced Metering

STAFF REPORT

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Demand Response and Advanced Metering

Staff Report

Federal Energy Regulatory Commission

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Executive Summary

Both advanced metering penetration and potential peak load reduction from demand response have increased since 2006. Significant activity to promote demand response or to remove barriers to demand response occurred at the state, federal, and company level.

Advanced Metering

The results of the 2008 FERC Demand Response and Advanced Metering Survey (2008 FERC Survey) indicate advanced metering penetration (*i.e.*, the ratio of advanced meters to all installed meters) has reached about 4.7 percent for the United States. This is a significant increase from 2006, when advanced metering penetration was less than one percent.

Market penetration of advanced metering increased substantially in nearly all regions since 2006. Peninsular Florida had the largest increase, from less than one percent advanced metering penetration in 2006 to 10.4 percent in 2008.

Market penetration differs by type of organization. While cooperatives, municipal utilities, investor-owned utilities, public utility districts, and federal utilities all show increases since 2006, the high penetration levels achieved by cooperatives in the past two years is particularly impressive. Cooperatives' advanced metering penetration increased from 3.8 percent in 2006 to 16.4 percent in 2008.

Demand Response Programs

The 2008 FERC Survey indicates that about eight percent of customers in the United States are in some kind of demand response program. There have also been large increases in customer enrollment and the number of entities that offer demand response programs; for example, the number of entities offering real-time pricing increased significantly since 2006.

The potential demand response resource contribution from all U.S. demand response programs is estimated to be close to 41,000 MW, or about 5.8 percent of U.S. peak demands. This represents an increase of about 3,400 MW from the 2006 estimate. The regions of the country with the largest demand response resource contributions as a percent of the national total are the Mid-Atlantic, Midwestern, and Southeastern United States.

Demand Response Developments

In the past year, several states such as Colorado, Maryland, and Ohio promoted demand response through legislation and utility regulation. Other states, such as Alabama and California, approved time-based rates for customers under their jurisdiction. In addition, multi-state groups spanning the country from the Mid-Atlantic to the Midwest and Pacific Northwest continue to coordinate across jurisdictions to enhance demand response through research, education, and planning.

Numerous utilities and demand response aggregators have taken action to expand their retail demand response programs. Utilities across the nation are expanding demand-side management programs in response to high load growth and the increasing cost and time required to bring new generation into service. In addition, third-party demand response aggregators have expanded efforts to include customers who would otherwise be unable to participate in demand response programs.

The Federal Energy Regulatory Commission (FERC) is working to ensure the comparable treatment of demand response resources in wholesale markets. For example, in October 2008, the FERC issued a final rule on competition in organized markets that, in part, removes several barriers to demand response participation in the organized wholesale markets. Among other provisions, it requires all regional transmission organizations (RTOs) and independent system operators (ISOs) under FERC's jurisdiction to allow comparable treatment of demand response resources in ancillary services markets, eliminate certain charges to buyers for reducing load during a system emergency, permit demand response aggregators to bid demand response on behalf of retail customers directly into the organized energy market, and change the pricing rules as necessary to allow the market price of power to reflect the value of lost load during an operating reserve shortage.

Demand response resources played a critical role in ensuring the reliability of the electricity grid during periods of severe strain in the past year. Demand response resources helped meet peak load in California, the Mid-Atlantic, and New York; helped respond to other system emergencies, including addressing sudden changes in generation output in Texas; and participated in capacity markets in the PJM Interconnection and ISO-New England.

Regulatory Barriers

States and the federal government have also acted to remove regulatory barriers limiting customer participation in demand response, peak reduction, and critical period pricing programs. Ten states have adopted policies that decouple changes in utility revenue with changes in sales volume. The National Association of Regulatory Utility Commissioners and FERC established two collaborative efforts to address issues crucial to the effective implementation of demand response and the related topic of smart grids. There is growing attention to demand response measurement and verification, with many entities such as the FERC, RTOs and ISOs, the North American Energy Standards Board, state electric regulatory commissions, and several regional research entities all examining how to develop measurement and verification protocols or standards that accurately measure load reductions.

However, many obstacles remain. One such barrier is the limited number of retail customers on time-based rates. Another is restrictions on customer access to meter data, making information retrieval for customers and their independent aggregators of retail customers time consuming and expensive. Timely access to customer meter data allows aggregators to assess the demand reductions achieved by their customers. There is also an increased need to accurately measure load reductions so as to ensure confidence in the ability of demand response providers to actually provide demand response service when needed. Another barrier is the scale of financial investment required to deploy enabling technologies during an economic downturn. Finally, the availability of only a limited variety of demand response programs that accommodate the operating needs of potential demand response providers may also be a barrier. Government and industry have begun programs to address most of these barriers, but significant work remains to be done.

Recommendations

Staff recommends that the Commission continue to make demand response a priority. Specific recommendations include: (1) continue current coordination with NARUC on finding demand response solutions, with a focus on aligning retail demand response programs and time-based rates with wholesale market designs; (2) continue exploring how to remove barriers to the comparable treatment of demand response resources in wholesale markets; (3) coordinate the Commission's National Assessment of Demand Response and National Action Plan for Demand Response efforts required by Congress in the Energy Independence and Security Act of 2007 with the ongoing annual demand response reporting required by the Energy Policy Act of 2005 to ensure effective use of Commission resources; (4) support the efforts of organizations such as NERC, NAESB, and EIA to develop practical means to measure, verify, forecast, and track demand response; and (5) explore possible linkages among demand response, energy efficiency, and smart grid programs. As required by law, in 2009 the Commission's National Assessment of Demand Response will contain additional recommendations for achieving the nation's demand response potential.

Table of Contents

Chapter I. Introduction

This report on demand response and advanced metering fulfills a requirement of the Energy Policy Act of 2005 (EPAct 2005) section 1252(e)(3)[1] that requires the Federal Energy Regulatory Commission (FERC or Commission) to prepare and publish an annual report, by appropriate region, that assesses electricity 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.

Prior Reports in This Series

The Commission staff published its first report, *Assessment of Demand Response and Advanced Metering* (2006 FERC Demand Response Report), in August 2006[2] and its second report in September 2007.[3] The 2006 report was comprehensive and reported on a first-of-its-kind survey of demand response and advanced metering. In 2007, the Commission staff published a second report, emphasizing results, industry activities, and regulatory actions taken since 2006. That report noted that FERC staff would conduct, analyze, and report on the results of a comprehensive nationwide survey every other year, with intervening years' reports focusing on updates based on publicly available information and discussions with market participants and industry experts. Staggering the reporting in this way allows the FERC staff to provide a more informed analysis in each bi-yearly survey-based report while still reporting on the advances in demand response on an annual basis.

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[1] 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.

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

[3] FERC, *Assessment of Demand Response & Advanced Metering*: *Staff Report*, September 2007, *available at* http://www.ferc.gov/industries/electric/indus-act/demand-response.asp.

Preparation of This Year's Report

In preparing this report, Commission staff undertook several activities, the most significant of which was the preparation and release of the Demand Response and Advanced Metering Survey (2008 FERC Survey), and data cleaning and analysis of the survey responses. Staff also gathered additional information on demand response and advanced metering by convening and participating in a technical conference held in support of the Commission's rulemaking on wholesale competition in organized markets. That conference focused on several demand response issues including: barriers to comparable treatment of demand response; solutions to eliminate such barriers; and the need for and the ability to standardize terms, practices, rules and procedures associated with demand response. The record associated with this technical conference supported the development of this years' report.

Commission staff also reviewed the literature, interviewed key experts, and analyzed recent developments on advanced metering, demand response programs, and time-based rates. This review focused on activities since the 2007 FERC Demand Response Report.

Demand Response and Advanced Metering Survey

The 2008 FERC Survey was conducted in the first half of 2008 with the help of UtiliPoint International and requested: (a) general information about the respondent, including contact information, customer size, and electricity demand and consumption; (b) the number of advanced meters and their use; and (c) existing demand response and time-based rate programs, including their current level of resource contribution. The 2008 FERC Survey used largely the same survey structure, forms, and questions as the 2006 survey. Both surveys had two sections, one for Advanced Metering Infrastructure (AMI) and one for demand response. Several questions used in 2006 were revised for clarity.

Responses to the survey were requested from 3,407 entities from all 50 states representing all aspects of the electricity delivery industry: investor-owned utilities, municipal utilities, rural electric cooperatives, power marketers, state and federal agencies, and demand response providers.[4]

More than 2,094 entities responded to at least one section of the 2008 FERC Survey (a response rate of over 61 percent), an increase from the 2006 FERC Survey response rate of 55 percent. More respondents completed the advanced metering section of the survey (60 percent) than the demand response section (55 percent).

Table I-1. 2008 Survey response rates: demand response and advanced metering

Survey Section	Number of Responses	Response Rate
Advanced Metering	2,035	60%
Demand Response	1,889	55%

Information gathered through the survey serves as the basis for this report's data on the penetration[5] of advanced metering, the information on existing demand response and time-based rate programs, and

[4] Appendix D includes detailed information on the survey and sample design. Appendix E lists the respondents to the survey.

estimates of demand response resource contribution. In addition, the results of the 2008 and 2006 FERC Surveys provide the beginnings of time series data on advanced metering penetration and level of demand response in the United States, which will allow us to assess trends in the future.

Report Organization

The report begins with this introduction, which describes the report structure. The following chapters provide the information requested by EPAct 2005 section 1252(e)(3).

Chapter 2 presents the survey results on the penetration of advanced metering nationally, regionally, by type of utility, customer class, and by state. This chapter also discusses the key new developments, issues, and trends in the deployment and adoption of advanced metering

Chapter 3 briefly introduces each type of demand response program and the various time-based rates. It presents the survey results on demand response programs, including time-based rate programs, and gives the regional and national distribution of these programs, as measured by the number of enrolled customers reported in the 2008 FERC Survey. This chapter also uses the 2008 FERC Survey data to estimate the size of the demand response resource in the United States today.

Chapter 4 reviews demand response trends and developments. This chapter summarizes activity on demand response at the national and state level, and identifies several key trends in demand response implementation policy. In addition, this chapter reviews Commission demand response activities and steps that have been taken to ensure comparable treatment of demand response in regional transmission planning.

Chapter 5 summarizes and analyzes the barriers to demand response identified from various sources.

This report also contains seven appendices that provide reference material and additional detail on the 2008 FERC Survey and survey respondents. **Appendix A** lists the statutory language in section 1252 of EPAct 2005. **Appendix B** lists the acronyms used in this report. **Appendix C** contains a glossary of the key terms used in this report and the 2008 survey. **Appendix D** presents additional detail on the 2008 FERC Survey and documents survey response rates. **Appendix E** lists the respondents to the 2008 FERC Survey. **Appendix F** lists the entities that indicate that they operate demand response programs in their responses to the 2008 survey. **Appendix G** provides data tables associated with each of the figures in this report.

Regions in This Report

For the purposes of reporting the results of the assessment of demand response and advanced metering by region, this report uses the U.S. portions of the eight North American Electric Reliability Council (NERC) regions and an “Other” category. These NERC reliability regions include:

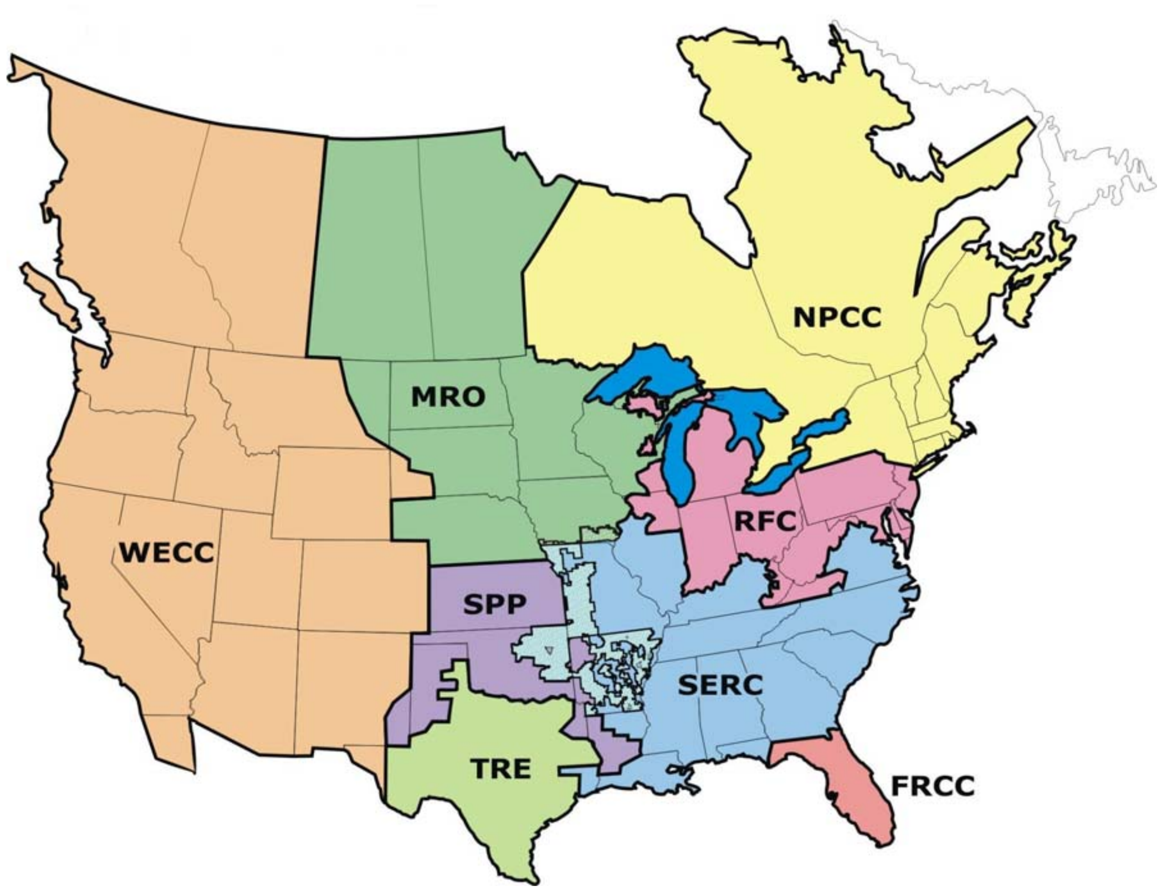
- Florida Reliability Coordinating Council (FRCC)
- Midwest Reliability Organization (MRO)
- Northeast Power Coordinating Council (NPCC)
- Reliability*First* Corporation (RFC)

[5] Penetration, for the purposes of this report, refers to the ratio of advanced meters to all installed meters.

- SERC Reliability Corporation (SERC)
- Southwest Power Pool Regional Entity (SPP)
- Texas Regional Entity[6] (TRE), and
- Western Electricity Coordinating Council (WECC)

Figure I-1 displays the configuration of these regions as of September 2008. Survey results for Alaska and Hawaii are presented as their own region in Chapter II but are included with Other in Chapter III because of the minimal amount of demand response reported for these two states.

Figure I-1: NERC region map



[6] The Texas Regional Entity is a functionally independent division of Electric Reliability Council of Texas (ERCOT). The Texas Regional Entity performs the regional entity functions described in EPAct 2005 for the ERCOT region. For the purposes of this report, "ERCOT" will be used to describe this region.

Chapter II. Advanced Metering Infrastructure

This chapter addresses the first area that Congress, in EPAct 2005 section 1252(e)(3), directed the Commission to report on:

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

The information presented on advanced metering penetration is based on the 2008 FERC Survey,[7] and for comparison purposes the 2006 FERC Survey results. An update on the developments, challenges, and issues for advanced metering since Staff's 2007 FERC Demand Response Report is also provided.

The 2008 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. Results show that advanced metering penetration has grown significantly since the 2006 FERC Survey, increasing nationally from less than one percent in 2006 to 4.7 percent in 2008.

This chapter also reports that utilities continued to announce new advanced metering initiatives, award new contracts for the purchase of advanced metering systems, and deploy advanced metering systems in 2007 and 2008. State policies that promote advanced metering and utilities' ability to demonstrate a favorable business case are two of the key drivers of advanced metering adoption.

This chapter is organized into five sections:

- Definition and use of advanced metering,
- Advanced metering market penetration from the 2008 FERC Survey,
- Developments in advanced metering, and
- Challenges and issues for advanced metering.

Definition of Advanced Metering

As in past reports, advanced metering is defined as a metering system that records customer consumption (and possibly other parameters) hourly or more frequently and provides for daily or more frequent transmittal of measurements over a communication network to a central collection point.[8] The terms advanced metering and advanced metering infrastructure (or AMI) are used interchangeably throughout this report.

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[7] See Appendix D for a description of the 2008 FERC Survey.

[8] 2006 FERC Demand Response Report, 17. Advanced meters are typically, if not exclusively, based on digital electronic technology.

Advanced Metering Market Penetration from 2008 FERC Survey

This section presents and analyzes the results from the 2008 FERC Survey.

2008 FERC Survey Design

The 2008 FERC Survey was based on the 2006 FERC Survey and contained an almost identical set of questions. Like the 2006 FERC Survey, the 2008 FERC Survey asked respondents to identify the total number of meters by customer class that their entity owns or operates, how many of their meters are advanced meters, and how they are using advanced metering, *e.g.*, enhanced customer service and outage detection and restoration. The 2008 survey recipients were asked to distinguish between advanced meters that provide readings at intervals of 15 minutes or less, and those which provide readings at intervals from more than 15 minutes to an hour.[9] Survey recipients were also provided with an enhanced list of advanced metering features from which to select in describing how their entity uses its advanced metering system(s).

Survey Findings

1) Overall Results

Although the response rate for the advanced metering section of the 2008 FERC Survey was 60 percent, the total number of meters (of all types) reported by survey respondents accounts for 91 percent of all currently installed electricity meters in the United States. Since the survey respondents account for most of the installed electric meters in the United States, Commission staff developed advanced metering penetration estimates by extrapolating the survey's advanced metering penetration to the entire population of installed meters.

The 2008 FERC Survey results show advanced metering penetration in the United States is at 4.7 percent, compared to less than one percent in 2006. (See Figure II-1 below.)

The 2008 FERC Survey asked respondents to identify meters *being used* for advanced metering. However, unlike the 2006 FERC Survey, the 2008 FERC Survey does not ask respondents to also identify meters *capable of being used for* advanced metering. Improper analysis in distinguishing between meters *being used* and those *capable of being used* for advanced metering led to the reporting of erroneous results in 2006.[10] Corrected 2006 findings show entities reported 8.4 million meters as *capable of being used* and 947,224 as *being used* for advanced metering. In 2008, by comparison, entities report having deployed 6.7 million advanced meters that are being used for advanced metering. Table II-1 shows the number of meters reported as *capable of being used* for advanced meters for 2006 and those *being used* for advanced meters for both 2006 and 2008.

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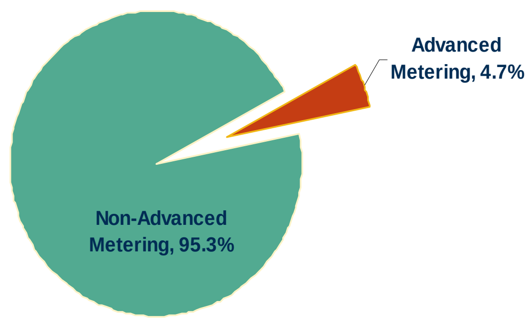
[9] Commission staff's definition for advanced metering also requires metering data be uploaded to the utility's back end computer systems at least daily. In order to focus on this definition of advanced metering, Commission staff did not ask for information about other collection and measurement interval lengths that had been collected in the 2006 FERC Survey.

[10] The 2006 FERC Survey as originally published had indicated that the overall penetration of advanced metering in the United States was 5.9 percent. It was later discovered that an error had been made in analysis performed under contract to the Commission. The correct penetration levels for 2006 are 0.7 percent for metering *being used* as advanced metering and 5.9 percent for *metering capable of being used* for advanced metering.

Figure II-1. United States 2008 penetration of advanced metering



Source: 2008 FERC Survey

Table II-1. AMI meters: AMI-*capable* meters versus AMI in actual use

	AMI-capable	Actually being used for AMI	Total customer meters (AMI-capable, actual AMI, and all other meters)
2006	8,398,455	947,224	141,994,039
2008	unavailable	6,733,151	144,385,392

Source: 2006 FERC Survey and 2008 FERC Survey

2) Participant Comments

Survey respondents in 2008 were given the opportunity to provide additional information about their entity's use of advanced metering. A number of respondents offered comments such as noting ongoing deployments, pilot programs, or plans for deploying advanced metering. Sample comments regarding ongoing deployments include:

- "We anticipate having 100 percent AMI deployment by the end of 2009."
- "We began installing AMI in 2008."
- "…in the process of implementing an Advanced Metering Infrastructure."

Other comments pertaining to plans to deploy advanced metering include:

- "We are currently investigating two-way AMI systems and hope to implement one later this year. It will eventually replace our one-way system used now."
- "We plan to begin deploying AMI system-wide in 2009 with deployment completed by the end of 2011."

- "Currently have an AMI System in pilot testing with xxx meters (not billing). Planning to implement AMI System beginning in 2009 and completing in 2012."

If these sample comments are truly representative of future activity and interest among utilities, the penetration of advanced metering should continue to increase in future years.

3) Breakdown of Advanced Metering Penetration Results

Survey results can be broken out in various ways, including by customer class, by region, by customer class and region together, by state, and by size of entity.

A break out of the national results by customer class shows that market growth in advanced metering is not confined to residential customers. Residential and nonresidential (including industrial, commercial, transportation, and "other") customer meters are being deployed at similar rates. Advanced metering penetration for nonresidential customers increased from 1.0 to 4.2 percent from 2006 to 2008, and increased for residential customers from 0.6 to 4.7 percent.[11]

Figure II-2 shows a break out of advanced metering penetration by type of entity. Cooperatives, municipal entities, investor-owned utilities, public utility districts and federal utilities all show increases, with the number of installed advanced meters having increased by approximately 5.8 million from the 2006 to 2008 FERC Surveys. Cooperatives and investor-owned utilities together account for 5.4 million of those new advanced meters. Cooperatives deployed approximately 2.4 million advanced meters, accounting for 41 percent of the 5.8 million increase in advanced metering penetration since 2006. This deployment by cooperatives represents an increase of 360 percent from 3.8 percent penetration in 2006 to 16.4 percent in 2008. Over the same period, investor-owned utilities deployed approximately three million advanced meters, accounting for 46 percent of the 5.8 million total increase in advanced metering since the 2006 FERC Survey. Advanced metering penetration for investor-owned utilities shows an increase of 1,081 percent, from 0.2 percent penetration in 2006 to 2.7 percent in 2008. Advanced metering penetration for municipal entities shows an increase of 1,673 percent, increasing from 0.3 percent in 2006 with approximately 43,500 advanced meters to 4.9 percent in 2008 with 771,660 advanced meters. Public Utility Districts advanced metering penetration shows an increase of 2,988 percent from 0.1 percent with 2,491 advanced meters in 2006 to 2.2 percent with 76,929 advanced meters in 2008.[12]

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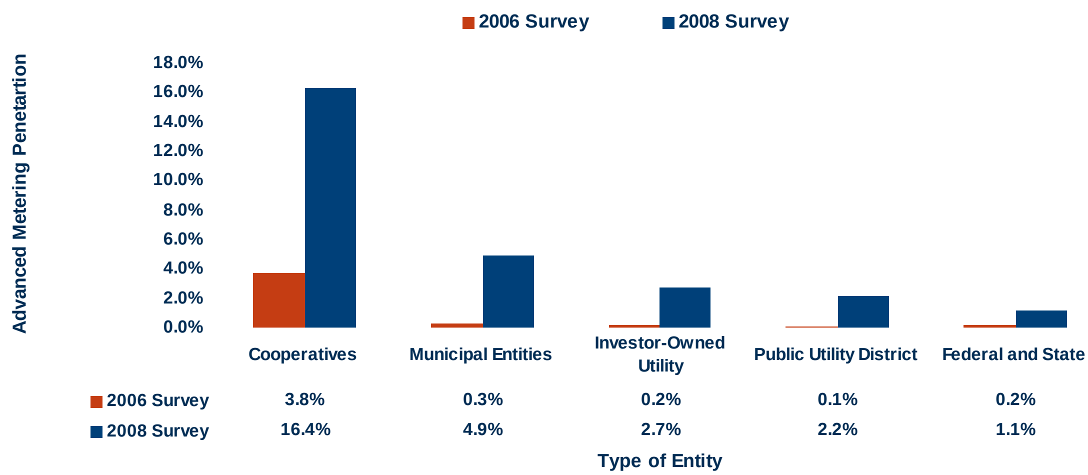
[11] In comparing the 2006 and 2008 survey responses, Commission staff distinguishes only between residential and nonresidential AMI penetration. This is because of inconsistencies between the two surveys in the way respondents identify various nonresidential customer classes. For example, one large utility reported no industrial meters in 2006, but in 2008 reports having over 5,000. The difference may be too great to explain as anything other than a change in classification of the meters between the two surveys. In the 2008 survey, many respondents state that they do not distinguish between commercial and industrial customers, and report them all as commercial customers. This problem also applies to the transportation customer class (*e.g.*, a rapid transit company that buys electric power) because some respondents classify meters for such customers "other" in 2006, but classify those same meters as "Transportation" customer meters in 2008. Further, some 2008 survey respondents note that they report all transportation customer meters as industrial customer meters. Such inconsistencies make it difficult to compare differences in advanced metering penetration between industrial, commercial, transportation and what the survey terms as "other" class customers.

[12] Power marketers/retailers are not shown on this chart. Reporting of total meters by these types of entities was found to be inaccurate.

Figure II-2. Penetration of advanced metering by type of entity



Source: 2006 FERC Survey and 2008 FERC Survey

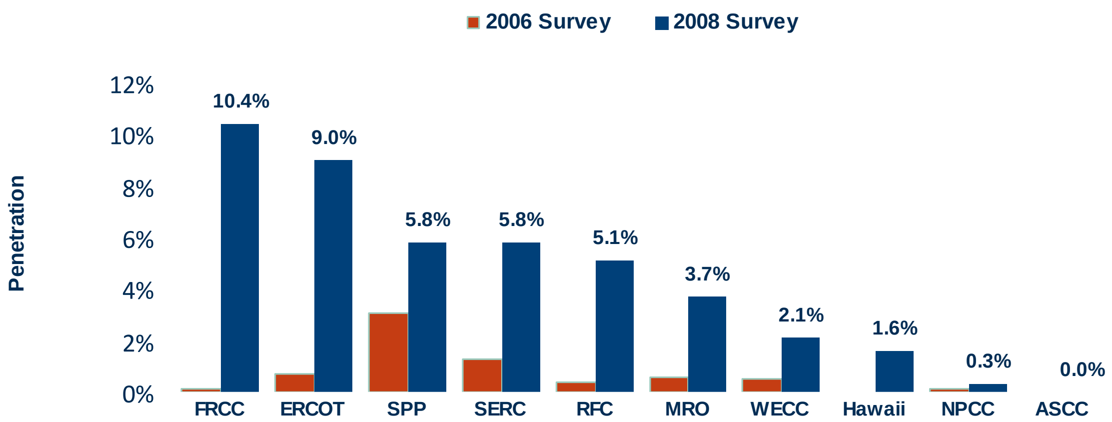
Figure II-3 shows increases in advanced metering penetration broken out according to NERC regional reliability councils regions (plus the Alaska Systems Coordinating Council (ASCC) and Hawaii).[13] The region with the highest penetration does not necessarily have the largest absolute number of meters. Increases in advanced metering penetration since 2006 are evident for almost all regions.

The Florida Reliability Coordinating Council (FRCC) and Electric Reliability Council of Texas, Inc. (ERCOT) show the greatest percentage increases since 2006 and the highest penetrations by region in 2008, 10.4 and 9.0 percent respectively. In the FRCC region, adoption of advanced metering by municipal utilities accounts for the largest increase in that region. The increase in ERCOT is primarily due to activity by investor-owned utilities and cooperatives. Advanced metering deployment by Oncor, a large investor-owned utility in Texas, accounts for 77 percent of the increase.

Advanced metering increases in SERC Reliability Corporation (SERC) and the Southwest Power Pool (SPP) stem mainly from cooperatives' adoption of AMI. The surge in advanced metering at Reliability*First* Corporation (RFC) is almost entirely attributable to PPL, a large investor-owned utility in Pennsylvania.

[13] The region in the figures and tables are the eight NERC regions, ASCC (Alaska), and Hawaii. See Chapter I for a map defining these regions. Although it is not a NERC region, Figure II-3 displays information for Hawaii.

Figure II-3. AMI penetration by region



	FRCC	ERCOT	SPP	SERC	RFC	MRO	WECC	Hawaii	NPCC	ASCC
2006 Survey	0.1%	0.7%	3.0%	1.2%	0.4%	0.6%	0.5%	0.0%	0.1%	0.0%
2008 Survey	10.4%	9.0%	5.8%	5.8%	5.1%	3.7%	2.1%	1.6%	0.3%	0.0%

Region

Source: 2006 FERC Survey and 2008 FERC Survey

Table II-2 provides a break out of the regional market penetration for residential and nonresidential customers. ERCOT has the highest penetration of advanced metering for nonresidential customers. The high penetration in the region is due to system-wide deployment of AMI by cooperative and municipal utilities and Oncor's installation of a large number of advanced meters for what it classifies as commercial and industrial customers.

FRCC has the highest advanced metering penetration of all regions for residential customers and has higher than average penetration for each customer class. Three utilities in FRCC account for a majority of advanced metering use in FRCC: JEA (the large municipal utility serving Jacksonville), Lee County Electric Cooperative (a large cooperative), and Florida Power and Light (a large investor-owned utility).

Table II-2. AMI penetration by region and customer class

	Overall AMI Penetration		Residential AMI Penetration		Nonresidential AMI Penetration	
Region	2006	2008	2006	2008	2006	2008
FRCC	0.1%	10.4%	0.1%	10.8%	0.5%	7.8%
ERCOT	0.7%	9.0%	0.7%	8.5%	0.7%	12.4%
SERC	1.2%	5.8%	1.3%	6.1%	1.0%	3.2%
SPP	3.0%	5.8%	3.3%	6.1%	1.8%	4.2%
RFC	0.4%	5.1%	0.3%	5.0%	0.8%	6.1%
MRO	0.6%	3.7%	0.5%	4.0%	1.1%	2.2%
WECC	0.5%	2.1%	0.3%	2.1%	1.5%	2.0%
Hawaii	0.0%	1.6%	0.0%	1.6%	0.1%	1.6%
NPCC	0.1%	0.3%	0.1%	0.3%	0.8%	1.0%
ASCC	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Overall Average	**0.7%**	**4.7%**	**0.6%**	**4.7%**	**1.0%**	**4.2%**

Source: 2006 FERC Survey and 2008 FERC Survey

Regions with higher than average penetrations for one or more of the major customer classes as defined by 2008 FERC Survey respondents include FRCC, ERCOT, SERC, SPP, and RFC for residential penetration, and FRCC, ERCOT, and RFC for nonresidential penetration.

Table II-3 shows advanced metering penetration by state for 2006 and 2008. For most states, penetration increased in the last two years. Survey results from 2006 show many states with essentially zero advanced meters. The FERC 2008 Survey shows that most states now have advanced metering penetration above zero. Pennsylvania had the largest increase in penetration between 2006 and 2008 FERC Surveys, moving from 0.3 percent to 23.9 percent over the two-year period. The increase in penetration for Pennsylvania is due to the installation of a full AMI system at PPL since the 2006 FERC Survey. North Dakota and South Dakota increased from zero percent to almost nine percent, due mostly to cooperatives in the state adopting advanced metering.

The 2008 FERC Survey findings show the five states with highest penetration of advanced metering are Pennsylvania, Idaho, Arkansas, North Dakota, and South Dakota. The source of the high penetration of advanced metering in Arkansas, North Dakota, and South Dakota is high levels of advanced metering deployment at cooperatives. The high penetrations in Pennsylvania and Idaho are due primarily to the advanced metering deployments of investor-owned utilities.

Table II-3 – Penetration of advanced metering by state in 2006 and 2008

	2006			2008		
State	AMI meters	Total meters	Penetration	AMI meters	Total meters	Penetration
Pennsylvania	18,200	6,053,110	0.3%	1,443,285	6,036,064	23.9%
Idaho	29,062	739,199	3.9%	105,933	769,963	13.8%
Arkansas	75,118	1,494,383	5.0%	168,466	1,488,124	11.3%
North Dakota	29	367,776	0.0%	33,336	375,473	8.9%
South Dakota	7	484,728	0.0%	41,191	475,477	8.7%
Oklahoma	60,273	2,024,592	3.0%	161,795	1,875,325	8.6%
Texas	28,200	10,195,134	0.3%	868,204	10,870,895	8.0%
Florida	8,479	9,679,565	0.1%	765,406	9,591,363	8.0%
Georgia	73,312	4,404,447	1.7%	342,772	4,537,717	7.6%
Missouri	8,986	3,087,821	0.3%	204,498	3,098,055	6.6%
Vermont	1	331,161	0.0%	20,755	375,202	5.5%
Alabama	89,702	2,738,519	3.3%	139,972	2,774,764	5.0%
Kentucky	27,501	2,225,485	1.2%	105,460	2,161,142	4.9%
South Carolina	19,655	2,007,339	1.0%	114,619	2,373,047	4.8%
Kansas	18,913	1,430,953	1.3%	61,423	1,426,832	4.3%
Wisconsin	19,882	2,983,075	0.7%	117,577	3,039,830	3.9%
Wyoming	0	272,033	0.0%	12,268	318,282	3.9%
Arizona	5,521	2,783,083	0.2%	96,727	2,810,224	3.4%
North Carolina	29,411	4,681,178	0.6%	143,093	4,771,479	3.0%
Iowa	110	1,591,985	0.0%	46,407	1,714,774	2.7%
Washington	477	3,061,233	0.0%	69,377	2,987,355	2.3%
New Mexico	1	875,393	0.0%	20,776	904,861	2.3%
Oregon	2,960	1,821,710	0.2%	39,797	1,890,423	2.1%
Louisiana	44	1,037,355	0.0%	44,103	2,186,249	2.0%
Indiana	13,137	3,217,359	0.4%	61,551	3,115,205	2.0%
Illinois	43,043	5,510,470	0.8%	112,410	5,701,533	2.0%
Tennessee	426	3,165,211	0.0%	60,385	3,160,551	1.9%
Colorado	39,274	2,263,873	1.7%	39,873	2,246,184	1.8%
Montana	162	529,135	0.0%	8,979	549,136	1.6%
Hawaii	45	465,314	0.0%	6,550	405,228	1.6%
Minnesota	11,780	2,537,414	0.5%	37,071	2,542,113	1.5%
Michigan	31,254	4,877,345	0.6%	73,948	5,311,570	1.4%
California	40,153	14,253,873	0.3%	170,896	14,595,958	1.2%
Nebraska	1,520	937,148	0.2%	8,630	970,774	0.9%
Nevada	17	1,193,873	0.0%	10,835	1,292,331	0.8%
Ohio	1,958	6,307,050	0.0%	28,042	5,544,353	0.5%
Connecticut	3,862	1,580,365	0.2%	5,838	1,600,768	0.4%
New Jersey	25,222	3,884,140	0.6%	9,866	3,900,716	0.3%
District of Columbia	0	809,412	0.0%	1,348	809,412	0.2%
New York	3,071	7,906,309	0.0%	12,778	7,811,335	0.2%
Virginia	5,016	3,412,011	0.1%	6,448	3,965,584	0.2%
Massachusetts	6,940	3,244,778	0.2%	3,907	3,077,679	0.1%
Maine	716	773,164	0.1%	426	780,748	0.1%
New Hampshire	306	759,514	0.0%	260	763,683	0.0%
Rhode Island	398	480,275	0.1%	148	480,135	0.0%
Alaska	6	305,949	0.0%	18	315,419	0.0%
Utah	1	1,036,605	0.0%	37	1,056,718	0.0%
West Virginia	17	1,234,035	0.0%	10	1,183,513	0.0%
Maryland	130	1,972,886	0.0%	8	1,938,948	0.0%
Mississippi	82	1,015,493	0.0%	3	1,454,275	0.0%
Delaware	16	421,331	0.0%	0	438,020	0.0%
Virgin Islands	0	53,628	0.0%	0	53,628	0.0%

Source: 2006 FERC Survey and 2008 FERC Survey

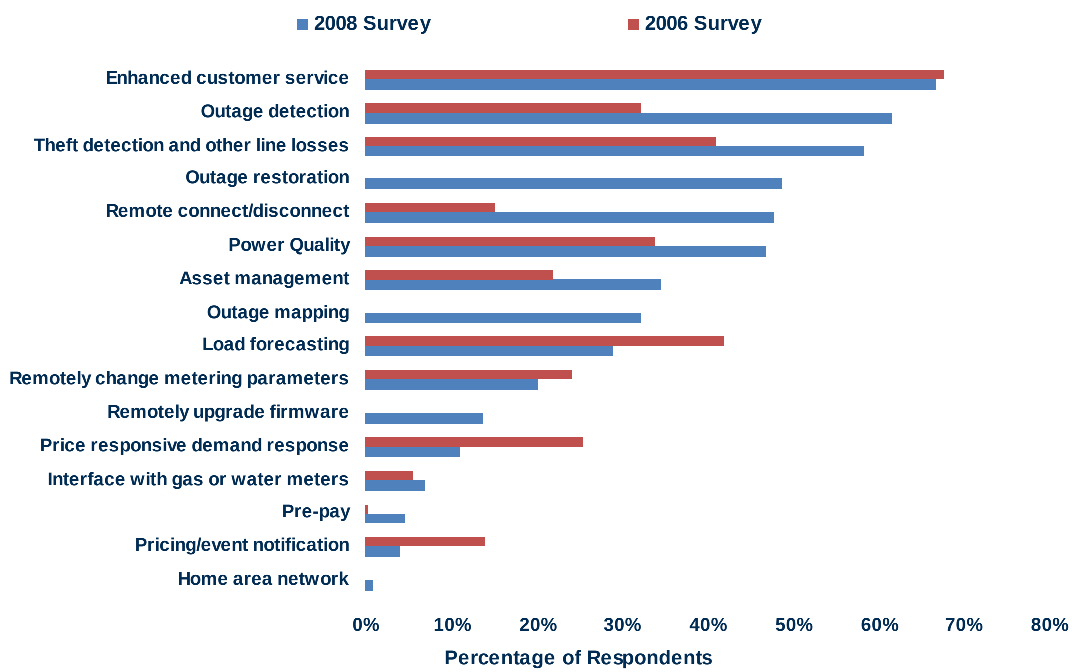
Notes: The number of meters is extrapolated to account for less than 100 percent response rate.

The number of installed meters in Table II-3 varies slightly between 2006 and 2008 in large part because of the variation in the number of meters reported by survey respondents, and also because of the method used to calculate the number of meters in a state. The number of meters in a state is calculated by adding to the direct survey responses an estimate of the number of meters for non-respondents. The number of meters for non-respondents is calculated from 2006 data for those that responded in 2006 but not 2008 and from EIA customer data otherwise. Commission staff did not attempt to reconcile the meter data to other data sources.

Uses of Advanced Metering

Similar to the 2006 FERC Survey, the 2008 FERC Survey asked respondents how their entities use advanced metering, beyond interval meter reading collection. Figure II-4 shows the results for 2006 and 2008. Respondents identify increased use of newer types of advanced metering functionality, especially the use of advanced metering to perform remote outage management and to remotely upgrade firmware on the advanced meters. Enhanced customer service is the most often cited use of advanced metering by respondents, as it was in 2006.

Figure II-4. Reported uses of advanced metering in 2006 and 2008



Source: 2006 FERC Survey and 2008 FERC Survey

As mentioned earlier, the 2008 FERC Survey included an enhanced list of advanced metering features for respondents' use in describing how their entity uses its advanced metering system(s). The list included outage restoration, outage mapping, remote upgrade of metering firmware, and use with home-area networks, none of which was included in the 2006 FERC Survey instrument.
In the 2008 survey results, outage detection was cited by 62 percent of respondents, 49 percent cite outage restoration and 32 percent cite outage mapping. This demonstrates the importance and value of these uses for utility operations.[14]

[14] *Outage detection* using advanced metering is still an emerging capability. Until recently, utilities have relied on calls from customers reporting outages. This results in some outages going undetected, especially at remote locations. Outage detection using advanced metering detects more outages and is much faster than relying on calls from customers.

Use of theft and other line loss detection by entities with AMI is up from slightly above 40 percent in 2006 to nearly 60 percent in 2008. Theft detection is used to identify customers who have physically re-routed the electrical cable that feeds their premises to circumvent the meter.

Use of AMI with home-area networks (HANs) did not rank high on the list of uses in the 2008 FERC Survey, although AMI-HAN integration is increasingly being included as a requirement in recent requests for proposals issued by utilities in North America. A home-area network "is a network contained within a user's home that connects a person's digital devices, from multiple computers and their peripheral devices to telephones, VCRs, televisions, video games, home security systems, 'smart' appliances, fax machines and other digital devices that are wired into the network."[15] Integration between home-area networks and advanced metering systems allows an entity to provide information to customers and remotely manage large loads (such as air conditioning and electric heat).

To support home-area networks, most entities are using advanced metering to remotely upgrade the firmware in the advanced meter associated with the home-area network. Entities believe that this is important to enable maintenance of meters and to allow utilities to upgrade functionality over time.

Remote connect/disconnect is used by entities such as electric utilities to connect or disconnect customers as they change residences or to disconnect or reconnect customers using pre-paid metering. This functionality is gaining in importance; surging from a relatively low 15 percent up to 48 percent usage. Pre-paid metering, sometimes associated with the remote connect/disconnect functionality, also saw modest gains.

Theft detection, a function of much interest in 2006, is used more in 2008. Other advanced metering functions used more from 2006 to 2008 are power quality management, distribution system asset management, and interfacing with water and gas meters. Use of advanced metering for load forecasting shows a decline since 2006 from over 40 percent usage then to below 30 percent usage in 2008.

The ability to remotely change metering parameters such as the length of the data interval measured, without a site visit to the meter location, was cited by slightly fewer entities in 2008 than in 2006. Only a small proportion of entities use advanced metering with price-responsive demand response programs.

Developments in Advanced Metering

This section reviews recent developments in the understanding of the size of the market for advanced metering, recent large utility deployments of advanced metering, and federal and state policies.

Outage mapping is the ability to use the advanced metering system to determine the extent of an outage once the outage has been detected. This is done by "pinging" a set of predetermined "bellwether" meters. *Outage restoration* is the ability to use the advanced metering system after repairs are underway to determine if power has been restored to all customers affected by a local outage before any repair crews move onto another area. Utility employees prefer using the AMI system to verify that power has been restored because it obviates having to call customers (often late at night) to verify.

[15] What is HAN? (August 28, 2008), *available at* http://www.webopedia.com/TERM/H/HAN.html.

Quantifying the Potential U.S. Marketplace

The 2007 FERC Demand Response Report identified 28 utilities that since 2005 had announced plans to deploy over 45 million advanced meters.[16] Recent contracts to purchase advanced metering systems by Southern Company (4.2 million advanced meters), Alliant Energy (one million advanced meters), Duke Energy's filing with the state of Indiana for an 800,000 advanced meter deployment bring planned deployments to nearly 52 million. These deployments are scheduled to take place over the course of the next five to seven years. The number is significant when one considers that nearly 60 million of North America's 145 million meters are already either AMI meters or automated meter reading[17] (AMR) meters.[18] The remaining 85 million are older electromechanical meters.[19] The plans reported above to deploy 52 million additional advanced meters would replace all but 33 million of the 85 million electromechanical meters. How many of the remaining 33 million electromechanical meters will eventually be replaced with advanced meters versus how many with AMR meters are yet to be determined. Notably, however, only one large investor-owned utility in the United States has announced plans to deploy an AMR system since May of 2005.[20]

Large Utility Deployment Plans

The following summarizes planned deployment schedules for the largest electric utilities preparing to deploy advanced metering:

- Southern California Edison's 5.3 million advanced meter deployment is slated to begin the fourth quarter of 2008, ramp up in 2009 and be completed in 2012.[21]
- Pacific Gas and Electric is seeking approval from the California Public Utilities Commission for additional ratepayer funding to upgrade its SmartMeter™ program to *newer* advanced meters, with plans to start installation in 2008 and complete full deployment of 5.1 million advanced meters by 2011.[22]
- San Diego Gas & Electric awarded a contract for 1.4 million advanced meters, with plans to begin broad deployments in February 2009 and complete full deployment in 2011.[23]
- Centerpoint Energy received approval from the Public Utility Commission of Texas for an initial deployment of 125,000 residential advanced meters between September 2008 and Fall

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[16] Appendix F, Utility AMI Implementation Projection, Table F-1, 2007 FERC Demand Response Report *available at*http://www.ferc.gov/legal/staff-reports/09-07-demand-response.pdf.

[17] Since AMR meters generally lack the two-way communicating capabilities of AMI meters, AMR meters cannot meet Commission staff's definition of advanced metering. In contrast with AMI and its fixed communications networks, AMR meters are read by drive-by or walk-by remote readers. *See* the 2007 Assessment of Demand Response and Advanced Metering at 24.

[18] Personal communication with Howard Scott of Cognyst Consulting, LLC (March 29, 2008).

[19] The electromechanical meters are older spinning disk meters, as opposed to the digital solid state technology on which newer AMR and AMI systems are based.

[20] Mid-American Energy Company awarded an AMR contract for its 1.2 million customer service area in May 2007. Press Release, Itron, MidAmerican Energy Company and Rocky Mountain Power to Deploy Turnkey Itron AMR System to Nearly Two Million Electric and Gas Customers in Iowa, Utah, Illinois, Nebraska and South Dakota (May 29, 2007), *available at*http://www.itron.com/pages/news_press_individual.asp?id=itr_015749.xml.

[21] *Many Utilities Starting to Develop AMI and Utility-of-the-Future Strategies - Part 2*, Energy Central (June 18, 2007), *available at* http://topics.energycentral.com/centers/datamanage/view/detail.cfm?aid=1495.

[22] *Id.*

[23] Press release, Itron, Gas & Electric Chooses Itron OpenWay® for Smart Meter Deployment (July 30, 2008), *available at* http://www.itron.com/pages/news_press_individual.asp?id=itr_016717.xml.

2009. Centerpoint Energy has contracted for up to two million advanced meters for intended full deployment to its Houston customers over the next three years.[24]

- DTE Energy awarded a contract for 2.6 million advanced meters at its Detroit Edison subsidiary with full deployment to begin in 2009.[25]
- Oncor announced award of a contract in May 2008 to provide advanced meters by 2012 to its 3 million residential customers.[26]
- Southern Company announced in January 2008 an agreement to purchase and deploy 4.3 million advanced meters for its four-state service area.[27] Its Alabama Power subsidiary is to begin a three-year deployment beginning in 2008, and its Georgia Power subsidiary began installing advanced meters in January 2008 with the intent to install 500,000 by the end of 2008 and complete its deployment by 2012.[28]
- Alliant Energy, with utilities in Wisconsin, Iowa, and Minnesota, announced in August 2007 that it would deploy advanced meters to over one million of its residential electricity customers starting in the fourth quarter of 2007.[29]
- In October 2007, American Electric Power announced an agreement with General Electric on a joint initiative to deploy over five million advanced meters to its 11-state service area by 2015, one-fifth (one million) of which would be deployed by 2010.[30] The specific AMI technology to be implemented has yet to be identified
- In June 2008, Duke Energy Indiana filed an application with the Indiana Utility Regulatory Commission to install 800,000 new advanced meters across its service territory as part of a larger smart grid proposal.[31]
- In June 2008, Arizona Public Service announced a contract to deploy 800,000 advanced meters to its customer base.[32]
- In September 2008, Delmarva, a subsidiary of Pepco Holdings, received approval from the Delaware Public Service Commission for a plan including the installation of more than 300,000 advanced meters for Delaware electricity and gas customers.[33]

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[24] *CenterPoint Energy to Install Advanced Meters* (September 1, 2008), *available at* http://www.metering.com/node/13478. *See also*, *Itron Selected by CenterPoint Energy as AMI Technology Provider*, Reuters.com (Wed. May 14, 2008), *available at* http://www.reuters.com/article/pressRelease/idUS117294+14-May-2008+BW20080514.

[25] Press Release, *Itron,* DTE Energy Selects Itron OpenWay® Technology for AMI Deployment (July 21, 2008), *available at* http://www.itron.com/pages/news_press_individual.asp?id=itr_016692.xml.

[26] *Oncor signs advanced metering contract*, (May 27, 2008), *available at* http://www.metering.com/node/12525.

[27] *Sensus Signs Contract with Southern Company for FlexNet(TM)* (January 14, 2008), *available at* http://www.smartbrief.com/news/aaaa/industryPR-detail.jsp?id=DFB51FD5-04E1-430B-8C1D-19EA83E627CC.

[28] Personal conversation with Edward Fischler of Southern Company (March 19, 2008); *Georgia Powers Smart Meter Rollout Continues* (June 27, 2008), *available at* http://www.metering.com/node/12877.

[29] Press Release, Sensus Metering Systems, Alliant Energy Selects Sensus as AMI Partner (August 27, 2007), *available at* http://na.sensus.com/Module/PressRelease/PressReleaseDetail/amr?id=42.

[30] *AEP, GE developing in-home 'smart meters'*, Matt Burns, Business First of Columbus (October 4, 2007), *available at* http://columbus.bizjournals.com/columbus/stories/2007/10/01/daily26.html.

[31] Press Release, Duke Energy, Duke Energy Indiana Proposes Sweeping Modernization of Its Power Delivery System (May 27, 2008), *available at* http://www.duke-energy.com/news/releases/2008052702.asp?sec=corporate.

[32] Press Release, Elster, Elster Awarded APS Contract to Provide 800,000 Smart Meters (June 20, 2008), *available at* http://www.elster.com/en/press_releases_704.html.

[33] See Delaware Public Service Commission Order No. 7420, the Matter of the Filing by Delmarva Power & Light Company for a Blueprint for the Future plan for Demand-Side Management, Advanced Metering, and Energy Efficiency (September 16, 2008).

State and Federal Support for Advanced Metering

Provisions promoting advanced metering in EPAct 2005 and in the Energy Independence and Security Act of 2007 (EISA 2007), along with state regulatory policies, are key drivers of growth in AMI sales, especially among large investor-owned utilities. In addition to enacting federal directives in support of advanced metering, Congress has also encouraged state policies in support of advanced metering. Several of the largest investor-owned utilities that are readying full deployments are located in states that have policies and incentives promoting and in some cases requiring use of advanced metering, such as Texas and California. Some states are implementing less traditional approaches to rate regulation, *e.g.*, accelerated depreciation, to provide an incentive (or remove a disincentive) for utilities to invest in advanced metering. Some utilities prefer, however, to request recovery via surcharge rather than through base rates so that they can track AMI costs separately from other equipment costs included in their rate base.[34]

Advanced metering may be considered one component of a smart grid system, and Congress has shown strong recent support for the smart grid concept. Congress included a number of directives in Title XIII of EISA 2007 calling for both federal and state encouragement of smart grid development. Title XIII states, "Smart Grid is defined to include a variety of operational and energy measures — including smart meters, smart appliances, renewable energy resources, and energy efficiency resources." EISA 2007 directs that states "shall consider" requiring each utility:

> prior to undertaking investments in non-advanced grid technologies… [to] demonstrate to the State that the electric utility considered an investment in a qualified smart grid system based on appropriate factors, including: (i) total costs; (ii) cost-effectiveness; (iii) improved reliability; (iv) security; (v) system performance; and (vi) societal benefit. [35]

Sec. 1307 of EISA 2007 also encourages rate-base capitalization of smart grid investments.[36] Congress took another significant step to promote advanced metering in the Emergency Economic Stabilization Act of 2008[37] passed in October 2008. This new legislation establishes permanent changes in how smart meters and other smart grid technologies are depreciated for federal tax purposes. Previously, these assets were figured at 20-year depreciation, but now the depreciation life is 10 years.

Challenges and Issues for Advanced Metering

AMI Industry Still Developing

Even as utilities press forward with advanced metering projects, a number of analysts deem AMI as not yet mature. In the words of one analyst, "to date, AMI or related Smart Grid initiatives have not

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[34] Will McNamara of KEMA reports that AMI is most commonly paid for with trackers and customer reimbursements on an annual basis. For example, in Con Ed's AMI filing with the New York State Public Service Commission, it requested approval of "a surcharge, adjusted annually, to recover all capital and O&M costs for AMI deployment, plus lost revenues." *New Trends Emerging for AMI Cost Recovery*, Energy Central (August 31, 2007), *available at* http://topics.energycentral.com/centers/datamanage/view/detail.cfm?aid=1547.

[35] Energy Independence and Securities Act of 2007, Pub. L. No. 110-140, §1305, 121 Stat. 1787 (2007).

[36] *Id.*

[37] Emergency Economic Stabilization Act of 2008, Pub.L. No. 110-343, 122 Stat 3765 (2008).

been implemented on anything resembling a large scale in the United States. Thus, although in many ways AMI technologies are maturing, they can hardly be characterized as being fully mature at this point."[38]

Numerous indicators support the notion that advanced metering is still a developing industry. For example, only within the past year or so has the industry begun to recognize the ability to remotely upgrade firmware and to store days or weeks of metering data in the meter's memory as standard functionality for advanced meters.

Another indication that advanced metering lacks maturity is the lack of integration of home-area networks with AMI systems. Last year, staff reported that ZigBee® had gained prominence as a HAN open standard. It was not until December 2007 that Comverge announced the nation's first ZigBee®-enabled demand response program as part of a pilot sponsored by the Center for the Commercialization of Electric Technologies.[39] Furthermore, appliances, to date, are generally not HAN-enabled, and HAN-integrated programmable communicating thermostats or in-home displays with HAN communications modules have only recently been introduced.[40] Ongoing debate continues concerning the embedding of HAN controllers in advanced meters versus the alternative of collecting aggregate customer information at distribution feeder or substation levels for demand response.[41]

General uncertainty over the development and evolution of standards and how they will impact networking technology, especially as regards HAN integration, has some state regulators reluctant to proceed with AMI specifications because they may discover a year or two later that they chose an inferior or unsupported technology. In New York, for example, the Public Service Commission declined to authorize a plan for full-scale AMI deployments by Consolidated Edison and Orange and Rockland as well as a separate plan filed by Rochester Gas & Electric. Instead, it decided to hold technical conferences to assess what advanced metering specifications it should require, given that:

> …many parties express caution that HANs and similar home appliance control systems are quite new, involve several competing designs, and currently lack standardization of design or cross-compatibility….[42]

Interoperability

One way to mitigate risks in planning AMI communications networks is to ensure interoperability. Interoperability allows seamless sharing of data and integration of functionality between digital electronic systems (*e.g.*, computing networks, communications networks, computers, computer programs, advanced metering systems, etc). The technological means of achieving interoperability is through standards for software, hardware, or firmware. Recognizing a need for standards that would enable interoperability, the U.S. Congress in EISA 2007 directed the National Institute of Standards and Technology to establish "protocols and model standards for information management to achieve

[38] *Many Utilities Starting to Develop AMI and Utility-of-the-Future Strategies*, Energy Central (May 29, 2007), *available at* http://topics.energycentral.com/centers/datamanage/view/detail.cfm?aid=1486.

[39] Press Release, Comverge, Comverge Provides Nation's First ZigBee® Enabled Demand Response System, (Dec. 19, 2007), *available at* http://ir.comverge.com//ReleaseDetail.cfm?ReleaseID=282476.

[40] Personal communications with Patti Harper-Slaboszewicz of Utilipoint (March 27, 2008).

[41] Personal communications with Roger Levy of Levy and Associates (April 1, 2008).

[42] Unofficial Transcript New York State Public Service Commission public meeting (Jan. 16, 2008), *available at* http://www3.dps.state.ny.us/pscweb/WebFileRoom.nsf/Web/B4055A9F579CE42A852573EC00665B77/$File/Transcript_011608.pdf?OpenElement.

interoperability of smart grid devices and systems."[43] In the meantime, many utilities proceeding with AMI plans are doing so cautiously, relying to some extent on open standards[44] to mitigate technological risk exposure or planning and budgeting for periodic technology upgrades to their advanced metering system over the life of their system.

Southern California Edison, for example, is taking several measures to insulate its Edison SmartConnect™ project from exposure to risks, including its commitment to open standards, such as the American National Standards Institute (ANSI) C12.19 standard[45] and the proposed (but not yet approved) C12.22 standard.[46] Furthermore, Southern California Edison's plans will allow it to change to a newer wide-area network technology after seven years if it deems it beneficial and cost-effective to do so. For its initial advanced metering deployment, Southern California Edison is planning to use existing cellular wide-area network communications for its initial advanced metering deployment. Southern California Edison's business plan, approved by the California Public Utilities Commission, includes a provision for Southern California Edison to be able to refresh or replace the wide-area network portion of its AMI network every seven years.[47]

Some U.S. utilities, vendors, consultants, and others are working together through the Utility Communications Architecture (UCA) International Users Group (UCAIug) and its UtilityAMI working group and task forces to develop interoperability requirements that would allow plug-and-play interfacing among the components of AMI systems. For example, the OpenHAN task force of the UtilityAMI Working Group released their 2008 HAN System Requirements Specification that is designed to facilitate standards and technology development to enable dissimilar home-area network protocols to interface and work interoperably. Southern California Edison, Consumers Energy, Pacific Gas and Electric, and American Electric Power, among others, are actively participating in UtilityAMI working group and task force meetings. Although focused on developing requirements from a utility perspective, vendors are actively involved in these activities to ensure that the requirements developed are technically and economically feasible in the marketplace.[48] Separately, in August 2008, American Electric Power, Consumers Energy, Pacific Gas and Electric, Reliant Energy, Sempra, and Southern California Edison announced they were working with the ZigBee® Alliance and the HomePlug®[49] Powerline Alliance "to develop a common application layer integrated solution for AMI and HAN."[50]

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[43] Energy Independence and Securities Act of 2007, Pub. L. 110-140, §§1303, 1305, 121 Stat. 1787 (2007).

[44] Open standards are standards that are publicly available and have associated with them various rights to use, unlike a proprietary or patented technological standard.

[45] The proposed C12.22 (Protocol Specification for Interfacing to Data Communications Networks) enables C12.19 metering data structures to be shared over any combination of "physical" network media. *Edison SmartConnect™: The Path Forward*, Utilipoint Daily IssueAlert (Jan. 21, 2008), *available at* http://www.utilipoint.com/issuealert/article.asp?id=2965.

[46] ANSI standard C12.19 (Utility Industry End Device Tables) enables metering data and data tables to be transferred from one computer application and system to another. Assessment of Demand Response & Advanced Metering, 2007 Staff Report, *available at* http://www.ferc.gov/legal/staff-reports/09-07-demand-response.pdf, p. 34.

[47] Personal communications with Paul De Martini, Director of the Edison SmartConnect™ program (March 31, 2008).

[48] OpenHAN meeting minutes (December 4, 2007), *available at* http://www.ucaiug.org/OpenHAN/Meeting%20Minutes/OpenHAN%20meeting_12_4_07.doc, and OpenHAN meeting minutes (Jan. 25, 2008) *available at* http://www.ucaiug.org/OpenHAN/Meeting%20Minutes/OpenHAN%20meeting_01_25_08.doc.

[49] HomePlug® is a HAN networking protocol that uses existing household electric wiring for its media, as compared with ZigBee®, which is a wireless HAN networking protocol.

[50] Press Release, HomePlug®.org, Utilities, ZigBee®® and HomePlug®® Join Forces to Create Wired HAN Standard (Aug. 25, 2008), *available at*http://www.HomePlug®.org/news/pr/view?item_key=6ddbf0d46d2156a8cb71f25199c02b2dfd20ce8b.

The intent is to enable HomePlug® and ZigBee® to work interoperably and integrally in HAN configurations.

AMI Cost-Benefit Analyses

Generally, before state commissions approve a utility's AMI deployment plan, the utility must first demonstrate a positive cost-benefit business case for its proposed AMI implementation. For many utilities, a positive business case requires including projected savings from demand response. A large fraction of AMI costs (ranging from 50 percent to 90 percent) can be justified by a reduction in traditional utility costs of operations or improved services, such as avoided meter-reading costs, faster outage detection, improved customer service, and better management of customer connections and disconnections.[51] Projected benefits from the demand response enabled by the AMI system may be included to bridge the cost-benefit gap based on what is recoverable from AMI-operational savings alone.[52]

There are several prominent examples of the inclusion of demand response benefits in cost-benefit business cases. Southern California Edison's business case for its Edison SmartConnect™ Deployment Proposal requires demand response to make up a 47 percent gap that is not covered by operational benefits from AMI.[53] Similarly, San Diego Gas & Electric's proposal requires demand response to make up about half of its cost-benefit justification.[54] For other utilities, the cost-benefit gap may not be quite so large. For Pacific Gas and Electric, operational savings accounted for 90 percent of its cost-benefit justification.[55] For Southern Company and its four operating companies, operational savings alone justify its AMI business case.[56] Southern Company's AMI contract does, however, stipulate that the metering solution must allow two-way communications to HANs either through the meter or alternatively bypassing the meter and connecting directly to HANs.[57] Alabama Power and Georgia Power, two subsidiaries of Southern Company, are considering using their advanced metering to enable demand response.

While operational benefits can be rather straightforward to determine, determining the value of demand response may not be so straightforward. Ultimately, demand response savings from AMI-enabled dynamic pricing programs depend on the number of participants who sign up for dynamic pricing or time-of-use programs and also their response to peak (or critical peak) prices, that is, on their price elasticity of demand. Participation rates for an optional ('opt-in') dynamic pricing program may be difficult to estimate in advance. In one recent study, The Brattle Group assumed a 20 percent participation rate as the likely scenario for opt-in dynamic pricing programs, while emphasizing that actual participation rates "will be highly dependent on the program design, the rates, and the success

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[51] Ahmad Faruqui, Ph.D. and Lisa Wood, Ph.D., The Brattle Group, *Quantifying the Benefits of Dynamic Pricing in Mass Markets, available at* http://www.eei.org/industry_issues/electricity_policy/quantifying_benefits_final.pdf.

[52] *Id.*

[53] Summary of Southern California Edison's Edison SmartConnect™ Deployment Proposal, p. 5, Southern California Edison Company's (U 338-E) Application for Approval of Advanced Metering Infrastructure Deployment Activities and Cost Recovery Mechanism, filed July 31, 2007. *available at* http://www.sce.com/NR/rdonlyres/34527A3F-FAEB-4650-A516-5AD5A07FFA4E/0/A0707XXXSCEAMIPhaseIIIApplication.pdf.

[54] *Advanced Metering Infrastructure: What Regulators Need to Know About Its Value to Residential Customers*, Nancy Brockway, NRRI, at 16 (Feb. 13, 2008), *available at* http://nrri.org/pubs/multiutility/advanced_metering_08-03.pdf.

[55] *Id.*

[56] Personal communications with Edward Fischler of Southern Company (Mar. 19, 2008).

[57] *Id.*

of the marketing and implementation strategy."[58]

Aggregated price elasticity can be modeled based on data from dynamic pricing or time-of-use pilots performed in various markets. The Brattle Group, for example, recently published its Pricing Impact Simulation Model (PRISM) Suite for use in projecting net present value of demand response for dynamic pricing programs.[59] Comparing results of numerous pricing pilots in addition to California's Statewide Pricing Pilot, The Brattle Group found average customer response to price changes to be greater when there is a larger price difference between peak and off-peak periods.[60]

Future-Proofing

Another important issue for utilities deploying AMI is concern about obsolescence. Regulators, vendors, utility executives, and ratepayers have a vested interest in future-proofing AMI implementations to avoid stranded costs of the old meter assets, additional costs for new assets, and costly, time-consuming, and difficult system reengineering and integration. Pacific Gas and Electric, which is implementing the first AMI project in California, has already had to deal with technological obsolescence even before getting its deployment underway. As a result, it filed with the California Public Utilities Commission in December 2007 for permission to increase its SmartMeter™ project cost by 50 percent, or about 26 cents per monthly bill for residential customers in order to upgrade from electromechanical to new solid-state advanced meters.[61] The newer advanced-meter specifications include added functionality that electromechanical meters are unable to provide, such as embedded HAN controls, upgradeable firmware in the meter, and load-limiting support.[62] To mitigate the risk of technological obsolescence, the California Public Utilities Commission has also "directed PG&E to regularly monitor emerging meter technologies and consider upgrades to the program."[63]

AMI-HAN Integration through HAN Controllers Embedded in Advanced Meters

The 2007 FERC report noted that certain industry analysts and home automation vendors are concerned about implementing AMI-HAN integration through controllers embedded in the advanced meters. They voice at least two concerns. The concerns include the prudence of allowing the utility, as a regulated franchise, to gain an advantage in an otherwise competitive home automation market, and "substantial privacy, security, communication, competitive, and hardware obsolescence issues concerning the embedding of HAN controllers in advanced meters."[64] Broad adoption of

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[58] Ahmad Faruqui, Ph.D. and Lisa Wood, Ph.D., The Brattle Group, *available at* http://www.eei.org/industry_issues/electricity_policy/quantifying_benefits_final.pdf, at Table 9. The authors state, "The opt-out percentage is not relevant for the PTR rate, which assumes that all customers are eligible for the "credit" but only 50% are aware of the PTR."

[59] Net Present Value is a standard method for using the time value of money to appraise long-term projects.

[60] The Brattle Group (Ahmad Faruqui, Ph.D. and Lisa Wood, Ph.D.) for EEI, *available at* http://www.eei.org/industry_issues/electricity_policy/quantifying_benefits_final.pdf, p.21.

[61] *PG&E Seeks Approval to Upgrade SmartMeter™ Technology*, Metering.com (Dec. 13, 2007), *available at* http://www.metering.com/node/11287.

[62] *PG&E Throws the First Pitch in the AMI Game*, Utilipoint Daily IssueAlert (July 25, 2008), *available at* http://www.utilipoint.com/issuealert/article.asp?ID=2894.

[63] *PG&E Seeks to Upgrade SmartMeter™ Technology to Enhance Customer, Operational Benefits*, Transmission and Distribution World (Dec. 27, 2007), *available at* http://tdworld.com/customer_service/pge-upgrading-smartmeter/.

[64] Personal communications with Roger Levy of Levy & Associates (Apr. 14, 2008). Mr. Levy points to several reasons why utilities think they need to pull information out of homes via the meters. For one, utilities need to verify the customer is actually responding to load-limiting requests. Secondly, central dispatchers want to be able to factor that information into dispatch decisions. An alternative approach, proposed by Mr. Levy, is to monitor energy use at a

interoperability standards, one based on the 2008 HAN System Requirements Specification, for example, may lessen concerns that utilities would have an unfair advantage in the home automation market, though the privacy concern might remain.

Enabling Residential Customers to Realize Savings and Benefits from Advanced Metering

Concerns about the impact of AMI deployment on residential customers, especially low-income customers, have been raised. Consumer advocates seek guarantees that with advanced metering customers will see real bill savings, that disabled, poor, and elderly customers will not be harmed by bearing disproportionate cost burdens compared with the benefits they receive from AMI, and that AMI will not be used to remotely disconnect or limit a customer's electric use without some programmatic safeguards.[65]

Various states have legislation to protect consumers against these burdens. In New York, for example, the Home Energy Fair Practices Act (HEFPA) regulations require a "last knock" at a customer's premises prior to disconnecting the customer for failure to pay a bill.[66] Such policy, however, potentially reduces the advantage of remote connect and disconnect available with AMI to some extent.

One approach to enabling customers to benefit from the use of AMI is through the use of peak-time rebates. Peak-time rebates let customers benefit from decreasing their energy consumption at times of peak prices, and yet be held harmless if they do not decrease their load. Peak-time rebates can be a particularly attractive program design, given the findings of The Brattle Group study showing that peak-time rebate programs should produce much higher total savings (close to 2.5 times the savings in net present value terms) than critical peak pricing programs where participants must opt-in and are also exposed to higher rates during critical periods.[67]

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distribution feeder or substation level where the utility and central dispatcher would effectively receive real time measurement and verification of the diversified aggregate impact of the demand response faster than is possible when collecting individual household demand response measurements.

[65] *Smart Meters, Demand Response and "Real Time" Pricing: Too Many Questions and Not Many Answers*, Barbara R. Alexander (July 2007), *available at* http://www.narucmeetings.org/Presentations/Dynamic%20Pricing%20NARUC%202007.ppt, slide 23.

[66] State of New York Public Service Commission, at a session of the Public Service Commission held in the City of New York on Dec. 12, 2007, *available at* http://www3.dps.state.ny.us/pscweb/WebFileRoom.nsf/Web/6DEBE23FB000219D852573B60068A93B/$File/202C_05e0934etal_order.pdf?OpenElement.

[67] Ahmad Faruqui, Ph.D., and Lisa Wood, Ph.D., The Brattle Group, *available at* http://www.eei.org/industry_issues/electricity_policy/quantifying_benefits_final.pdf, Table 9.

Chapter III. Demand Response

This chapter addresses the second and third areas that Congress directed the Commission to consider in EPAct section 1252(e)(3):

(B) existing demand response programs and time-based rate programs, and
(C) the annual resource contribution of demand resources.

In this chapter, Commission staff presents the results of the 2008 FERC Survey of demand response programs, along with an estimate of the resource contribution associated with these programs, and compares, where appropriate, the 2008 and 2006 survey results.

Results from the 2008 FERC Survey indicate that about eight percent of customers in the United States are on some form of demand response program, either incentive-based demand response or a time-based rate. There have been changes in customer participation in these programs. For example, the number of customers on real-time pricing and critical peak pricing programs increased since 2006.

Regarding the demand response resource contribution nationally, Commission staff estimates a potential peak load reduction of about 41 GW. This represents approximately 5.8 percent of the total U.S. projected electricity demand for summer 2008,[68] and a nine percent increase in potential from the 38 GW estimate of potential peak load reduction in 2006.

Below we address:

- FERC 2008 Demand Response Program Survey Results, and
- Demand Response as a Resource.

FERC 2008 Demand Response Program Survey Results

The 2008 FERC Survey requested that respondents provide information on up to ten demand response programs for each customer class. Information collected on these programs included:

- name of program,
- type of program,
- description of program,
- applicable customer class,
- number of enrolled customers,
- maximum demand of enrolled customers in 2007 (MW),
- potential peak load reduction in 2007 (MW),
- actual peak reduction in 2007 (MW),
- potential MWh change in 2007,
- actual annual MWh change in 2007, and
- whether participants in the program are excluded from taking part in other demand response programs.

[68] Total forecasted coincident peak demand of 752,579 MW. NERC, *2008 Summer Assessment* (May 2008).

The response rate was good for a voluntary survey – 55 percent – almost identical to the response rate achieved in 2006. The response rate was generally high (greater than 60 percent) for most medium to large entities, and particularly high for medium to large investor-owned utilities so that a large fraction of the U.S. electricity load is captured in the survey. In addition, all of the Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) that offer wholesale demand response programs responded.

For purposes of this report, demand response programs are categorized as either incentive-based demand response programs or time-based rate programs. The following sections describe the programs that fit into these two categories and summarize the information provided by respondents on the number of customers that are currently participating in each of these types of programs.[69]

Incentive-Based Demand Response Programs

Incentive-based programs involve an inducement or incentive for customers to reduce their electricity consumption. This is in contrast to the second type, which involves the direct price signals associated with time-based rates. Incentive-based demand response programs generally provide a direct means for controlling load and are therefore used by load-serving entities, electric utilities, or grid operators to manage costs and maintain reliability, especially in emergency conditions when immediate and predictable demand response is required.

The kinds of incentive-based programs include:[70]

- **Direct load control**: A demand response activity in which the program sponsor remotely shuts down or cycles a customer's electrical equipment (like an air conditioner or water heater) on short notice.
- **Interruptible/curtailable rates**: Curtailment options integrated into retail rates that provide a rate discount or bill credit for agreeing to reduce load during system contingencies.
- **Emergency Demand Response:** Emergency demand response programs provide incentive payments[71] to customers for reducing their loads during reliability-triggered events, but curtailment is voluntary.[72] 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.
- **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. In exchange for being obligated to curtail load when directed, participants receive guaranteed payments. Capacity market programs are typically offered by wholesale market providers such as RTOs and ISOs that operate installed capacity (ICAP) markets, and are the organized market analog of interruptible/curtailable tariffs.

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[69] Appendix F lists the entities that reported offering each type of demand response program.

[70] The set of incentive-based demand response programs listed here mirrors the set identified by the U.S. Department of Energy (DOE). *Benefits of Demand Response in* Electricity Markets, and Recommendations for Achieving Them: A Report to the U.S. Congress. February 2006, *available at*http://www.oe.energy.gov/DocumentsandMedia/congress_1252d.pdf.

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

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

- **Demand Bidding/Buyback Programs**: 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 be willing to curtail at posted prices.
- **Ancillary services market programs**: Demand response programs in which customers bid load reductions in RTO or ISO ancillary services markets.

1) Direct Load Control

Direct load control programs are one of the most common types of demand response programs. They are typically operated to balance supply and demand at system peak, but are also operated to avoid high on-peak electricity purchases. There have been direct load control programs with meter-based and consumer-based equipment controls since 1968,[73] and these programs expanded significantly during the 1980s and 1990s. Survey responses indicate an approximate 3.5 percent growth in customer enrollment in direct load control programs since 2006, up from 4.95 million customers to 5.13 million.

Figure III-1 displays the results for the reported number of customers enrolled in direct load control programs by region and type of entity. Investor-owned utilities' direct load control programs enroll the largest number of customers, accounting for approximately 78 percent of all reported direct load control program customers. Of all the regions, FRCC and RFC enroll the largest number of customers.

In addition, FRCC has the highest reported customer enrollment percentage, with almost 13 percent of customers in FRCC participating in direct load control programs. The MRO also has a high customer participation rate, slightly more than 10 percent. Two utilities in these regions account significantly toward the high participation rates. In FRCC, Florida Power & Light operates the largest direct load control program with 782,227 customers, an increase of 41,657 customers (5.6 percent) since 2006. In MRO, the program operated by Northern States Power Company is the second largest with 370,797 customers, an increase of 87,480 (30.9 percent) since 2006. Southern California Edison had the largest increase in enrollment, up 71 percent to a reported 284,336 enrolled.

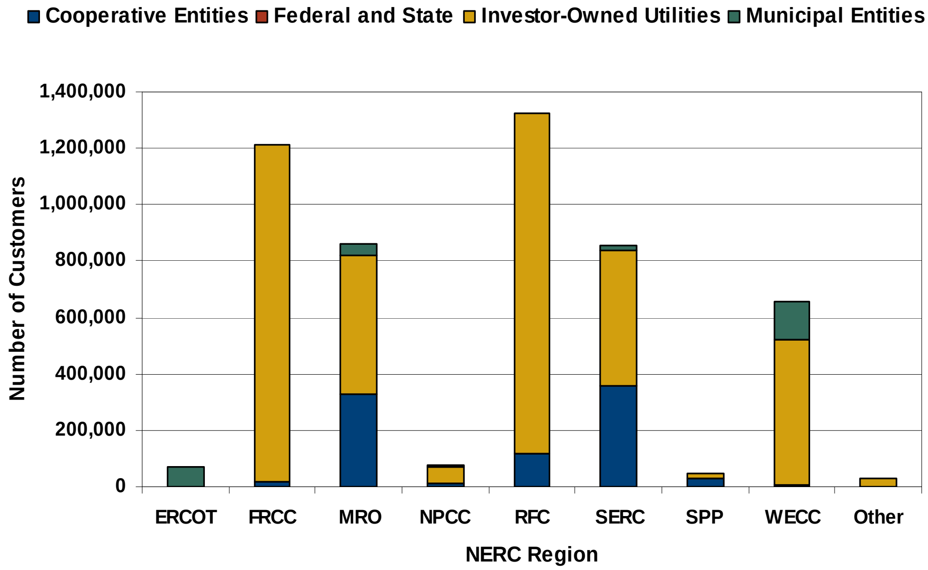
2) Interruptible/Curtailable Rates

Another commonly implemented demand response program is one based on interruptible/curtailable rates. Interruptible/curtailable rates provide a rate discount or bill credit to customers who agree to reduce load during system contingencies. A utility typically offers these rates to its largest industrial and commercial customers. Figure III-2 shows the distribution of the entities who report offering interruptible/curtailable rates by type of entity and region.[74] All types of entities offer interruptible/curtailable rates. The regions with the largest number of entities that offer these rates are the MRO, SERC, and RFC. The 2006 FERC Survey identified the same regional pattern.

[73] 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.

[74] For the purposes of Figure III-2 and later figures that report information for each entity type, Commission staff has combined cooperatives, cooperative G&Ts, and political subdivisions into "Cooperative Entities." Similarly, municipal utilities and municipal marketing authorities are combined into "Municipal Entities." Federal entities, such as Bonneville Power Administration, and state utilities, such as the Long Island Power Authority, are combined into "Federal and State."

Figure III-1. Number of customers enrolled in direct load control programs by region and type of entity



Percent of customers in the region in a direct load control program	0.7%	13%	10.4%	0.5%	3.8%	2.9%	0.7%	2.2%	3.2%

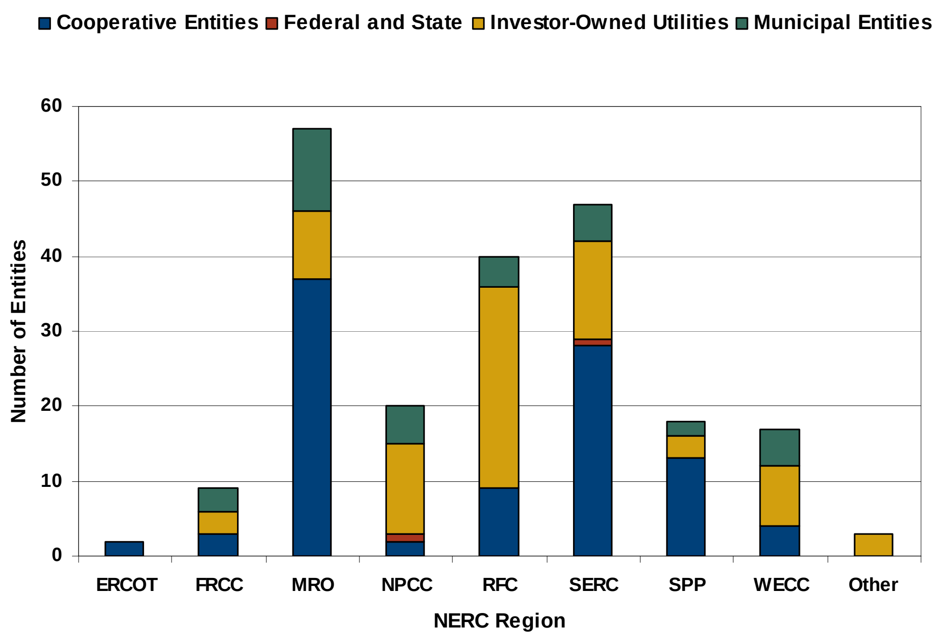
Source: 2008 FERC Survey
Note: Other includes ASCC and Hawaii.

3) Emergency Demand Response, Capacity Market and Demand Bidding/Buyback Programs

The emergency demand response, capacity market, and demand bidding/buy back programs are largely associated with wholesale markets and have developed in the last decade. Almost all regions of the United States report an increase in the use of these newer forms of incentive-based demand response since the 2006 FERC Survey.

In the 2008 FERC Survey, 274 entities report offering these types of programs, a 217 percent increase since that reported in 2006. This increase is largely driven by an increase in the number of entities offering emergency demand response programs, from 59 to 136. Eighty-one entities report offering capacity market programs, and 57 entities report offering demand bidding/buyback programs.

Figure III-2. Number of entities reporting interruptible/curtailable rates by region and type of entity



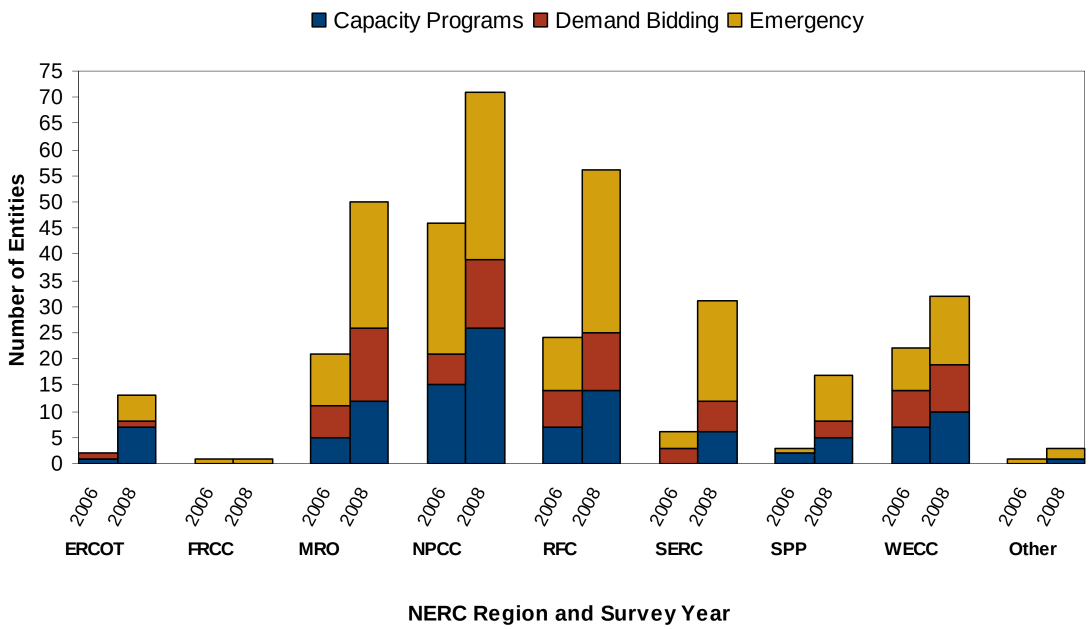
Source: 2008 FERC Survey
Note: Other includes ASCC and Hawaii.

As shown in Figure III-3, each region reported an increase in the number of entities offering these programs. The regions showing the largest increase in the number of entities reporting these three kinds of programs (NPCC, RFC, MRO and ERCOT) also have organized wholesale markets operated by RTOs and ISOs. As discussed in prior Commission staff reports and as discussed in the next chapter, these wholesale markets have been actively integrating demand response resources.

4) Ancillary Services

Respondents identify 249 demand response programs as ancillary services programs. However, many of the respondents also identify these ancillary services programs as a capacity market program or other incentive-based program. To resolve this overlap in categorization, Commission staff reviewed each demand response ancillary services program reported in the 2008 FERC Survey and determined that the resources in the majority of these programs are not able to provide the ancillary services included in Open Access Transmission Tariffs. Therefore, this discussion does not analyze the number of entities offering such programs or the number of customers reported in the 2008 FERC Survey as enrolled in them. Instead, this section describes the major RTO and ISO ancillary services programs in ERCOT, the California ISO, and PJM.

Figure III-3. Number of entities reporting capacity, demand bidding & emergency programs by region in 2006 and 2008



Source: 2006 FERC Survey and 2008 FERC Survey
Note: Other includes ASCC and Hawaii.

In ERCOT, at the end of 2007, 130 customers with a combined rated capacity of 2,069 MW registered as a Loads acting as Resources (LaaRs)[75] in order to participate in the ERCOT ancillary services markets. In the past two and a half years, ERCOT has had seven system-wide LaaR deployments, none of which occurred during ERCOT's peak load period. In 2007, ERCOT deployed its LaaRs for three system-wide events, and the average demand response during those events was 1,164 MW.

In the California ISO, the Participating Load Program allows qualifying loads to bid directly into the non-spinning, replacement reserve, and supplemental energy markets. At present, the large water pumps operated by the California Department of Water Resources serve as the primary resource in this program. About 2,500 MW of pumped-storage hydroelectric facilities operated by the California Department of Water Resources, Pacific Gas & Electric, and Southern California Edison participate in the program.

PJM operates ancillary services programs for both synchronized reserve and regulation. Synchronized reserve is a component of the operating reserves required by RFC, the regional reliability council. Currently, demand response resources may not provide more than 25 percent of the synchronized reserve requirement in any zone. As of the end of 2007, 62 customers participated in the synchronized reserves market and supplied 125 MW of capacity at the system peak. As of the end of 2007, no customers had met the requirements necessary to provide regulation service.

[75] Load Acting as a Resource (LaaR) is an interruptible/curtailable program in which qualified customers can bid to provide operating reserves.

Time-Based Rate Programs

In addition to the incentive-based demand response programs discussed above, demand response is also accomplished through the use of direct price signals associated with time-based rates.

The 2008 FERC Survey requested information on the prevalence and use of time-based rate programs across the United States. The number of entities that report offering time-based rates increased from 462 to 503, a nine percent increase from the 2006 to 2008 survey responses (see Table III-1). In the 2008 FERC Survey, 315 entities report that they offer time-of-use rates, 100 entities report offering real-time pricing rates, and 88 entities report offering critical peak pricing rates, indicating a marked change in the type of programs offered. The survey results show a 14 percent decline in the number of entities reporting time-of-use rates, and a significant increase in the number of entities offering real-time pricing and critical peak pricing rates – reported real-time pricing rates and critical peak pricing rates increased by 66 percent and 144 percent respectively since 2006. The following discussion presents more detail.

Table III-1. Number of entities offering time-based rates

Time-based Rate	Number of Entities (2006 Survey)	Number of Entities (2008 Survey)
Time-of-Use Rates	366	315
Real-time Pricing	60	100
Critical Peak Pricing	36	88
TOTAL	462	503

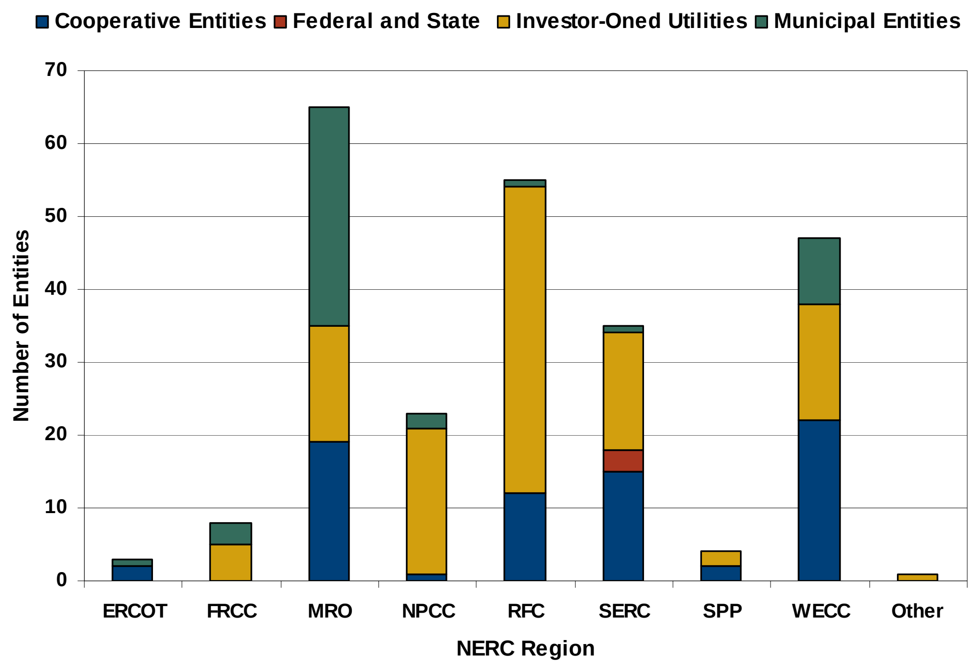
Source: 2006 FERC Survey and 2008 FERC Survey

1) Time-of-Use Rates

Time-of-use rates are the most prevalent time-based rate, especially for residential customers. Time-of-use rates typically establish two or more periods within a day 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 usually cover some part of the evening and night, as well as weekends. The length of the on-peak period varies, but typically would be between 8 a.m. and 8 p.m. The choice of the hours for the time-of-use periods differs widely among utilities, based on the timing of their peak system demands over the day, week, or year. Some time-of-use rates have only two prices, one for peak and one for off-peak periods, while others also have a third period with a “shoulder period” rate. Some seasonal rates have different rates for two or more seasons. Time-of-use rates for large customers may include time-based capacity as well as energy charges.

Figure III-4 shows the number of entities that report offering time-of-use rates to their residential customers by NERC region. Survey results show that 241 of the 315 entities with time-of-use rates offer a time-of-use rate to their residential customers. Of the 241, 118 are investor-owned utilities, and 73 are cooperative entities. The MRO region has the highest number of entities (65) offering time-of-use rates to residential customers. The RFC region follows with 55, and the WECC region with 47. Only three ERCOT entities report offering time-of-use residential rates. None of the investor-owned utilities and a limited number of unregulated retailers report that they offer time-of-use rates in ERCOT.

Figure III-4. Number of entities reporting residential time-of-use rates by region and type of entity



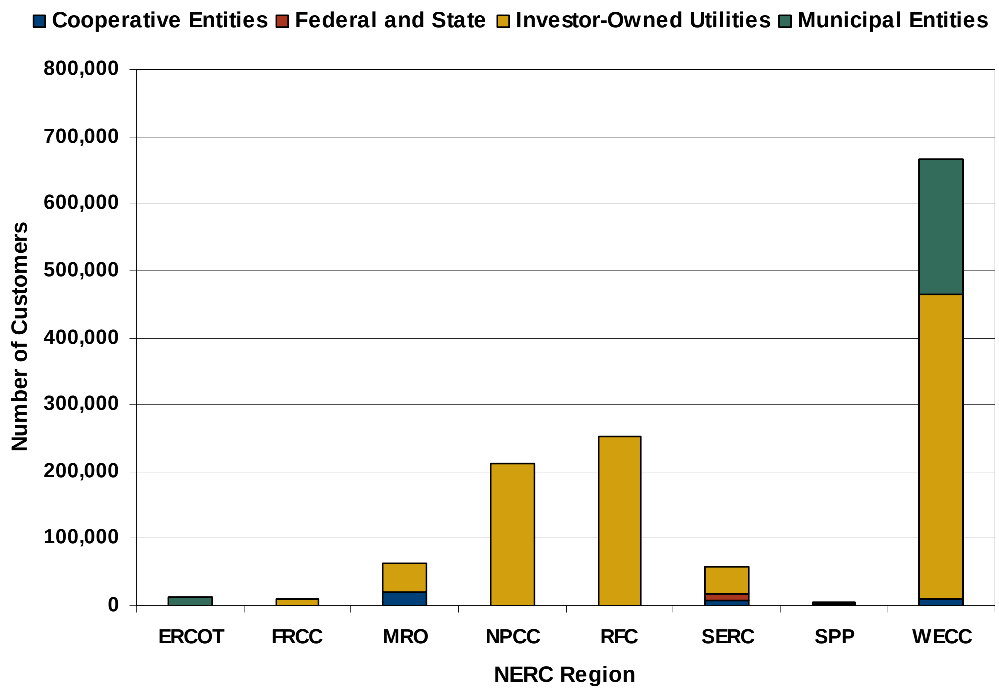
Source: 2008 FERC Survey
Note: Other includes ASCC and Hawaii.

Figure III-5 shows the number of residential customers reported to be on time-of-use rates by region. The number of customers on time-of-use rates is much greater in WECC compared to all other regions. Two large time-of-use rate programs operated by a pair of Arizona utilities, Arizona Public Service and Salt River Project, comprise most of the WECC total and together include over 500,000 customers. Even though more entities in the MRO and RFC regions report offering time-of-use rates, the Arizona programs cover more customers.

2) Real-Time Pricing

Under real-time pricing, retail electricity prices vary at least hourly during the day, directly reflecting the underlying cost of electricity. The direct connection between the varying cost of power and retail rates made possible by real-time pricing introduces price responsiveness into the retail market if retail customers are directly exposed to such prices.

Figure III-5. Number of residential customers reported as enrolled in time-of-use rate programs by region and type of entity



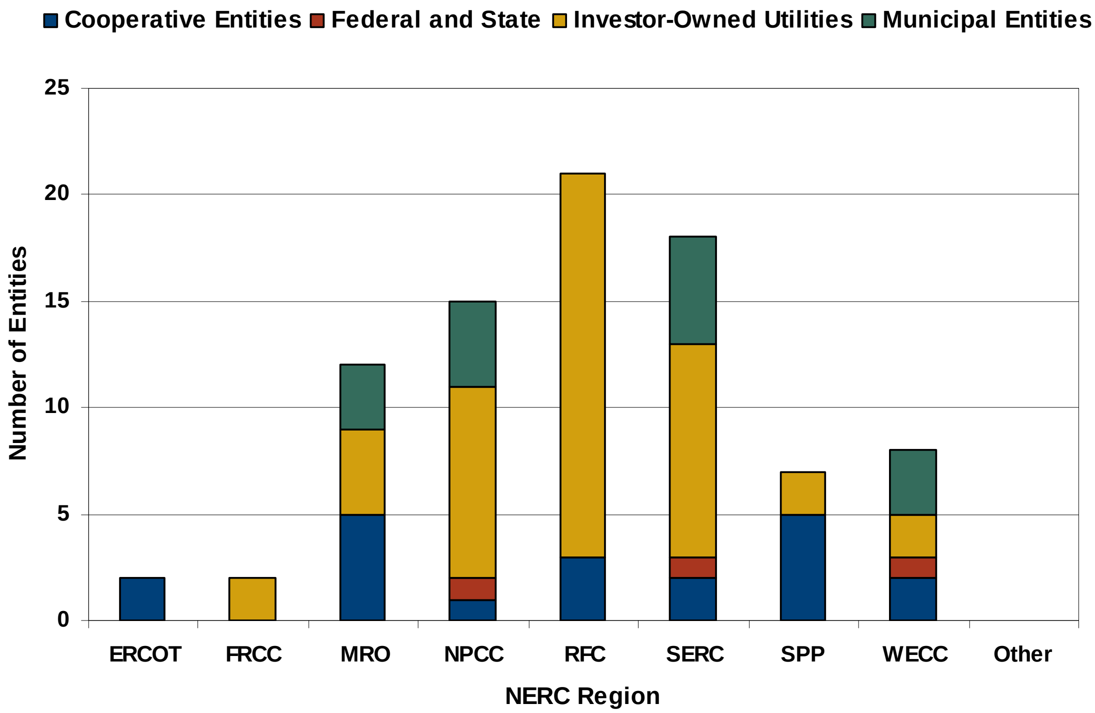
Source: 2008 FERC Survey

According to the responses, 85 entities report offering at least one real-time pricing program for retail customers (see Figure III-6). This represents a 54 percent increase since the 2006 FERC Survey. Despite their smaller absolute number, investor-owned utilities represent 55 percent of all survey respondents offering real-time pricing. Almost half of all the entities offering real-time pricing at retail are located in either RFC (21) or SERC (18). In RFC, there are a relatively large number of entities offering real-time pricing as the default rate for large customers in New Jersey, Maryland, and Pennsylvania.

3) Critical Peak Pricing

Critical peak pricing is a relatively new form of retail time-of-use rate that specifies a very high price for electricity use only when needed to manage a critical peak problem. Critical peak pricing events may be triggered by system contingencies or when the utility faces extremely high prices when procuring power in the wholesale market or operating high-cost peaking units. Unlike time-of-use blocks, which are typically in place for six to ten hours during every day of the year (or season), the times when critical peaks occur are not designated in the rate. They are determined on short notice, as needed, for a limited number of days during the year. Critical peak pricing can be used together with either a time-of-use or a time-invariant rate. Critical peak pricing can be considered a reliability-based demand response program since it is implemented in real time when reliability is threatened.

Figure III-6. Number of entities reporting retail real-time pricing by region & type of entity



Source: 2008 FERC Survey
Note: Other includes ASCC and Hawaii.

Critical peak pricing rates have several variants, including:

- **Fixed-period critical peak pricing**: In fixed-period critical peak pricing, 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 days called per year is also usually predetermined. The events are typically called the day before so that customers have time to plan to reduce consumption.
- **Variable-period critical peak pricing**: In variable-period critical peak pricing, the time, duration and day of the price increase are not predetermined. The events are usually called on the day of the event. Variable-period critical peak pricing typically applies when devices are available that allow automatic responses to critical peak prices, such as communicating thermostats.
- **Variable peak pricing**: The critical peak prices in the prior two types of critical peak pricing are fixed in rate schedules. Under variable peak pricing, the off-peak and shoulder-period energy prices would be set in advance for only a designated length of time, such as a month or more, based on wholesale prices and market conditions. The advantage of variable peak pricing is that it more directly links the wholesale market to retail pricing.

- **Peak time rebates**: Peak time rebates are retail rate schedules in which customers remain on fixed rates but receive rebates for load reductions during critical peak periods. Peak time peak rebates are also known as critical peak rebates.

According to the 2008 FERC Survey results, 194 entities indicate that they operate programs with critical peak pricing components. However, most of these respondents also categorize their programs as time-of-use rates or other incentive-based demand response programs. For example, several RTOs and ISOs indicate that their wholesale demand response programs were critical peak pricing programs. Commission staff reviewed the reported programs and determined that only 20 of them fit our definition of critical peak pricing programs. The programs that fit our definition are small in size and few in number. The largest, operated by Gulf Power Company, enrolls slightly less than nine thousand residential customers. Southern California Edison operates a critical peak pricing program for its large customers with maximum demands of 500 kW and above, and enrollment in the program of 31 customers.

Demand Response as a Resource

This section discusses the potential for demand response on a national and regional basis. Survey respondents reported potential peak load reduction totaling 37 GW for all customer classes in all regions. Using this information, and other available data, we estimate that the potential annual resource contribution of demand response resources in the United States is about 41 GW, which is about 5.8 percent of forecasted U.S. peak demands for 2008.[76]

This section has two subsections:

- 2008 FERC Survey results for the demand response resource contribution, and
- Estimated nationwide demand response peak load reduction.

2008 FERC Survey Results for the Demand Response Resource Contribution

For each demand response program or rate, the 2008 FERC Survey asked respondents to provide estimates of the potential peak load reductions (in MW), actual peak reductions (in MW), potential MWh change and actual MWh changes as of the end of the 2007 calendar year.[77] Potential peak load reduction represents the load that can be reduced either by the direct control of the utility system operator or by the customer in response to a utility request to curtail load and forms the basis for staff's estimate of the annual resource contribution of demand resources requested by Congress.[78]

Actual peak reduction is the reduction in MW consumption achieved by customers that participated in a demand response program that coincides with the annual system peak of the utility (or the RTO or ISO to which a respondent utility belongs) for the calendar year 2007.

[76] The term U.S. peak demands refers to the NERC's forecasts of peak demand for 2008 for the eight NERC regions. NERC regional peak demand forecasts are by their nature non-coincident.

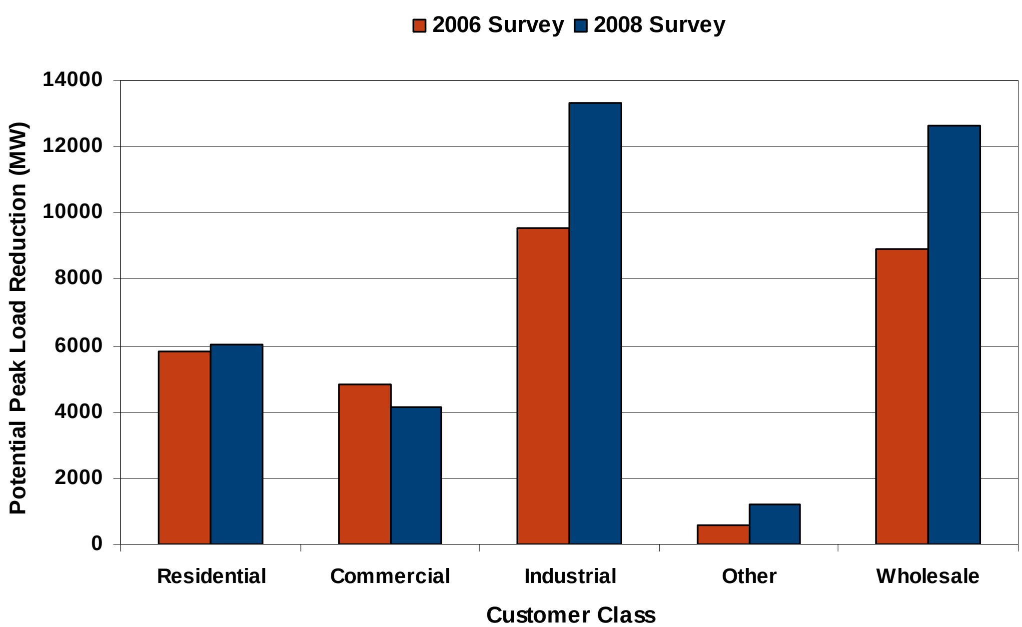
[77] Potential peak load reduction is defined as "the installed load reduction capability during the time of annual system peak load," consistent with the Energy Information Administration's definition.

[78] Commission staff used the same methodology to develop estimates of resource contribution as in the 2006 Demand Response Report.

1) Potential Peak Load Reduction Reported by Survey Respondents

The total potential peak load reduction reported by entities for all regions and customer classes is 37,335 MW, up 26 percent from the 2006 FERC Survey results, and represents approximately five percent of the total forecasted U.S. peak demands for summer 2008 (752,579 MW)[79]. As can be seen in Figure III-7, all customer classes except commercial reported an increase. The wholesale[80] and industrial classes account for the majority of the increase, 42 and 39 percent respectively whereas commercial accounts for a 14 percent decline.[81] The large increases in the reported potential peak load reduction within the wholesale and industrial classes are in keeping with the increase in entities offering demand response programs discussed earlier, particularly in the regions with organized wholesale markets.

Figure III-7. Potential peak load reduction by customer class in 2006 and 2008



Source: 2006 FERC Survey and 2008 FERC Survey

[79] NERC *2008 Summer Assessment*, May 2008.

[80] For the purposes of this report, the potential peak load reduction associated with wholesale demand response resources refer to the reductions reported by wholesale providers that cannot be attributed to specific retail companies. For RTO's or ISO's wholesale demand response programs, retail companies and non-utility service providers aggregate individual customer load reductions and sell or provide the reductions to the RTO or ISO. Cooperative G&Ts and municipal marketing entities are wholesale entities that aggregate or direct the load reductions of their members. See Appendix D for a discussion on how Commission staff addressed potential double-counting reported potential peak load reductions by retail companies as wholesale demand response resources.

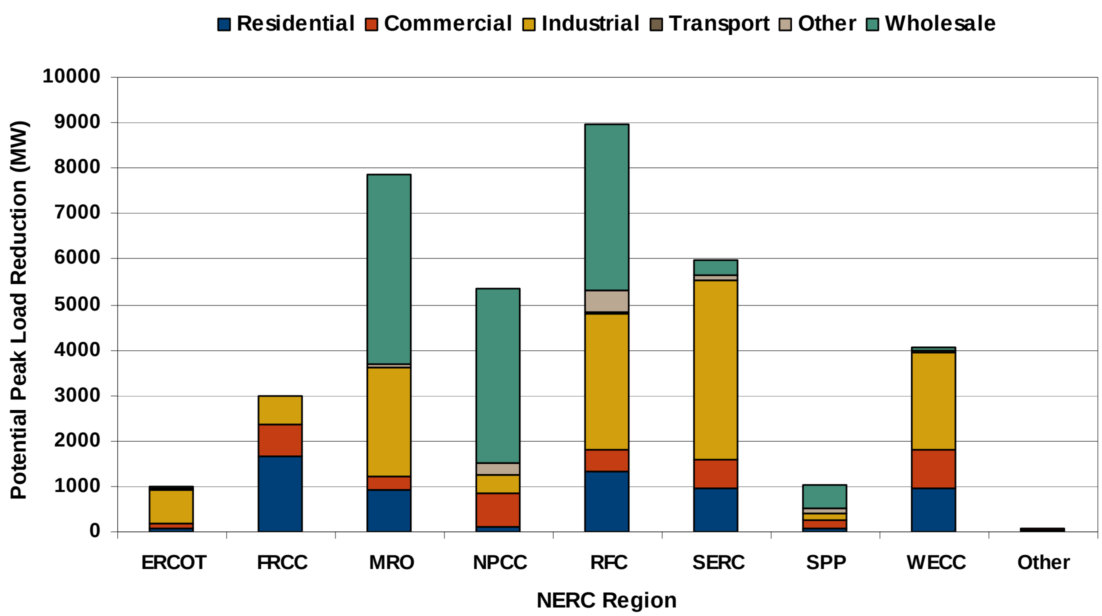
[81] Note that the decline in the potential peak load reduction associated with the commercial class may be an artifact of variation in how commercial and industrial customers are classified by respondents. Most electric utilities categorize their nonresidential customers by KW and KWh size rather than by standardized customer classifications. Consequently, responses to the 2006 survey may have classified customers as commercial customer, but then changed their classification of these same customers to industrial in the 2008 FERC Survey.

Wholesale demand response programs, primarily operated by RTOs and ISOs, cooperative G&Ts (such as the North Carolina Electric Cooperative) and municipal market authorities (such as the Massachusetts Municipal Wholesale Electric Company), account for 12,656 MW or about 34 percent of the reported total potential peak load reduction nationally. They represent 40 percent or more of the reported potential peak load reduction in four regions: RFC (40 percent); SPP (48 percent); MRO (53 percent); and NPCC (72 percent). In contrast, they account for less than four percent of the reported potential peak load reduction in the WECC and ERCOT regions and only six percent in the SERC region. No entity in the FRCC region reported any wholesale demand response programs, partly because an organized wholesale market is not operative in Florida.

Commercial customers account for about 11 percent of the reported potential peak load reduction whereas residential customers account for 16 percent. Residential potential peak load reduction is greatest in two regions: FRCC with 1,644 MW, or 27 percent of national residential peak load reduction potential and RFC with 1,337 MW, or 2 percent. Residential customers in FRCC provide 55 percent of that region's reported potential peak load reduction.

The RFC region accounts for the largest share of potential peak load reduction for existing demand response resources (24 percent) followed by the MRO region (21 percent) and SERC (16 percent). These results are similar to the results from the 2006 FERC Survey. Figure III-8 graphs the reported potential peak load reduction by region and shows the contribution of each customer class within each region.

Figure III-8. Reported potential peak load reduction by region and customer class

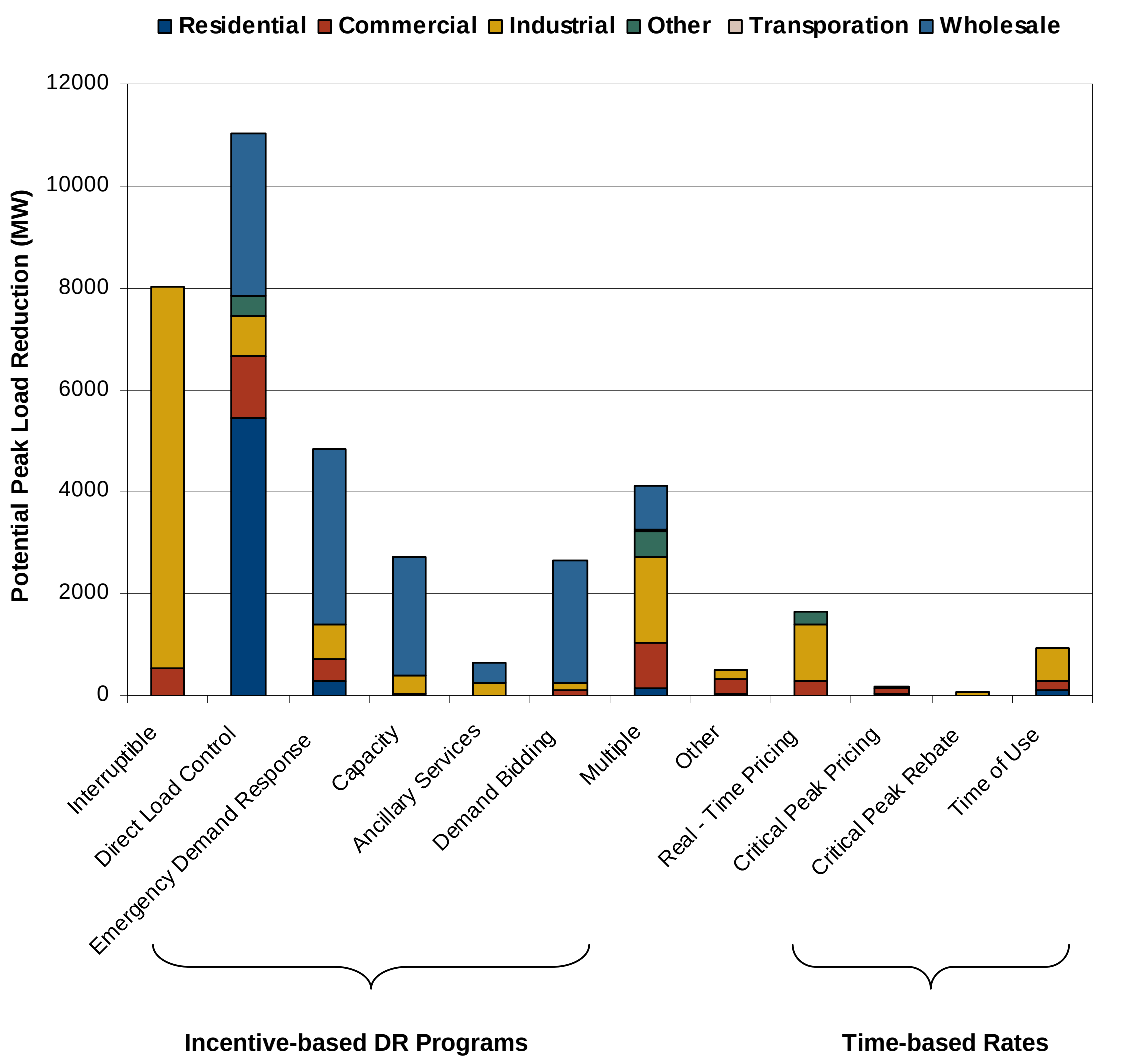


Source: 2008 FERC Survey
Note: Other includes ASCC and Hawaii.

Figure III-9 presents potential peak load reduction by type of demand response program. According to the 2008 FERC Survey responses, direct load control programs represent the largest portion of national peak load reduction potential, accounting for 11,045 MW of potential peak load reduction, or

30 percent of national peak load reduction potential. Interruptible/curtailable rates account for 8,032 MW, or 22 percent of the national peak load reduction potential. The relative ranking of direct load control and interruptible/curtailable rates in terms of their portion of the national peak load reduction changed from their 2006 rankings largely due to increases in customer enrollment in key direct load control programs and the increase in reported peak load reduction potential from direct load control programs from cooperative entities. Emergency demand response programs account for 4,817 of national peak load reduction potential, or 13 percent of the national total.

Figure III-9. Potential peak load reduction by type of program and by customer class



Source: 2008 FERC Survey

2) Actual Reported and Estimated National Potential Peak Load Reductions

On a national basis, respondents to the 2008 FERC Survey report about 13,600 MW of actual peak load reductions in 2007. In interpreting information on actual peak load reductions for demand response programs or time-based rates, it is important to recognize that:

- Certain types of demand response programs (interruptible/curtailable rates, emergency demand response programs, and direct load control) are often only called on during system emergencies, which are infrequent and do not occur each year because they are dependent on weather and system conditions;
- Activity levels in "economic" demand response programs (*e.g.*, demand bidding) are influenced by the volatility and level of electricity commodity prices;
- Demand response program design features can influence customer response (*e.g.*, penalties for non-performance);
- Most utilities do not routinely track or estimate actual peak load reductions for customers on time-based rates;
- NERC is implementing reliability standards, many of which address demand response forecasting and implementation, with penalties for non-compliance. Utilities are in the process of revising forecasts of demand response resources; and
- Some programs are used for ancillary services, such as operating reserves, frequency and voltage support, and may be much less likely to be called on during system peaks.

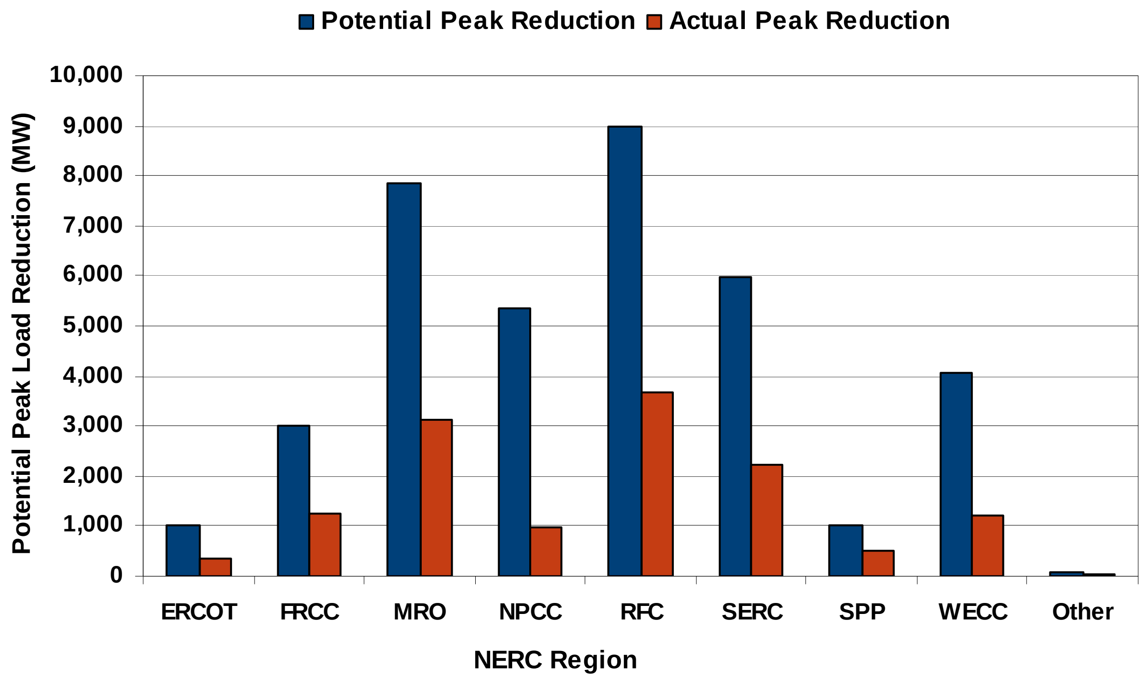
Figure III-10 presents reported potential and actual peak load reductions for demand response programs for each region.

Three regions (RFC, MRO, and SERC) account for 69 percent of actual national peak load reduction. The RFC region reports the largest actual peak load reduction of 4,227 MW, which is approximately 42 percent of the potential peak load reduction. The next largest actual peak load reduction is associated with the MRO region (3,130 MW) and is approximately 39 percent of the potential. The ratio of actual to potential peak load reduction is the highest in the FRCC region. This likely reflects the long-standing, integral role that demand response resources play in meeting Florida's electricity demand.

Estimated Nationwide Demand Response Peak Load Reduction

As noted earlier, the response rate to the demand response section of the survey was 55 percent. To provide a more complete assessment of the national potential, Commission staff has developed an estimate of peak load reduction from all demand response programs in the United States. This national peak load reduction estimate includes both peak load reductions reported by survey respondents and an estimate of peak load reduction for entities who did not respond to the 2008 FERC Survey. The estimates of peak load reduction from non-respondents are based on a number of sources, including the 2006 and 2008 FERC Survey responses and information on peak load reduction potential from 2006 EIA Form 861, RTO or ISO demand response program evaluations, and other sources.

Figure III-10. Potential and actual 2007 peak load reduction by demand response resources, by region



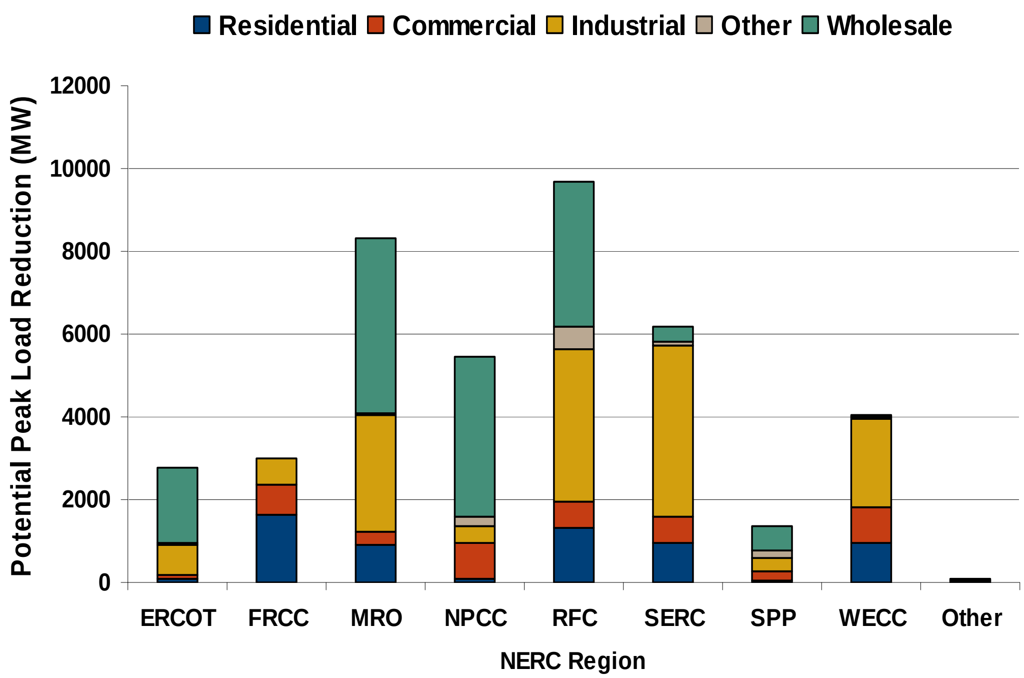
Source: 2008 FERC Survey
Note: Other includes ASCC and Hawaii.

The result is an estimated demand response peak load reduction potential (or resource contribution) from currently operated demand response programs of 40,943 MW. This represents approximately 5.8 percent[82] of the total U.S. projected electricity demand for summer 2008. This 2008 estimate represents a nine percent increase in potential from the 2006 estimate of 37,552 MW. Figure III-11 displays a breakdown of resource contribution by reliability regions.

The three regions that represent the largest portion of national total peak load reduction potential are the RFC (27 percent) followed by MRO (23 percent) and SERC (17 percent). Given that peak loads vary significantly among reliability regions, it is also useful to characterize the existing demand response potential capability relative to each region's summer peak demand. Regional estimated peak load reduction potential from demand response programs ranges from three to 20 percent of 2008 regional peak load forecasts. Potential peak load reduction as a percentage of forecasted peak demand is the largest in MRO.

[82] NERC 2008 Summer Assessment.

Figure III-11. Estimated potential peak load reduction by demand response resources by region and customer class

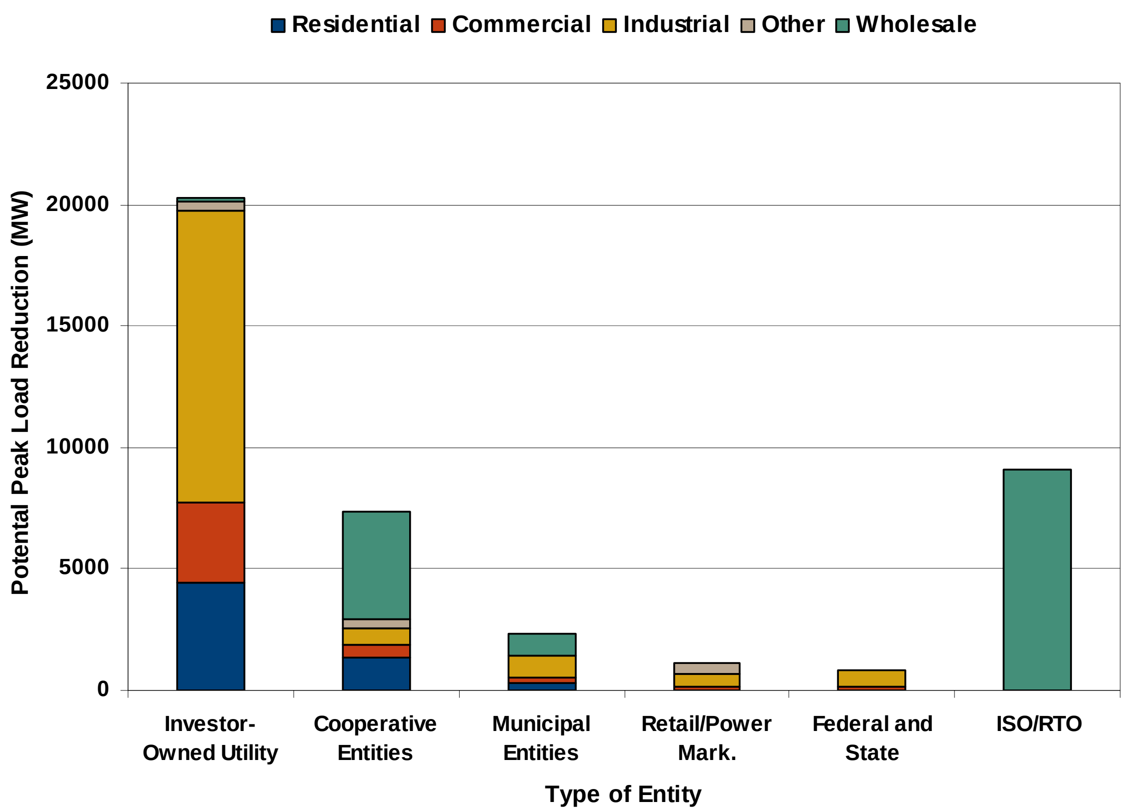


As Percent of Projected Summer 2008 Peak Demand	**4.4%**	**6.7%**	**20.2%**	**9.4%**	**5.6%**	**3.2%**	**3.2%**	**3.0%**	**N/A**

Source: 2008 FERC Survey
Note: Other includes ASCC and Hawaii.

By type of survey respondent, the estimated nationwide potential peak load reduction closely matches the pattern observed in the 2006 FERC Survey. Investor-owned utilities comprise the largest fraction; and their incentive-based demand response programs and time-based rates account for 20,267 MW (50 percent) of estimated nationwide potential peak load reduction (see Figure III-12). Cooperative entities account for 7,364 MW, or 18 percent of total national potential peak load reduction, and municipal entities and federal and state utilities account for 1,881 MW, or five percent.

Figure III-12. Estimated potential peak load reduction by demand response resources, by type of entity and customer class



Source: 2008 FERC Survey

Chapter IV. Demand Response Developments

This chapter reviews activity on demand response at the national and state level. It describes FERC's efforts at the wholesale level to ensure that demand response resources are treated comparably to supply resources; discusses other factors that affect demand response programs; relays some of the significant ways in which demand response was used in the past year; provides a description of developing demand response issues; and describes recent and new demand response pilot projects. In doing so, it addresses the fourth and fifth areas Congress directed the Commission to consider in EPAct section 1252(e)(3):

(D) the potential for demand response as a quantifiable, reliable resource for regional planning purposes; and

(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.

FERC Actions to Ensure Comparable Treatment of Demand Response Resources

At the wholesale level, FERC recognizes the important role that demand response plays in ensuring the competitiveness of wholesale markets and the reliability of grid operations. FERC continues to assess and monitor the wholesale markets under its jurisdiction to ensure that demand response resources that are technically capable of providing a service are treated comparably to supply resources offering that service. This subsection discusses the key demand response-related actions that FERC has taken since the 2007 FERC Demand Response Report.

Demand Response Participation in RTO and ISO Wholesale Markets

FERC regulates six independent system operators (ISOs) and regional transmission organizations (RTOs):[83] ISO New England, Inc. (ISO-NE), New York Independent System Operator, Inc. (NYISO), PJM Interconnection, Inc. (PJM), Midwest Independent Transmission System Operator, Inc. (Midwest ISO), SPP, and the California ISO. Since the 2007 FERC Demand Response Report, FERC has taken several actions concerning the participation of demand response in the wholesale markets operated by these ISOs and RTOs.

FERC actions with regard to individual ISOs and RTOs include the following:

Midwest ISO: FERC conditionally accepted the Midwest ISO's proposal to implement a day-ahead and real-time ancillary services market. The market design provides for the integration of demand response resources into reserves markets and includes scarcity-pricing provisions

[83] Independent System Operators grew out of Orders Nos. 888/889 where the Commission suggested the concept of an Independent System Operator as one way for existing tight power pools to satisfy the requirement of providing non-discriminatory access to transmission. Subsequently, in Order No. 2000, the Commission encouraged the voluntary formation of Regional Transmission Organizations to administer the transmission grid on a regional basis throughout North America (including Canada). Order No. 2000 delineated twelve characteristics and functions that an entity must satisfy in order to become a Regional Transmission Organization.

that should encourage demand response to participate.[84] FERC also conditionally accepted the Midwest ISO's resource adequacy program, which contains mandatory requirements for any market participant serving load in the Midwest ISO region to have and maintain access to sufficient planning resources. The program provides that the resource adequacy requirement can be met by any qualified planning resources, be they generation capacity or demand response.[85]

NYISO: FERC conditionally accepted NYISO's proposal to allow certain demand response resources to offer operating reserves and regulation service into the NYISO-administered markets, provided they install real-time metering and meet certain performance criteria and technical specifications comparable to those required of generation resources. FERC required NYISO to provide information on the progress of the ongoing process to accommodate batch loads and energy storage technologies in providing operating reserves and regulation service.[86]

California ISO: FERC continues to monitor the California ISO's efforts to integrate demand response resources into its markets.[87] Demand response resources meeting certain requirements can currently participate in the California ISO's energy and ancillary services markets as Participating Load.[88] In compliance with a prior FERC order,[89] the California ISO filed its first annual demand response report in January 2008.[90] Additionally, the California ISO has engaged in a stakeholder process to enhance opportunities for demand response resources to participate in the California ISO's markets after the initial release of its market redesign and technology update (MRTU) program. The California ISO intends to allow demand response resources to bid into the California ISO energy markets and provide certain ancillary services.[91]

SPP: FERC continues to monitor SPP's efforts to integrate demand response resources into its energy imbalance services market.[92] SPP filed two status reports in 2007 regarding its progress in implementing demand response. In its August 1, 2007 filing, SPP discussed how its market design currently accommodates behind-the-meter wholesale generation.[93] SPP also reported that it has a three-year commitment with the Electric Power Research Institute to explore best practices of demand response and energy efficiency. On February 4, 2008, SPP filed a follow-up report, stating that it was working on market design issues that needed to be resolved in order to enable demand response to participate directly in the energy imbalance services market. In order to discuss ways to break down implementation barriers, SPP hosted a Demand Response Educational Forum on July 27 and July 28, 2008.

PJM and ISO-NE: In PJM, FERC responded to a complaint challenging the sunset of an incentive program for demand response. FERC also acted to address concerns about potential

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[84] *Midwest Indep. Transmission Sys. Operator, Inc*., 122 FERC ¶ 61,172 (2008).

[85] *Midwest Indep. Transmission Sys. Operator, Inc*., 122 FERC ¶ 61,283 (2008).

[86] *New York Independent System Operator, Inc*., 123 FERC ¶ 61,203 (2008).

[87] See *Cal. Indep. Sys. Operator Corp*., 119 FERC ¶ 61,313 at P 226 (2007).

[88] See CAISO FERC Electric Tariff, Third Replacement Volume No. I, Sheet No. 27A and Appendix B.4, Participating Load Agreement.

[89] *Cal. Indep. Sys. Operator Corp*., 119 FERC ¶ 61,313 at P 226 (2007).

[90] CAISO First Annual Report Evaluating Demand Response, FERC Docket No. ER06-615-018 (Jan. 25, 2008).

[91] See CAISO Straw Proposal: Post-Release 1 MRTU Functionality for Demand Response (Nov. 9, 2007).

[92] See *Southwest Power Pool, Inc*., 114 FERC ¶ 61,289, at P 229 (2006).

[93] SPP's August 1, 2007 filing in FERC Docket No. ER06-451-024.

gaming in the demand response programs in PJM and ISO-NE. Each of these orders is discussed later in this section.

On October 17, 2008, FERC issued its Wholesale Competition Final Rule that recognized the importance of demand response in ensuring just and reasonable wholesale prices and reliable grid operations. The Commission, as part of the Final Rule, requires all RTOs and ISOs to:

(1) accept bids from demand response resources in their markets for certain ancillary services, comparable to other resources, unless the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate;
(2) eliminate during a system emergency a charge to a buyer in the energy market for taking less electricity in the real-time market than purchased in the day-ahead market;
(3) permit aggregators of retail customers to bid demand response on behalf of retail customers directly into the organized energy market, unless the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate;
(4) modify their market rules, as necessary, to allow the market-clearing price during periods of operating-reserve shortage to reach a level that rebalances supply and demand so as to maintain reliability while providing sufficient provisions for mitigating market power; and
(5) study whether further reforms are necessary to eliminate barriers to demand response in organized markets.[94]

EISA 2007 Directs National Assessment and a National Action Plan

Section 529 of EISA 2007 requires FERC to complete a National Assessment of Demand Response within 18 months of enactment. The Assessment must estimate demand response potential in five and ten year horizons and determine how to overcome the barriers to achieving that potential. Within one year after completion of the Assessment, FERC must complete a National Action Plan on Demand Response that: 1) identifies the requirements for technical assistance to states; 2) designs and identifies the requirements for a national communications program; and 3) develops or identifies analytical tools, model regulatory provisions, and model contracts for use by customers, states, utilities, and demand response providers. FERC is tasked with developing the Plan with the participation of a broad range of industry, state utility commission, and non-governmental stakeholders. Six months after completion of the Plan, FERC and the Department of Energy must submit to Congress a proposal for implementing the Plan.

Regional Transmission Planning Processes

Incorporating demand response resources and other technologies into planning horizons and load forecasts allows transmission providers to depict more accurately the energy needs of their areas, thereby potentially deferring or offsetting costly investments in new peaking generation or even transmission. In addition, greater demand response can minimize congestion, increase efficiency within markets, and enhance reliability of the system. Realizing these potential benefits, FERC addressed demand response resources in its Order No. 890, which reformed the open-access

[94] Wholesale Competition in Regions with Organized Electric Markets, Order No. 719, 73 Fed. Reg. 64,100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 61,071 (2008) (Order No. 719).

transmission tariffs (OATTs) of FERC-jurisdictional transmission providers.[95] Order No. 890 required transmission providers to establish a coordinated, open, and transparent transmission planning process that complies with certain principles, including comparability,[96] and that allows for the incorporation of demand response resources if they "are capable of providing the functions assessed in a transmission planning process, and can be relied upon on a long-term basis."[97]

Each transmission provider was required to either submit (as a new attachment, "Attachment K", to its OATT) a proposal for a coordinated and regional planning process that complies with the Order No. 890 principles, or make a compliance filing describing its existing planning process and how it is consistent with or superior to the requirements in Order No. 890. As a means of assisting transmission providers in complying with the requirements of Order No. 890, FERC held regional technical conferences to discuss implementation issues as well as ensure sufficient participation among customers and stakeholders. Additionally, FERC staff published a White Paper outlining the primary processes, criteria, and issues that should be addressed within the Attachment K.[98]

Filings by transmission providers were due on December 7, 2007. On December 27, 2007, FERC issued a rehearing order, Order No. 890-A, providing additional guidance as to how the transmission provider can achieve compliance with the comparability principle. Specifically, Order No. 890-A stated that the transmission provider needed to identify as part of its Attachment K planning process "how it will treat resources on a comparable basis and, therefore, should identify how it will determine comparability for purposes of transmission planning."[99]

In general, transmission providers' compliance filings detailed how their previously established planning processes satisfied the nine principles in Order No. 890. For instance, South Carolina Electric & Gas Company participates in the South Carolina Regional Transmission Planning process, and under this regional process coordinates with interconnected systems to identify system enhancements that could relieve congestion. Other transmission providers such as Tucson Electric Power and Portland General Electric highlighted the various sub-regional and regional planning groups and reliability councils they take part in or follow, and explained how these processes encourage open participation, comparability, and active involvement from all interested stakeholders throughout the planning cycle.

Many of the filed Attachment Ks stated that demand response and other non-traditional alternatives to transmission were incorporated into the planning processes at the outset through various load forecasts and planning horizons. Only a few filed Attachment Ks stated that demand response resources are explicitly examined as part of the planning process or as alternatives to transmission. Some transmission providers highlighted specific methods or processes relating to their treatment of demand response and demand response resources:

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[95] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 FR 12,266 (March 15, 2007), FERC Stats. & Regs. ¶ 31,241 (2007), order on reh'g, Order No. 890-A, 73 FR 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶31,261 (2007).

[96] The other principles are coordination, openness, transparency, information exchange, dispute resolution, regional participation, economic planning studies, and cost allocation.

[97] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 479.

[98] Order No. 890 Transmission Planning Process Staff White Paper, Aug. 2, 2007, filed in Docket Nos. RM05-25-000 and RM05-17-000.

[99] Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 216.

- PJM seeks to determine what level and type of demand response would alleviate the need for a transmission upgrade to relieve congestion. That information is then made available to the Transmission Expansion Advisory Committee as well as the public.
- NorthWestern Energy requires load-serving entities, point-to-point, and network transmission customers to submit information on any demand response resource, demand reduction, conservation and demand-side management, demand response resource savings, conservation savings, and other customer load-reduction alternatives that would reduce or alter their load forecasts.
- Southern Company permits demand response resource and demand-side management stakeholders to have voting rights in its regional planning stakeholder process.
- PacifiCorp permits transmission customers to ask for studies of the ability of demand response resources not otherwise included in the transmission plan to reduce the overall cost of reliably serving the forecasted needs of the transmission provider and its transmission customers.

FERC has found that some of the filed Attachment Ks adequately describe how demand response resources will be comparably treated. For example, FERC concluded that the California ISO's filing provided an adequate explanation, noting that the tariff made explicit that: 1) demand response programs that are proposed for inclusion in the base case for the transmission plan or as alternatives to transmission upgrades will be considered in the transmission plan if timely proposed; 2) timely proposed demand response programs and generation projects will be subject to the same screening criteria as other projects; 3) demand-side management and interruptible loads will be considered as alternatives to transmission upgrades when the California ISO is considering reliability-related projects; and 4) the California ISO must consider the costs and benefits of viable alternatives to proposed transmission projects designed to relieve congestion, including demand-side management programs.[100] In recognition that Order No. 890-A was not issued until after the due date for filing Attachments Ks, FERC has directed other transmission providers to make a further compliance filing providing the necessary details required by Order No. 890-A. FERC has noted, for example, that tariff language should provide for participation throughout the transmission planning process by sponsors of transmission solutions, generation solutions, and solutions utilizing demand response.[101]

Other Factors That Affected Demand Response Programs

In the year since the 2007 FERC Demand Response Report, numerous developments have affected demand response programs. These developments suggest that such programs are likely to increase. Chief among these is the continued promotion of demand response by states, utilities' increased interest in demand response at the retail level, continued cross-jurisdictional coordination, and the increased activities of third-party demand response aggregators.

States Increase their Focus on Demand Response

Since the 2007 FERC Demand Response Report, numerous states have worked to promote greater demand response. Examples of these state initiatives include:

[100] *Cal. Indep. Sys. Operator, Inc.*, 123 FERC ¶ 61,283 at P 106 (2008).
[101] See, *e.g.*, Tampa Electric Company, 124 FERC ¶ 61,026 at P 42 (2008).

Alabama: The Alabama Public Service Commission, following a two-year residential critical peak pricing pilot by Alabama Power Company, approved making the critical peak pricing option available for residential customers with AMI on a non-experimental basis.[102]

California: The California Public Utilities Commission has worked to expand the dynamic pricing programs offered by the three large California investor-owned utilities. The Commission has approved San Diego Gas & Electric Company's proposal for default critical peak pricing for commercial and industrial customers and its peak-time rebate program for residential customers.[103] The Commission has also established a schedule for phasing in similar dynamic rates in Pacific Gas and Electric's service area,[104] and is reviewing a dynamic pricing proposal by Southern California Edison. Additional California initiatives are discussed later in this section.

Colorado: In June 2008, the Colorado Public Utilities Commission set energy savings goals that call for Xcel Energy to help customers reduce their electricity use in 2020 by about 11.5 percent and reduce peak demand by 944 MW, from programs implemented during 2009-2020. The Colorado Public Utilities Commission is allowing Xcel Energy to earn a profit tied to the energy savings achieved and net economic benefits of the programs, which could be as much as 20 percent of utility program expenditures.[105]

Mid-Atlantic States: Load growth and transmission congestion in the Mid-Atlantic region have focused lawmakers' and regulators' attention on demand response and energy efficiency as critical tools for ensuring near-term adequate and reliable supplies of electricity. In Maryland, for example, PJM has testified that forecasted peak demand in the state may exceed the supply of electricity that could be imported over the existing transmission lines if certain transmission projects are not in service by 2011.[106] In April 2008, Maryland Governor O'Malley signed into law the EmPower Maryland Energy Efficiency Act of 2008. The law requires each electric company to implement a cost-effective demand response program in the electric company's service territory that is designed to achieve a reduction in per capita peak electricity consumption of at least five percent by the end of 2011, ten percent by 2013, and 15 percent by 2015.[107] The Public Service Commission of Maryland has directed all electric companies to develop and file comprehensive energy efficiency, conservation and demand reduction plans to meet these goals.[108]

Similarly, in April 2008, New Jersey released a draft Energy Master Plan to address the state's electricity and heating challenges. One of the goals is to reduce peak demand for electricity by 5,700 MW by 2020. New Jersey proposes to: (1) expand real-time pricing for large commercial and industrial customers; (2) expand incentives for participation in regional demand response programs; (3) evaluate strong "inverted tariff" pricing system for residential

[102] Alabama Public Service Commission, Order in Docket No. U-4732 (May 13, 2008).

[103] California Public Utilities Commission, Opinion Addressing the Application and the Motion to Adopt the All Party and All Issue Settlement, Decision 08-02-034 (Feb. 28, 2008).

[104] California Public Utilities Commission, Decision Adopting Dynamic Pricing Timetable and Rate Design Guidance for Pacific Gas and Electric Company, Decision 08-07-045 (July 31, 2008).

[105] *Colorado PUC Adopts New Goals and Incentives for Utility Energy Efficiency Programs*, June 2008, Southwest Energy Efficiency Project, http://www.swenergy.org/news/index.html.

[106] Maryland Public Service Commission, Case 9117, Phase II, testimony of Michael Kormos, Oct. 2007, 3-4.

[107] H.B. 374, 2008 Leg., Reg. Sess. (Md. 2008).

[108] Maryland Public Service Commission, Order No. 81637, Sept. 28, 2007, 1.

customers; (4) move the state's electricity grid toward the development of a "smart grid" infrastructure; and (5) monitor the results of all demand response initiatives through 2011 to determine the most effective mix of actions to achieve long-term peak demand reduction goals.[109]

Illinois: On August 28, 2007, Illinois Governor Blagojevich signed legislation requiring utilities to ramp up energy efficiency and demand response programs to meet annual electricity consumption reduction goals that start at 0.2 percent the first year and increase to two percent by 2015.[110] On January 14, 2008, the Illinois Commerce Commission approved programs submitted by Commonwealth Edison Company and the three Ameren Illinois electric utilities in compliance with the law.[111]

Maine: The Maine Public Utilities Commission commissioned a study of the potential for incremental demand response in Maine. The study recommended that Maine combine energy efficiency with demand response, investigate more stringent appliance standards, and increase program funding and certainty.[112]

Ohio: On May 1, 2008, Ohio Governor Strickland signed into law Senate Bill 221. Among the elements included in the bill are energy-efficiency program requirements that can include demand response programs, customer-sited programs, and transmission and distribution infrastructure improvements that reduce line losses. Beginning in 2009, an electric distribution utility must implement peak demand reduction programs designed to achieve a 1 percent reduction in peak demand in 2009 and an additional 0.75 percent reduction each year through 2018.[113]

Demand Response in Reaction to Peak Load Growth and Rising Energy Prices

Even in the absence of state regulatory requirements to do so, numerous utilities have taken action since the 2007 FERC Demand Response Report to expand their retail demand response programs. One motivating factor for many of these utilities has been concern about peak load growth. Examples include:

- Rocky Mountain Power continues to expand its demand-side management programs in Utah in response to high load growth and the cost of building and operating new peaking generation. In Wyoming, Rocky Mountain Power proposed in January 2008 to implement six demand-side management programs, budgeted at $34 million, modeled on its successful demand-side management programs in Utah.[114]
- Sierra Pacific Power Company and Nevada Power Company are testing several types of demand response technologies including controllable thermostats in addition to expanding

[109] New Jersey, Draft New Jersey Energy Master Plan, April 2008, 56-57.

[110] Illinois Senate Bill 1592.

[111] ICC press release, *available at*http://www.icc.illinois.gov/downloads/public/Energy%20Efficiency%20Plan%20release1%202-6-08.doc.

[112] Synapse Energy Economics, Inc., Increasing Demand Response in Maine, January 2008, 1, 26-30.

[113] S.B. 221, 127th Gen. Assem., Reg. Sess. (Ohio 2008).

[114] *Rocky Mountain Power Proposes DSM Programs in Wyoming*, January 2008, Southwest Energy Efficiency Project, http://www.swenergy.org/news/index.html.

their peak power generation in order to meet future load growth in Nevada.[115] The Public Utilities Commission of Nevada has approved Sierra Pacific Power Company's request to increase its demand-side management funding to $10 million per year for 2008 through 2010 and Nevada Power Company's request to increase its demand-side management funding to $44 million for 2008 and $47 million for 2009.[116]

- Hawaiian Electric Company is pursuing demand response in the context of tight generation reserves and the prospect of new generation not coming into service until 2009. The company has developed its Energy Scout program that pays incentives for businesses who agree to reduce demand during system emergencies.[117]
- The Indiana State Utility Forecasting Group has observed that utilities in Indiana have a "renewed interest" in demand response, because "as system-wide demand grows, the utilities face more immediate need for new resources" and demand response programs "are more likely to be cost-effective if the avoided cost of new supply-side resources enters the equation."[118]

Cross-Jurisdictional Coordination on Demand Response Continues

Multi-state groups, including the Midwest Demand Resources Initiative (MWDRI), the Mid-Atlantic Distributed Resources Initiative (MADRI), and the Pacific Northwest Demand Response Project continue to coordinate across jurisdictions to enhance demand response. For example, MWDRI, along with the Regulatory Assistance Project,[119] conducted a study to: 1) identify the potential capacity and energy cost savings and avoided generation due to demand and energy reductions in the Midwest ISO; 2) identify impacts on emissions from demand and energy reductions; and 3) allocate benefits of demand reductions to states and regions and demonstrate merits of regional cooperation.[120] MWDRI also worked with Chuck Goldman from the Lawrence Berkeley National Laboratory to conduct the Midwest Retail Demand Response Program Survey, the results of which were released on March 7, 2008. The primary purpose of the survey was to address the lack of a comprehensive comparative summary of demand response assets in the Midwest ISO footprint. The results are summarized in Table IV-1:

[115] Sierra Pacific Resources 2007 Q3 Company Earnings Conference.

[116] *Sierra Pacific Power Receives Approval to Expand DSM Programs, Nevada Power Files for Program Expansion," December 2007 and "Nevada PUC Approves Expanded DSM Programs*, March 2008, Southwest Energy Efficiency Project, http://www.swenergy.org/news/index.html.

[117] Direct Load Control Program for Businesses, Hawaii Electric Company brochure, http://www.heco.com/portal/site/heco/menuitem.508576f78baa14340b4c0610c510b1ca/?vgnextoid=cd9cea991c3ad010VgnVCM1000005c011bacRCRD&vgnextchannel=a0b9f2b154da9010VgnVCM10000053011bacRCRD&vgnextfmt=default&vgnextrefresh=1&level=0&ct=article.

[118] Indiana State Utility Forecasting Group, Report on Indiana Electricity Projections, at p. 4-5 (2007) *available at:* http://www.purdue.edu/dp/energy/pdfs/SUFG/2007SUFGforecast.pdf.

[119] The Regulatory Assistance Project is a non-profit organization, formed in 1992 that provides research, analysis, and educational assistance to public officials on electric utility regulation. See http://www.raponline.org.

[120] See http://www.misostates.org/PresentationDraft1-1d.ppt.

Table IV-1. Results of Midwest retail demand response program survey

MISO Members		Non-MISO Members	
3,649 MW		757 MW	
Interruptible Tariffs	Economic Programs	Direct Load Control	Total Potential Reductions
3,397 MW	154 MW	855 MW	4406
Winter Only	Summer Only	Summer and Winter	Year-Round
4	31	5	82

Source: Presentation by Chuck Goldman, Lawrence Berkeley National Laboratory at MDWRI Meeting, March 7, 2008, available at http://www.misostates.org/_borders/2GoldmaniPresentation.pdf.

In 2007, PJM drafted a Demand Response Roadmap to facilitate coordination between retail and wholesale markets. The Demand Response Roadmap outlines nine top priority opportunities for stakeholders. In May 2008, PJM held its second Demand Response Symposium and participants focused on three topic areas: data management and automatic metering infrastructure, demand response customer education and training, and coordinating demand response with transmission planning and capacity auction processes.[121]

The National Association of Regulatory Utility Commissioners-FERC (NARUC-FERC) Collaborative Dialogue on Demand Response continues its work to coordinate state and federal efforts. The Collaborative is in the process of developing a research report to identify regulatory and market barriers that limit participation in demand response and outline options to coordinate retail and wholesale regulatory policies that would reduce or eliminate barriers and stimulate greater participation in demand response. Initial results from this effort were presented at two meetings of the National Association of Regulatory Utility Commissioners in 2008.[122]

Use of Third-Party Aggregators Continues to Expand

Third-party aggregators can provide an important opportunity for consumers who would otherwise be unable to participate in demand response programs. As Figure IV-1 demonstrates, PJM has seen a continued increase in activity by aggregators.

Examples of the increase in activity by aggregators since the 2007 FERC Demand Response Report include:

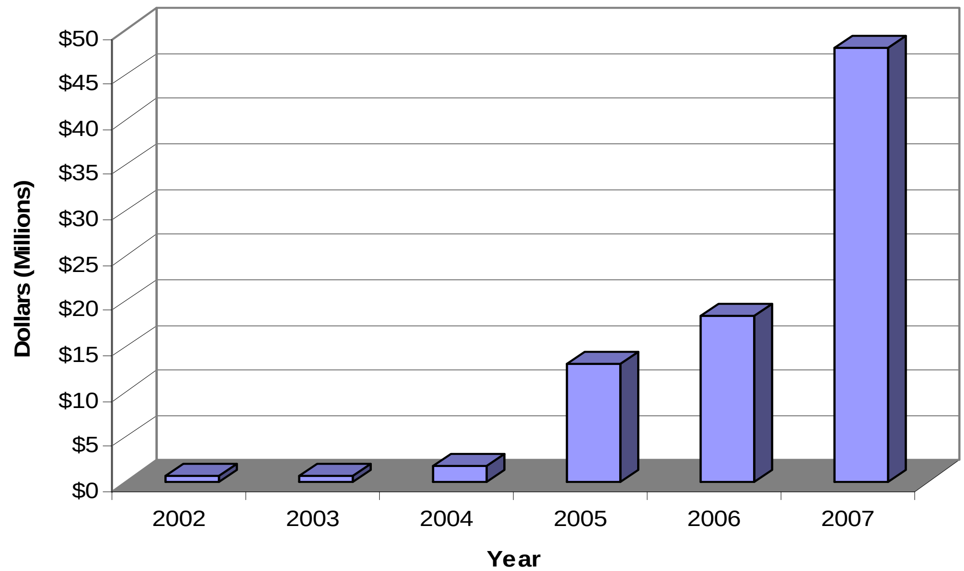
- Energy Curtailment Specialists and Kansas City Power & Light announced a contract for a demand response partnership.[123]
- EnerNOC officially entered the Texas market by participating in the emergency demand response program administered by ERCOT and is partnering with local area businesses.[124]

[121] The proceedings of the May 12-13, 2008 Symposium can be found at http://www.pjm.com/committees/stakeholders/drs/drs.html.

[122] See, for example, http://www.narucmeetings.org/Presentations/v6%20kema%20presnew.pdf.

[123] See http://www.ecsdemandresponse.com/kc_press_release_oct2.php.

Figure IV-1. Annual energy payments to curtailment service providers for economic activity in PJM



Source: Presentation by Susan Covino, PJM at National Town Hall Meeting on Demand Response, June 3, 2008.

- Comverge, Inc. entered into a contract with Southern Maryland Electric Cooperative to provide up to 75 megawatts of capacity from residential, small commercial, large commercial, and industrial consumers.[125]
- Each of the three investor-owned utilities in California has entered into contracts with several third-party aggregators.[126]

Demand Response Played a Critical Role during Emergencies

Since the 2007 FERC Demand Response Report, demand response has proven useful not only in meeting peak load but also in responding to other system emergencies.

Demand Response Helped Meet Peak Load

During 2007, the use of demand response proved necessary to the reliable operation of electricity markets during peak hours in several regions.

California: California experienced a heat wave from August 29, 2007 through August 31, 2007. Although the system peak load of 48,515 MW occurred on August 31, the most severe day for California ISO grid operators was August 29, when a stage 1 emergency was declared

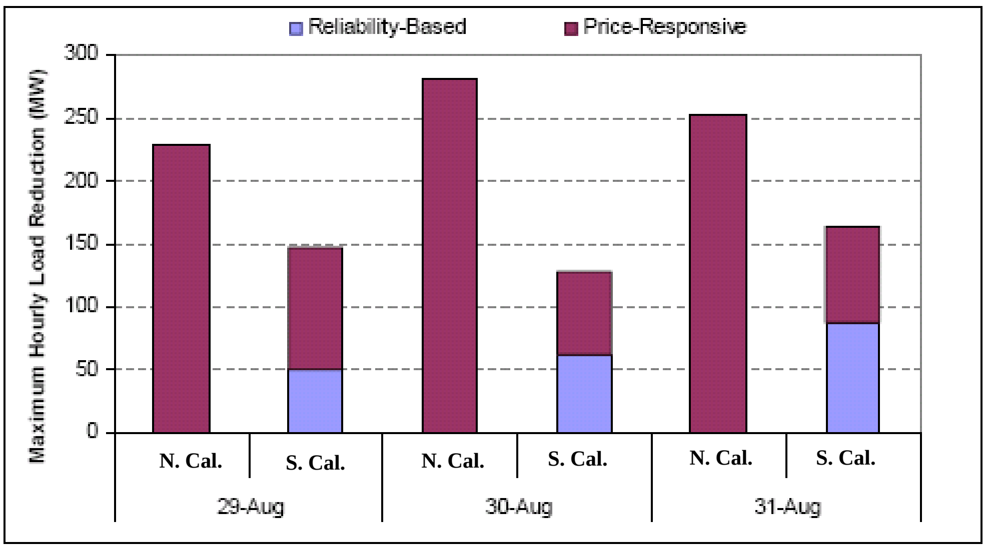
[124] EnerNOC press release, http://www.enernoc.com/press/pr_080313.htm.

[125] Energy Central news release, April 2008 http://www.energycentral.com/centers/news/daily/article.cfm?aid=10152933.

[126] See, *e.g.*, *EnergyConnect receives approval to provide demand response services to SCE*, March 24, 2008, http://www.datamonitor.com/industries/news/article/?pid=4E28F3EC-CE45-4439-B24A-8C7C59F23D04&type=NewsWire.

and a stage 2 was forecast as probable.[127] A loss or curtailment that day of 550 MW of generation capacity in the south threatened operating reserves, but a stage 2 emergency was averted with the assistance of demand response in the Pacific Gas and Electric Company service territory. Loads were forecast to be even higher on August 30, and stage 1 and stage 2 emergencies were predicted but not realized as actual load peaked almost 2,000 MW below the hour-ahead forecast due in part to conservation calls and utility-triggered demand response.[128] The state of California runs a voluntary program called the Stage 1 Flex Alert program in which the state makes public announcements requesting consumers to reduce demand whenever the California ISO declares a stage 1 emergency. With respect to that program, the California ISO reported that consumers voluntarily achieved approximately 1,000 MW in conservation on August 30.[129] As shown in Figure IV-2, the utility-triggered demand response came from both reliability-based programs and economic programs.[130]

Figure IV-2. Investor-owned utility demand response reductions in California during the heat wave of Aug 29-31, 2007



Source: California ISO 2007 Annual Report on Market Issues and Performance at p. 2.6 (April 2008).

Virginia and the Mid-Atlantic Region: PJM reached its 2007 system peak of 139,428 MW on August 8, 2007. On that day, 2,155 MW were enrolled in the reliability-based emergency demand response program and 2,498 MW were enrolled in the economic demand response

[127] A stage 1 emergency occurs when operating reserves fall below 7% of demand. A stage 2 emergency occurs when operating reserves fall below 5%.

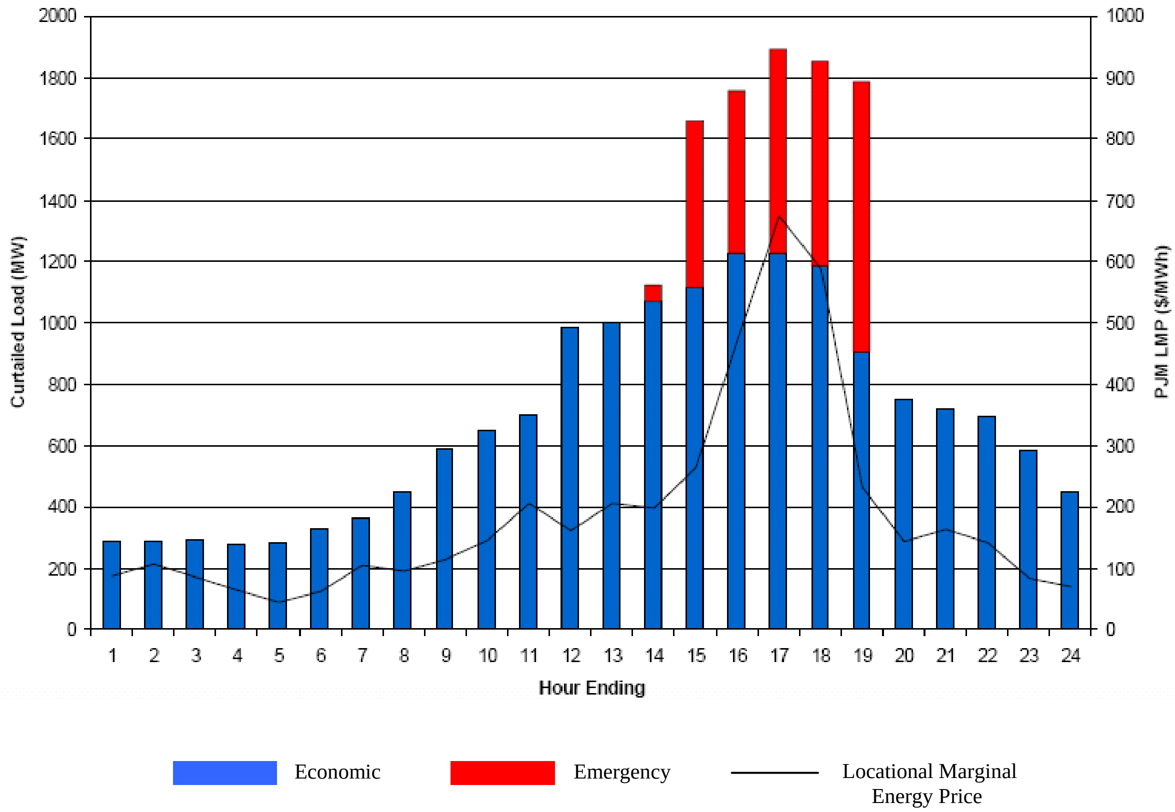
[128] See CAISO Market Performance Report August 2007 at p. 8 (Sep. 24, 2007).

[129] See California ISO Thanks Californians for Conservation, CAISO News Release (Sep. 4, 2007).

[130] Reliability-based demand response programs are programs that are activated during system emergencies or to maintain local or system reliability. These programs include emergency demand response programs, capacity market programs, direct load control, interruptible/curtailable rates, and ancillary services market programs. Economic demand response programs encourage customers to reduce load when prices are high. These programs include critical peak pricing retail tariffs in which program participants are charged significantly higher rates for peak hours of declared critical peak days. They also include various price-based programs where customers are paid to reduce consumption when certain market conditions are triggered.

program.[131] PJM invoked its emergency demand response program in the Mid-Atlantic region and Virginia between 3 p.m. and 6 p.m.[132] Demand response resources in that program provided 888 MW of reduction, 23 MW more than they had committed.[133] Demand response resources in the economic program provided additional reductions as shown in Figure IV-3:

Figure IV-3. Demand response in PJM on August 8, 2007



Source: PJM, Demand Side Response Weekly Overview & Long Term Trend Report Week of 8/6/2007 to 8/10/2007, available at www.pjm.com/committees/working-groups/dsrwg/postings/weekly-overview-long-term-trend-report.pdf.

New York: Twice during summer 2007, NYISO activated its new Targeted Demand Response Program, which allows NYISO to call upon certain demand response resources in select locations within New York City. The July 19, 2007 activation resulted in a reduction of 44 MW; the August 3, 2007 activation resulted in a reduction of 55 MW.[134]

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[131] PJM, 2007 State of the Market Report, March 2008 at 4.

[132] *Id.* at 91.

[133] *Id.* at 91-92.

[134] NYISO, Summer 2007 Electricity Review at 9 (Oct. 2007).

Demand Response Was Used to Deal with Other Reliability Events

In Texas, demand response proved critical to addressing sudden changes in generation output on two occasions. On December 12, 2007, ERCOT deployed its Load Acting as Resource program (LaaRs) in response to a drop in generation.[135] Specifically, 1,022 MW of generation tripped and within 10 minutes of notice, LaaR providers responded with a 1,051 MW curtailment to stabilize the grid. Then on February 26, 2008, ERCOT implemented Step Two of its Emergency Electric Curtailment Plan[136] after a combination of declining wind generation, increased heating demand, and lower-than-expected generation from several non-wind plants led to a frequency drop. ERCOT reported that the response of LaaRs to deployment was generally good, with 1,108 MW of LaaR load responding within 10 minutes. Only two LaaR providers failed to deploy within 10 minutes. The deployment of LaaRs halted the frequency decline and restored ERCOT to stable operation.

Demand Response Resources Played a Significant Role in Capacity Markets

Demand response resources participated in capacity markets in PJM and ISO-NE.

> *PJM*: PJM's Reliability Pricing Model (RPM) provides regular auctions for those load-serving entities who have not met their capacity needs through self-supply or bilateral contracts. Since the 2007 FERC Demand Response Report, PJM has held RPM auctions for the 2010 to 2011 planning year and the 2011 to 2012 planning year. For the 2010/2011 auction, of the 133,093 MW that competed, 968 MW came from demand response resources; and of the 132,191 MW that cleared in the auction, 939 MW came from demand response resources.[137] For the 2011/2012 auction, of the 137,720 MW that competed, 1,652 MW came from demand response resources; and of the 132,222 MW that cleared in the auction, 1,365 MW came from demand response resources.[138] By comparison, the RPM auction for 2008-2009 cleared 536 MW of demand response. As displayed in Figure IV-4, demand response resources have provided a significant portion of the new capacity contracted through the RPM auctions.
>
> *ISO-NE*: ISO-NE held its first Forward Capacity Market (FCM) auction in February 2008. Like PJM's RPM, FCM is designed to procure enough capacity to meet ISO-NE's forecasted demand and reserve requirements three years in the future and to provide a long-term commitment to resources to encourage investment. Supply- and demand-side resources, including energy efficiency, are eligible to participate in the FCM.[139] In ISO-NE's first FCM auction, 39,155 MW of qualified new and existing demand-and supply-side resources

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[135] See http://www.ercot.com/meetings/dswg/keydocs/2008/0111/LaaR_Deployment_12-12-07.pdf. LaaRs is an interruptible program operated by ERCOT in which customers may qualify to provide operating reserves.

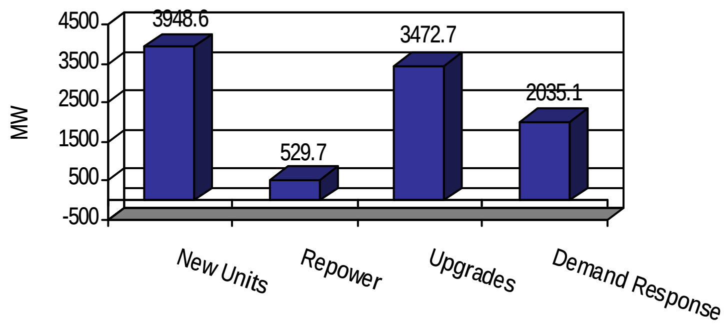
[136] ERCOT's Emergency Electric Curtailment Plan is the detailed, step-by-step procedure to maximize generation resources during grid emergencies. For more information, see http://www.ercot.com/news/presentations/2007/ERCOT_Emergency_Procedures_%28EECP%29_Background.doc.

[137] PJM, 2010/2011 RPM Base Residual Auction Results, February 2008, 4.

[138] PJM, 2011/2012 RPM Base Residual Auction Results, May 2008, 6.

[139] ISO-NE, *Introduction to Demand Resource Participation in New England's Forward Capacity Market*, February 2007, 8-9.

Figure IV-4. Cumulative increase in capacity resources over the first five RPM auctions (2007-2011)



Source: Presentation by Andrew Ott, PJM, available at http://www.narucmeetings.org/Presentations/OTT_MACRUC_June_2008.ppt.

competed to provide 32,305 MW of required capacity.[140] Demand resources represented a significant portion of the new resources that cleared in the auction. Approximately 1,813 MW of new capacity cleared the auction, and of that amount, about 1,188 MW came from new demand resources. In fact, almost twice as many new demand resources cleared (1,188 MW) compared to new supply resources (626 MW). As shown within Figure IV-5 below, nearly half of all new demand resources cleared in Massachusetts and demand response and energy efficiency led the way in type of demand resources that cleared the auction.[141]

As Demand Response Participation Expands, Debate Has Intensified

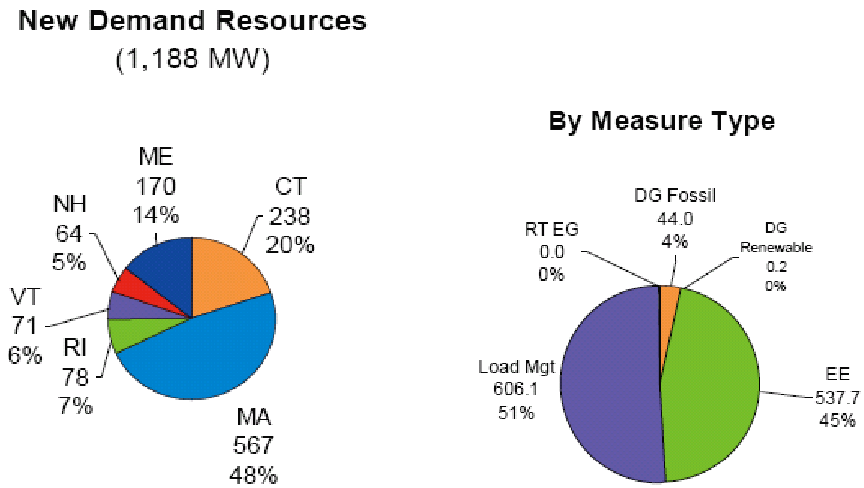
As demand response participation increases and as states consider additional means of increasing demand response, issues concerning consumer choice, compensation, and measurement and verification have received more attention.

Concerns about Consumer Choice and Appropriate Compensation

Automated demand response, in which end users' electrical systems or appliances respond directly to price or emergency signals without the need for human intervention, has generated questions about consumer choice. In November 2007, the California Energy Commission proposed energy efficiency building standards that would have required new buildings to install programmable communicating thermostats that allowed utilities to control the building's air conditioning or heating during emergencies. The thermostat requirement sparked considerable public opposition and legislative debate. On January 15, 2008, the California Energy Commission, emphasizing the importance of consumers' ability to opt out of demand response programs that involve programmable communicating thermostat, announced that it was dropping the requirement from the proposed

[140] Henry Yoshimura, *Demand Resource Results and Implications of the First Forward Capacity Market Auction*, May 2008, 3.
[141] *Id.* at 4-5, 11.

Figure IV-5. New demand resources by region and by measure type



Load Mgt=Demand response
80
RT EG=Distributed generation available during emergencies only
DG Fossil=Fossil-fueled distributed generation
DG Renewable=Renewable distributed generation
EE=Energy Efficiency

Source: Henry Yoshimura, *Demand Resource Results and Implications of the First Forward Capacity Market Auction,* May 2008, 3.

building standards but would continue the consideration of programmable communicating thermostats in its ongoing load management proceeding.[142] The California Energy Commission explained that the load management proceeding, which began on January 2, 2008 to explore tariff, equipment, software, automatic technologies and other measures appropriate to achieve a price-responsive electricity market,[143] would provide a better venue for a broader discussion of programmable communicating thermostat technology and how it could be used with future utility programs. Meanwhile, in May 2008, the Demand Response Research Center, following six years of research funded by the California Energy Commission, issued a communications standard for automated demand response systems in commercial and industrial facilities. The standard is designed to improve the reliability and cost-effectiveness of automating the response of buildings to standardized electricity price signals.[144]

Questions about the need for and appropriate level of incentives to ensure adequate demand response participation in wholesale markets have arisen. In PJM, the incentive payment to participants in the Economic Load Response Program (under which demand responders receive the full market-clearing price without a reduction for avoided generation and transmission charges when the price is at or above $75 MW/h) was set to expire on December 31, 2007. On November 20, 2007, the PJM Industrial Customer Coalition filed a complaint seeking to extend the incentive. The Commission denied the complaint, concluding that there was insufficient evidence to require PJM to continue the

[142] See http://www.energy.ca.gov/title24/2008standards/faq.html.

[143] California Energy Commission, Informational and Rulemaking Proceeding on Demand Response, Rates, Equipment and Protocols, Docket No. 08-DR-01 (Jan. 2, 2008).

[144] Demand Response Research Center, *Open Automated Demand Response Communication Standards* (May 2008), *available at* http://drrc.lbl.gov/openadr.

incentive portion of the program.[145] On May 21, 2008, FERC held a technical conference on demand response in organized wholesale markets that examined, among other topics, the issue of compensation. Little consensus on the issue developed, with some participants arguing that additional compensation is needed because there is insufficient participation by demand response resources, and other participants expressing concern about potential market inefficiencies when demand response resources are paid more than their marginal value of consuming the next MW of electricity.[146]

At the retail level, some states are re-examining the appropriate level of compensation for demand response. On June 25, 2008, the Connecticut Department of Public Utility Control opened an investigation of the cost-effectiveness of utility demand response and energy efficiency programs with a focus on increasing customer participation while ensuring that utilities remain within their budgets. One approach being considered is reducing customer incentive levels where appropriate.[147] In contrast, a Demand Response Working Group established by the New Jersey Board of Public Utilities has recommended supplementing existing PJM programs by offering additional incentives to increase the limited growth of demand response in New Jersey.[148]

Work Continues on Measurement and Verification

FERC has addressed concerns about measurement and verification in the wholesale markets. On February 5, 2008, ISO-NE made a tariff filing at FERC to prevent gaming by participants in its Day-Ahead Load Response Program, in which participants make day-ahead offers, subject to a minimum offer price, to reduce load in real time. According to ISO-NE, as fuel prices have increased, the minimum offer price is now below the market-clearing price the majority of the time. This development was alleged to have enabled customers to lock in artificially high customer baselines (*i.e.*, the level of consumption that would have occurred if the participant had not curtailed consumption), since baselines are calculated based on a 10-day rolling average excluding days on which a participant's demand response offer was accepted. FERC accepted ISO-NE's proposal to index the minimum offer price to fuel prices and noted that FERC's Office of Enforcement had begun a non-public investigation into whether any participants in the ISO-NE program had violated FERC rules.[149]

Similarly, PJM's Market Monitor has raised concerns about gaming. The current weekday PJM customer baseline methodology requires the selection of 10 weekdays and the five highest are used for the calculation, less low usage days and event days. In addition, there is no limit on the historical period that can be used to select the days. These provisions can result in an inflated estimate of what metered load would have been absent the reduction. In addition, there is no clear requirement that a customer had to take a verifiable step to reduce energy use in response to prices in order to receive payment under the program.[150] In June 2008, FERC conditionally accepted PJM's modification of the

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145 PJM Industrial Customer Coalition v. PJM Interconnection L.L.C., 121 FERC ¶ 61,315, P 29 (2007), reh'g pending.

146 FERC Technical Conference on Demand Response in Organized Markets, May 21, 2008.

147 Connecticut Department of Public Utility Control Order in Docket No. 07-10-03 (June 25, 2008).

148 Demand Response Working Group, Letter to Secretary Kristi Izzo of Board of Public Utilities, November 14, 2007.

149 ISO New England, Inc., 123 FERC ¶ 61,021 at P 1 and 25 (2008). In this order, the Commission cited ISO-NE's commitment to continue reviewing the matter in the stakeholder process and make a further filing by April 15, 2008. On June 13, 2008, FERC accepted a filing by ISO-NE to further modify the formula used to set the minimum offer price, lowering the heat rate index and, in turn, the minimum offer price. ISO New England Inc., 123 FERC ¶61,266 (2008).

150 PJM, 2007 State of the Market Report, March 2008, 108.

economic demand response measurement and verification rules to ensure that only those demand reductions that are made truly in response to price are compensated.[151] The filing also provided demand response resources greater flexibility to structure their bids to reflect their operating characteristics.

The North American Energy Standards Board (NAESB) continues its efforts on measurement and verification standards for demand response. NAESB has been working to identify best practices at both the retail and wholesale levels. On October 3, 2008, NAESB released a recommendation on proposed business standards for measurement and verification methodologies for comment.[152]

The California Public Utilities Commission is moving forward with its rulemaking to establish load impact and cost-effectiveness protocols for demand response.[153] On April 24, 2008, the California Public Utilities Commission adopted protocols for estimating the impact of demand response activities on electricity load.[154] The load impact protocols provide guidance both on ex-ante forecasting for planning purposes as well as ex-post evaluation to ensure fair compensation for demand response participants. The protocols identify the minimum data outputs needed and offer information on a range of available tools rather than mandating the use of any specific methods.

Demand Response Pilots Are Increasing

As stakeholders grapple with the issue of how to improve demand response, there has been a surge in pilot programs and demonstration projects, particularly involving Smart Grid technology. On April 21, 2008, the Department of Energy announced that it would be funding nine demonstration projects designed to reduce peak load demand by at least 15 percent using advanced technologies to integrate demand response with renewable energy, distributed generation, energy storage, and thermally activated technologies.[155]

Examples of recently completed or recently announced pilots include:

- *Oregon and Washington*: In December 2007, Pacific Northwest National Laboratory released the results of its year-long GridWise Demonstration Project on the Olympic Peninsula. The study found that advanced demand response technologies enable consumers to be active participants in improving power grid efficiency and reliability, while on average saving approximately ten percent on their electricity bills. The study also found that demand response technologies can help accommodate the variable nature of renewable resources, making it possible to more effectively manage their integration into the grid.[156] Also in Oregon, Portland General Electric, as a condition to installing two-way communicating smart

[151] PJM Interconnection, Inc., 123 FERC ¶ 61,257 (2008).

[152] See http://www.naesb.org/pdf3/dsmee100308w5.doc.

[153] California Public utility Commission, Rulemaking 07-01-041 (Order Instituting Rulemaking Regarding Policies and Protocols for Demand Response Load Impact Estimates, Cost-Effectiveness Methodologies, Megawatt Goals, and Alignment with the California Independent System Operator Market Design Protocols) (Jan. 31. 2007).

[154] Decision No. 08-04-050 (April 24, 2008).

[155] DOE press release, DOE Selects Projects for up to $50 Million of Federal Funding to Modernize the Nation's Electricity Grid, http://www.oe.energy.gov/news_room_and_events/1120.htm.

[156] *GridWise Demonstration Project Fast Facts*, Pacific Northwest National Laboratory, PNNL-SA-XXXXX (December 2007).

meters for its 805,000 residential and business customers, will be filing an experimental critical peak pricing tariff for approval by the Public Utility Commission of Oregon.[157]

- *New Jersey*: In August 2007, Public Service Electric and Gas Company completed its two-year residential time-of-use/critical peak pricing pilot in New Jersey. The pilot had two programs. Under one, participants were educated about the time-of-use tariff and notified of the critical peak pricing event on a day-ahead basis. Under the other program, participants were given a free thermostat that received price signals from the utility and adjusted their central air conditioning based on previously programmed set points. These two programs achieved 12 percent and 18 percent reductions in peak demand, respectively, with the difference in results explained by the enabling technology, *i.e.*, the programmable thermostat.[158]

- *Colorado*: In March 2008, Xcel Energy launched a $100 million smart grid demonstration project to equip homes in Boulder, Colorado with demand response technologies. Among other things, Xcel Energy plans to test the idea of coupling demand response with the integration of intermittent renewables by sending, for example, signals to meters that would activate household appliances such as dishwashers or heating panels when the wind happens to blow.[159]

- *Maryland*: Baltimore Gas and Electric Company conducted in 2008 a four-month critical peak rebate pilot with 1,000 Maryland customers.[160]

- *California*: In November 2007, the California ISO released a report on the integration of renewables that stated, "pairing electricity-reducing programs . . . with renewable power helps offset the swings in output produced by green resources that are dependent on nature."[161] In conjunction with the report, the California ISO also announced the opening of its new demand response lab - DR365. The demand response laboratory demonstrates "set and forget" automation technology that helps consumers, large and small, make predefined changes to their electricity usage that will reduce the strain on the grid, while reducing the strain on costs.[162]

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[157] Oregon Public Utility Commission, Order No. 08-245 (May 5, 2008).

[158] Faruqui, Ahmad and Wood, Lisa, *Quantifying the Benefits of Dynamic Pricing in the Mass Market*, Edison Electric Institute, January 2008.

[159] Fairley, Peter, *A Power Grid Smartens Up*, Technology Review, March 20, 2008.

[160] Baltimore Gas and Electric Company press release, *Baltimore Gas and Electric Company Conducts Smart Energy Pricing Pilot to Help Customers Shift or Reduce Electric Use during Summer Peak Periods*, http://ir.constellation.com/phoenix.zhtml?c=112182&p=irol-newsBGEArticle&ID=1166382&highlight=.

[161] CAISO, *Integration of Renewable Resources*, Nov. 2007, http://www.caiso.com/1c51/1c51c7946a480.html.

[162] CAISO press release, *eGrid Technologies Help Achieve Environmental Goals*, Dec. 3, 2007, http://search.caiso.com/search?q=cache:n5gBuaSyWPAJ:www.caiso.com/1ca9/1ca98d4d13d10.pdf+DR365&access=p&output=xml_no_dtd&ie=UTF-8&client=caiso_frontend&site=default_collection&proxystylesheet=caiso_frontend&oe=UTF-8.

Chapter V. Regulatory Barriers to Customer Demand Response

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

(F) regulatory barriers to improved customer participation in demand response, peak reduction and critical period pricing programs.[163]

The regulatory barriers discussed in this chapter are based on input received from industry stakeholders,[164] a review of demand response program experience, and a literature review. The discussion in this chapter divides regulatory barriers into three categories:

- barriers previously identified that are currently being addressed,
- barriers previously identified that remain, and
- newly identified barriers.

Barriers Being Addressed

Based on a review of state, regional and national demand response activity, action is being taken to address, among other things: (1) certain financial/pricing disincentives that discourage utilities from implementing demand response programs; (2) the need for accurate measurement and verification of demand response; (3) collaboration among federal and state entities; (4) existing wholesale and retail rules that discourage demand response participation; and (5) barriers to third-parties offering demand response services.

Financial/Pricing Impacts Associated with Offering Demand Response

Utilities generally earn revenue based on the amount of electricity they sell. If consumption decreases during peak periods due to demand response initiatives and is not increased during off-peak hours, utilities could lose revenue. This potential loss of revenue may discourage utilities from supporting demand response initiatives despite the benefits they create.

States, such as Nebraska, Minnesota, New York, and Colorado, are exploring policy changes, while others, such as Idaho and Utah, are implementing new policies to reduce the disincentives that prevent utilities from implementing demand response programs.[165] These include policies that allow utility profits to be decoupled from sales volumes, which remove a powerful disincentive that would otherwise discourage a utility from adopting a demand response program. Four states are currently investigating decoupling, while ten states have approved decoupling for at least one utility.[166] Some states have recently adopted decoupling, such as Idaho, while others

[163] EPAct 2005 section 1252(e)(3)(F).

[164] FERC Technical Conference on Demand Response in Organized Markets, May 21, 2008.

[165] A good summary of these policies is included in Hope Robertson, *Focusing on the Demand Side of the Power Equation: Implications and Opportunities*, Cambridge Energy Research Associates, May 2006, 15-16.

[166] See The National Association of Regulatory Utility Commissioners, *Decoupling for Electric & Gas Utilities: Frequently Asked Questions.* September 2007.

have been using it for years, such as Maryland. Other policies provide utilities a reasonable opportunity to recover the costs of implementing demand response programs. Additionally, some states have recently enacted policies that provide incentives to utilities for implementing high performance demand response programs. For example, the Idaho Commission approved a load management pilot program proposed by Avista Utilities. At least four times a year, Avista will remotely control appliances in order to reduce the participants' energy consumption during peak events. The utility will provide appliance-specific incentives that will apply to participants variably.

The Commission, in its Wholesale Competition Final Rule required the elimination of charges to a utility (or any buyer) in the wholesale market for taking less energy in real-time than what was purchased day-ahead during a period in which the RTO or ISO declares an operating reserve shortage or makes a generic request to reduce load to avoid an operating reserve shortage.[167] Prior to this regulatory reform a buyer may have been deterred from reducing load during an emergency, due to a penalty for deviating from its day-ahead schedule. This reform promotes the stability of the electrical system and encourages comparability between demand and supply resources.

Measurement and Cost-Effectiveness of Reductions

Deficiencies in both the measurement of demand response and the assessment of its cost-effectiveness continue to be a barrier to the development of demand response as a resource. Accurate methods of measuring reductions resulting from demand response programs are important to ensure that demand response resource providers receive appropriate compensation for their participation and to ensure that those participants actually reduce consumption. Regulators and program managers need accurate cost-effectiveness methods to reliably assess the net benefits of demand response programs at the planning, approval and implementation stages.

Central to the issue of measurement is the "customer baseline". In RTO and ISO markets, participants in demand response programs measure their reductions by comparing actual metered load against an estimate of what metered load would have been without the reduction in demand. This estimate is the customer baseline which can be calculated in a variety of ways. Some market participants may be taking advantage of business rules articulating how to calculate the customer baseline in an attempt to produce a favorable estimate. As discussed in Chapter IV, complaints and concerns arose last year in PJM and ISO-NE about alleged activities by market participants to take advantage of business rules in an attempt to produce a favorable baseline estimate or payment.

In order to address the need for consistent customer baseline development and accurate measurement of reductions achieved, the North American Energy Standards Board (NAESB) is currently developing business practice standards relating to the measurement and verification of demand reductions associated with demand response resources at both the wholesale and retail levels.[168] As discussed in Chapter IV, NAESB released for comment draft standards for wholesale demand response measurement on October 3, 2008.

California regulators are addressing the need for better estimates of the impact of demand response on customer demand in resource planning. As discussed in Chapter IV, the California

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[167] Order No. 719

[168] North American Energy Standards Board, http://www.naesb.org/dsm-ee.asp.

Public Utilities Commission has made significant progress in addressing this issue through Rulemaking R07-01-041, which outlines the process for the development of demand response impacts.[169] As part of this proceeding, the California Public Utilities Commission issued Decision 08-04-050, which established ex-ante and ex-post demand response impact protocols.

Work is also underway to update and standardize methods for determining the costs and benefits of demand response programs, *i.e.*, cost-effectiveness. The Pacific Northwest Demand Response Project[170] is discussing best practices. One of the project's goals is to develop a common method for determining the cost-effectiveness of demand response programs and it has a working group devoted to this particular issue.[171] While the California Public Utilities Commission did not address cost-effectiveness methodologies in its demand impact decision, it is currently in the process of developing them.[172]

Better Coordination of Federal-State Policies

There are two ongoing collaborative efforts addressing demand-side issues. The NARUC-FERC Demand Response Collaborative is exploring how state and federal policy makers can better coordinate their respective demand response policies and practices and is in the process of developing a research report on industry barriers. [173] The second partnership is the NARUC-FERC Smart Grid Collaborative, which examines grid modernization and possible ways of enabling customers to make real-time decisions about energy use. These collaborative efforts are discussed in more detail in Chapter IV.

In addition, the Commission, as part of the Energy Independent and Security Act of 2007, is required to conduct a National Assessment of Demand Response and create a National Action Plan on Demand Response. The National Assessment will provide a comprehensive report of demand response potential in five and ten-year horizons and identify obstacles that inhibit higher levels of achievable potential. The National Action Plan will identify requirements for technical assistance to states; requirements for a customer education; and communications program and tools needed by customers, states, utilities and demand response service providers to achieve this potential.

Barriers to Third Parties Providing Demand Response Services

The Commission in its Wholesale Competition Final Rule requires RTOs and ISOs to amend their market rules as necessary to permit an aggregator of retail customers to bid demand response on behalf of its retail customers directly into the organized markets, unless the laws or

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[169] California Public Utilities Commission, Rulemaking 07-01-041 (Order Instituting Rulemaking Regarding Policies and Protocols for Demand Response Load Impact Estimates, Cost-Effectiveness Methodologies, Megawatt Goals and Alignment with California Independent System Operator Market Design Protocols) (January 25, 2007).

[170] The Pacific Northwest Demand Response Project is a collaborative process formed in 2007 to encourage the appropriate development of demand response in the Pacific Northwest. The project is supported by four states in the Pacific Northwest, Bonneville Power Administration, consumer-owned utilities and the Northwest Power and Conservation Council.

[171] Northwest Power and Conservation Council, available at http://www.nwcouncil.org/energy/dr/meetings/2007_05/Default.htm.

[172] California Public Utilities Commission, Ruling in Rulemaking 07-01-041 (Administrative Law Judge's Ruling Setting Comment Period on Staff Cost-Effectiveness Framework and Related Issues) (April 4, 2008).

[173] National Association of Regulatory Utility Commissioners, an association comprised of commissioners from utility regulatory bodies in each state.

regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate.[174] This policy should reduce the barrier to third parties providing demand response services by permitting an aggregator to act as an intermediary for smaller loads that cannot individually participate in an organized market.

Barriers Remaining

Limited Number of Retail Customers on Time-Based Rates

There is a significant opportunity for increased demand response if retail customers were on time-based rates. The costs of operating electric systems vary based on a number of factors, including time-of-day and season; in organized markets, wholesale prices may change significantly from hour to hour, or even in shorter increments of time. However, most customers are on fixed retail rates that do not reflect variations in electricity costs. Instead, rates are based on average costs over a year.[175] Customers that do not see time-based rates do not lower their demand when these prices are high. Such price-responsive demand is considered to be one of the most effective forms of demand response.

Activity to implement time-based rates has been limited. Although large industrial and commercial customers in a few states have direct exposure to hourly pricing and several states have recently implemented default time-based rates for their largest customers, residential customers remain insulated from these time-based rates. Contributing factors are the current low penetration of advanced meters and delays in the utilization of these meters to support time-based rates.

Lack of Sufficient Access to Timely Data and Lack of Coordination and Information Sharing Continues to Impede Market Transparency

The provision of information on electricity usage in real time (instantaneously) or near real time can significantly increase customer demand responsiveness. While advanced metering infrastructure systems capable of measuring and providing detailed electricity usage data exist, the cost of deploying this technology remains an obstacle. Regulatory policies that govern cost recovery of utility investment may contribute to a lack of investment in advanced metering infrastructure in many states, although, as noted in chapter II, some states have developed policies to encourage investment.

Also, even where good data is available to the utility, policies and regulations regarding access to meter data have not evolved at the same pace as meter technology and data retrieval methods, preventing customers from having timely access to their data. Retail tariffs and regulations typically restrict access to customer meter data, making information retrieval for independent aggregators of retail customers time consuming and expensive. Insufficient market transparency also limits the participation of demand response resources in organized markets. Greater market transparency should also enhance grid operation and planning through timely measurement and tracking of customer electricity demand levels and patterns. Last, a lack of sufficient real-time coordination and information sharing is a barrier to the effective use of demand response

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[174] Order No. 719

[175] As discussed in Chapter III, a variety of time-based rate options that fully or partially expose retail customers to wholesale prices are available, but they are not widely offered.

resources. The need for access to meter data and customer information has been recognized in at least one region. PJM has identified the need for standards for access to advanced metering and data management as a key element of their "Demand Response Roadmap."[176] Similar approaches to making such information more readily available for independent aggregators, RTOs and ISOs could encourage participation in demand response programs.

State-Level Barriers

State-level barriers to the introduction of time-based rates remain; however, as noted in chapter IV some states have taken significant steps to address this barrier. Currently in some states, state statutes may limit opportunities for utilities to implement time-based rates for residential customers. To address this barrier, states are examining the affect of time-based rates on electricity consumption patterns through pilot programs.[177] Additional emphasis on removing barriers for residential customers' participation in time-based rate programs could encourage wider adoption of time-based rates.

Cost Recovery and Incentives for Enabling Technologies

Enabling technology, such as advanced metering infrastructure, home area networks and smart thermostats, is necessary in order to fully develop demand response at the residential level. Without enabling technology, utilities are less able to facilitate customer response, measure reductions in consumption resulting from demand response programs, and compensate customers for these reductions. However, the deployment of advanced meters and other enabling technologies requires significant investments and outlays of capital on the part of utilities. Additionally, rate recovery for advanced metering remains a controversial issue. Despite the operational cost savings that can be achieved through use of enabling technologies, existing regulatory uncertainty coupled with the financial burden of investment make deployment a difficult choice for utilities. Chapter II of this report highlights state actions taken over the past year.

Newly Identified Potential Barriers to Demand Response

The last set of potential barriers were raised by participants in the Commission's May 21, 2008 Demand Response Technical Conference. Without confirming that all the issues raised in the technical conference and elsewhere are in fact significant barriers to demand response, we present them here as areas for possible future consideration.

Market Rules and Governance

Market participants raised several concerns about current RTO and ISO market rules and governance at the Commission's May 21, 2008 Demand Response Technical Conference. Several speakers at the technical conference argued that RTO and ISO committee voting rules result in market rules that prevent comparable and fair treatment of demand response resources,

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[176] PJM, *Building the DSR Roadmap: Proceedings of the PJM Symposium on Demand Response II*, October 2008.

[177] See, for example, the results from Public Service Electric & Gas's MyPower pilot. During testing in 2006 and 2007, customers using thermostats that automatically respond to price signals successfully reduced their on-peak period demand by 47 percent on summer peak days. See http://www.demandresponsetownmeeting.com/presentations/ppt/Presentation_Lynk_Fred.ppt.

to the advantage of supply-side resources, arguing that these market rules diminish the impact of demand response on market prices and reduce the role of demand response in market power mitigation. For example, Eric Woychik of Comverge, who spoke at the technical conference, stated that "[t]he primary overarching problem is RTO/ISO governance and committee voting which result in market rules that cut against comparable and fair treatment of [demand response]…."[178] Paul Peterson of Synapse Energy Economics, agreed that voting rules present a challenge, but noted that the degree of the problem varies across RTOs and ISOs. Other speakers at the conference pointed out that RTOs and ISOs have been among the most proactive in integrating demand response into power markets. Further, the Commission has addressed several broad issues regarding RTO and ISO demand response and RTO and ISO responsiveness to their stakeholders in the wholesale competition final rule as well as directing the RTO's and ISO's to identify any regulatory barriers to demand response participation.

One modification to RTO and ISO market rules suggested at the technical conference would be to require that customers receive the difference between the market price and the customer's retail rate.[179] It is argued that this would reduce the differences in treatment of demand and supply resources, and would impact customers directly by providing them with the benefits of their reductions. As stated by David Brewster of EnerNoc, "this is not a subsidy and it's not an incentive… this should be considered as sort of the default starting point for determining the appropriate compensation for demand response resources in wholesale markets."[180] However, the issue of setting such a default price starting point was a contentious one among technical conference participants. Another critical and contentious issue to some participants was a lack of incentive payments for demand response. Some participants believe that the bill reductions that accompany demand reductions need to be supplemented by additional payments for participating in a demand response program. The intent for these incentive payments would be to foster a fully developed market that will eventually no longer need such payments.[181] Others at the technical conference opposed such incentives, and argued that the better solution would be for retail prices to reflect wholesale prices.[182]

The development of consistent compensation rules could foster confidence in the market. Providers as well as customers understand that the price of these demand-side resources will vary, but having confidence in the market will encourage providers to rely on their own forecast and invest appropriately for optimal participation. An example illustrating the key role of confidence to widespread program deployment is the PJM capacity market where customer participation tripled following the implementation of the PJM reliability model in 2007.[183]

The Need for More Variety in Demand Response Programs

The variety of customers that could potentially provide demand response resources is wide. Potential participants include residential customers, commercial customers of varying sizes, and large industrial customers involved in a range of different production activities that use varying amounts of electricity as an input. Each of these potential demand response providers have different needs and require varying specifications in a demand response program. Furthermore,

[178] Tr. 15:14-16 (Eric Woychik).
[179] Tr. 31:23-25 (David Brewster).
[180] Tr. 32:1-5 (David Brewster).
[181] Tr. 33:8-12 (David Brewster).
[182] See, for example, Tr. 80:3-6 (David LaPlante) and Tr. 98:10-19 (Robert Borlick).
[183] Tr. 24:9-16 (James Eber).

these providers have different limitations to and costs resulting from their participation. The development of a greater variety of demand response programs that incorporate the flexibility necessary to promote such participation without compromising the reliability of demand response resources will greatly facilitate the participation of more customers in demand response initiatives.

Recommendations

In the 2006 FERC Demand Response Report, Commission staff recommended to the Commission several items related to demand response. Staff recommended that the Commission coordinate wholesale and retail demand response programs with state electricity regulators, utilities, and other interested parties; explore how to better accommodate demand response in wholesale markets; and consider approaches to eliminating any regulatory barriers to improved participation in demand response, peak reduction and critical peak pricing programs. As discussed in Chapter IV above, the Commission took several actions along the lines of staff's recommendations. The Commission helped form the NARUC-FERC Demand Response Collaborative in November 2006 to coordinate wholesale and retail demand response programs. In its rule on Competition in Regions with Organized Electric Markets, Order No. 719, issued in October 2008, the Commission required several modifications to the design of organized wholesale electricity markets to address barriers to comparable treatment of demand response resources and to identify additional barriers to such treatment of demand response resources.

Staff recommends that the Commission continue to make demand response a priority. Specific recommendations include: (1) continue current coordination with NARUC on finding demand response solutions, with a focus on aligning retail demand response programs and time-based rates with wholesale market designs; (2) continue exploring how to remove barriers to the comparable treatment of demand response resources in wholesale markets; (3) coordinate the Commission's National Assessment of Demand Response and National Action Plan for Demand Response efforts required by Congress in the Energy Independence and Security Act of 2007 with the ongoing annual demand response reporting required by the Energy Policy Act of 2005 to ensure effective use of Commission resources; (4) support the efforts of organizations such as NERC, NAESB, and EIA to develop practical means to measure, verify, forecast, and track demand response; and (5) explore possible linkages among demand response, energy efficiency, and smart grid programs. As required by law, in 2009 the Commission's National Assessment of Demand Response will contain additional recommendations for achieving the nation's demand response potential.

Appendix A: EPAct 2005 Language on Demand Response and Smart Metering

SEC. 1252. SMART METERING.

(a) IN GENERAL.—Section 111(d) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2621(d)) is amended by adding at the end the following:

''(14) TIME-BASED METERING AND COMMUNICATIONS.—
(A) Not later than 18 months after the date of enactment of this paragraph, each electric utility shall offer each of its customer H. R. 6—371 classes, and provide individual customers upon customer request, a time-based rate schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility's costs of generating and purchasing electricity at the wholesale level. The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology.
''(B) The types of time-based rate schedules that may be offered under the schedule referred to in subparagraph (A) include, among others—

> ''(i) time-of-use pricing whereby electricity prices are set for a specific time period on an advance or forward basis, typically not changing more often than twice a year, based on the utility's cost of generating and/or purchasing such electricity at the wholesale level for the benefit of the consumer. Prices paid for energy consumed during these periods shall be pre-established and known to consumers in advance of such consumption, allowing them to vary their demand and usage in response to such prices and manage their energy costs by shifting usage to a lower cost period or reducing their consumption overall;
> ''(ii) critical peak pricing whereby time-of-use prices are in effect except for certain peak days, when prices may reflect the costs of generating and/or purchasing electricity at the wholesale level and when consumers may receive additional discounts for reducing peak period energy consumption;
> ''(iii) real-time pricing whereby electricity prices are set for a specific time period on an advanced or forward basis, reflecting the utility's cost of generating and/or purchasing electricity at the wholesale level, and may change as often as hourly; and
> ''(iv) credits for consumers with large loads who enter into pre-established peak load reduction agreements that reduce a utility's planned capacity obligations.

''(C) Each electric utility subject to subparagraph (A) shall provide each customer requesting a time-based rate with a time-based meter capable of enabling the utility and customer to offer and receive such rate, respectively.
''(D) For purposes of implementing this paragraph, any reference contained in this section to the date of enactment of the Public Utility Regulatory Policies Act of 1978 shall be deemed to be a reference to the date of enactment of this paragraph.
''(E) In a State that permits third-party marketers to sell electric energy to retail electric consumers, such consumers shall be entitled to receive the same time-based metering and communications device and service as a retail electric consumer of the electric utility.
''(F) Notwithstanding subsections (b) and (c) of section 112, each State regulatory authority shall, not later than 18 months after the date of enactment of this paragraph conduct an investigation in accordance with section 115(i) and issue a decision whether it is appropriate to implement the standards set out in subparagraphs (A) and (C).''. H. R. 6—372

(b) STATE INVESTIGATION OF DEMAND RESPONSE AND TIMEBASED METERING.—Section 115 of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2625) is amended as follows:
(1) By inserting in subsection (b) after the phrase ‘‘the standard for time-of-day rates established by section 111(d)(3)’’ the following: ‘‘and the standard for time-based metering and communications established by section 111(d)(14)’’.
(2) By inserting in subsection (b) after the phrase ‘‘are likely to exceed the metering’’ the following: ‘‘and communications’’.
(3) By adding at the end the following:
‘‘(i) TIME-BASED METERING AND COMMUNICATIONS.—In making a determination with respect to the standard established by section 111(d)(14), the investigation requirement of section 111(d)(14)(F) shall be as follows: Each State regulatory authority shall conduct an investigation and issue a decision whether or not it is appropriate for electric utilities to provide and install time-based meters and communications devices for each of their customers which enable such customers to participate in time-based pricing rate schedules and other demand response programs.’’.
(c) FEDERAL ASSISTANCE ON DEMAND RESPONSE.—Section 132(a) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2642(a)) is amended by striking ‘‘and’’ at the end of paragraph (3), striking the period at the end of paragraph (4) and inserting ‘‘; and’’, and by adding the following at the end thereof: ‘‘(5) technologies, techniques, and rate-making methods related to advanced metering and communications and the use of these technologies, techniques and methods in demand response programs.’’.
(d) FEDERAL GUIDANCE.—Section 132 of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2642) is amended by adding the following at the end thereof:
‘‘(d) DEMAND RESPONSE.—The Secretary shall be responsible for—
‘‘(1) educating consumers on the availability, advantages, and benefits of advanced metering and communications technologies, including the funding of demonstration or pilot projects;
‘‘(2) working with States, utilities, other energy providers and advanced metering and communications experts to identify and address barriers to the adoption of demand response programs; and
‘‘(3) not later than 180 days after the date of enactment of the Energy Policy Act of 2005, providing Congress with a report that identifies and quantifies the national benefits of demand response and makes a recommendation on achieving specific levels of such benefits by January 1, 2007.’’.
(e) DEMAND RESPONSE AND REGIONAL COORDINATION.—
(1) IN GENERAL.—It is the policy of the United States to encourage States to coordinate, on a regional basis, State energy policies to provide reliable and affordable demand response services to the public.

(2) TECHNICAL ASSISTANCE.—The Secretary shall provide technical assistance to States and regional organizations formed by two or more States to assist them in—

(A) identifying the areas with the greatest demand response potential; H. R. 6—373
(B) identifying and resolving problems in transmission and distribution networks, including through the use of demand response;
(C) developing plans and programs to use demand response to respond to peak demand or emergency needs; and
(D) identifying specific measures consumers can take to participate in these demand response programs.

(3) REPORT.—Not later than 1 year after the date of enactment of the Energy Policy Act of 2005, the Commission shall prepare and publish an annual report, by appropriate region, that assesses demand

response resources, including those available from all consumer classes, and which identifies and reviews—

(A) saturation and penetration rate 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 improve customer participation in demand response, peak reduction and critical period pricing programs.

(f) FEDERAL ENCOURAGEMENT OF DEMAND RESPONSE DEVICES.—It is the policy of the United States that time-based pricing and other forms of demand response, whereby electricity customers are provided with electricity price signals and the ability to benefit by responding to them, shall be encouraged, the deployment of such technology and devices that enable electricity customers to participate in such pricing and demand response systems shall be facilitated, and unnecessary barriers to demand response
participation in energy, capacity and ancillary service markets shall be eliminated. It is further the policy of the United States that the benefits of such demand response that accrue to those not deploying such technology and devices, but who are part of the same regional electricity entity, shall be recognized.

(g) TIME LIMITATIONS.—Section 112(b) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2622(b)) is amended by adding at the end the following:

''(4)(A) Not later than 1 year after the enactment of this paragraph, each State regulatory authority (with respect to teach electric utility for which it has ratemaking authority) and each nonregulated electric utility shall commence the consideration referred to in section 111, or set a hearing date for such consideration, with respect to the standard established by paragraph (14) of section 111(d).

''(B) Not later than 2 years after the date of the enactment of this paragraph, each State regulatory authority (with respect to each electric utility for which it has ratemaking authority), and each nonregulated electric utility, shall complete the consideration, and shall make the determination, referred to in section 111 with respect to the standard established by paragraph (14) of section 111(d).''.

Appendix B: Acronyms Used in the Report

AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading OR Automatic Meter Reading
ANSI	American National Standards Institute
ASCC	Alaska Systems Coordinating Council
CAISO	California Independent System Operator
EIA	Energy Information Administration
EISA 2007	Energy Independence and Security Act of 2007
EPAct 2005	Energy Policy Act of 2005
ERCOT	Electric Reliability Council of Texas, Inc.
FERC	Federal Energy Regulatory Commission (
FRCC	Florida Reliability Coordinating Council
G&T	Generation and Transmission
HEFPA	Home Energy Fair Practices Act
kW	Kilowatt
kWh	Kilowatt-hour
ISO	Independent system operator
ISO-NE	Independent System Operator of New England
LaaR	Load acting as a resource (ERCOT category)
MADRI	Mid-Atlantic Distributed Resources Initiative
MISO	Midwest Independent System Operator
MRO	Midwest Reliability Organization
MRTU	Market redesign and technology update
MWDRI	Midwest Demand Response Initiative
MW	Megawatt
MWh	Megawatt-hour
NAESB	North American Energy Standards Board
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NYISO	New York Independent System Operator
OATT	Open Access Transmission Tariff
PJM	PJM Interconnection, L.L.C
RFC	Reliability*First* Corporation
RPM	Reliability Pricing Model
RTO	Regional transmission organization
SERC	SERC Reliability Corporation
SPP	Southwest Power Pool, Inc.
SPPR	Southwest Power Pool Regional Entity delete the spurious “e”
TRE	Texas Regional Entity
WECC	Western Electricity Coordinating Council

Appendix C: Glossary for the Report

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

Actual Peak Reduction: The coincident reductions to the annual peak load (measured in megawatts) achieved by customers that participate in a demand response program at the time of the annual system peak of the utility or RTO/ISO. It reflects the changes in the demand for electricity resulting from a sponsored demand response program that were in effect at the same time a utility or RTO/ISO experienced its annual system peak load. For curtailment service providers (CSPs), the actual peak reduction should include the demand response load provided at the time of the peak for the region or the utility service territory in which they aggregate customer load. For utilities, it should include the demand response load at the time of the utility annual system peak load. For RTOs and ISOs, it should include the demand response load at the time of the RTO/ISO annual system peak load.

Advanced Metering or Advanced Metering Infrastructure (AMI): A system including measurement devices and a communication network, public and/or private, that records customer consumption, and possibly other parameters, hourly or more frequently and that provides for daily or more frequent transmittal of measurements to a central collection point.

Ancillary Services: Services that ensure reliability and support the transmission of electricity to customer loads. Such services may include: energy imbalance, spinning reserves, supplemental reserves, reactive supply and voltage control, and regulation and frequency response.

Ancillary Service Market Programs: Demand response programs in which customers bid load reductions in RTO/ISO ancillary services markets. If their bids are accepted, they are paid the market price for committing to be on standby. If their load reductions are needed, they are called by the RTO/ISO, and may be paid the spot market energy price.

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

Automated Meter Reading (AMR): Automatic or automated meter reading -- allows meter reads to be collected without actually viewing or touching the meter with any other equipment. Since AMR meters generally lack the two-way communicating capabilities of AMI meters, AMR meters cannot meet Commission staff's definition of advanced metering. In contrast with AMI and its fixed communications networks, AMR meters are read by drive-by or walk-by remote readers.

Automated Demand Response: Programs in which end users' electrical systems or appliances respond directly to price or emergency signals without the need for human intervention.

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

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

Billing or Revenue Purposes: The determination of charges and bills to be assessed for products and/or services used.

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

Critical Peak Pricing: CPP rates typically charge a much higher price during a few hours per day on critical peak days. The number of critical peak days is usually capped for a calendar year and are linked to conditions such as system reliability concerns or very high supply prices.

Critical Peak Rebate: CPR rates allow customers to earn a rebate by reducing energy use from a baseline during a few hours on critical peak days. Like CPP, the number of critical peak days is usually capped for a calendar year and are linked to conditions such as system reliability concerns or very high supply prices.

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

Customer Baseline: The level of electricity consumption that a customer would have consumed if the demand response program participant had not curtailed consumption. This level can be estimated through several methods, such as an average of customer electricity demand over several similar days.

Decoupling: Policies that separate changes in utility revenue with changes in sale volume to remove disincentives for utilities to promote policies or programs that reduce electric consumption.

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

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

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

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

Demand Response Program: A company's service/product/tariff related to 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.

Direct Load Control: A demand response activity by which the program sponsor remotely shuts down or cycles a customer's electrical equipment (e.g. air conditioner, water heater) on short notice.

Direct load control programs are primarily offered to residential or small commercial customers.

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

Economic Demand Response Event: A demand response event during which a customer decreases the amount of power being used or a demand response program sponsor directs decrease in the amount of power being used because of an economic market opportunity or dispatch instructions.

Emergency Demand Response Event: A demand response event called by the program sponsor in response to an emergency declared by the demand response sponsor or by another entity such as a utility or RTO/ISO.

Emergency Demand Response Program: A demand response program that provides incentive payments to customers for load reductions achieved during an emergency demand response event.

Energy Efficiency: Refers to programs that are aimed at reducing the energy used by specific end-use devices and systems, typically without affecting the services provided. These programs reduce overall electricity consumption (reported in megawatt-hours), often, but not always, without explicit consideration for the timing of program-induced savings. Such savings are generally achieved by substituting technologically more advanced equipment to produce the same level of end-use services (e.g. lighting, heating, motor drive) with less electricity. Examples include energy saving appliances and lighting programs, high-efficiency heating, ventilating and air conditioning (HVAC) systems or control modifications, efficient building design, advanced electric motor drives, and heat recovery systems.

Enhanced Customer Service: The ability to offer customers: billing flexibility; additional rate options; better outage management; timely information on energy usage; fewer bill estimates; and flexibility in starting/ending service.

Entity: The organization that is (1) responding to the survey, (2) offering demand response programs, time-based rates/tariffs or (3) using advanced or smart meters.

Home Area Network (HAN): A HAN is a communication network of devices in and around a customer premise offering customers the ability to better manage their energy use and their electric bill.

Hourly Pricing: A pricing plan where prices for energy vary by the hour usually based in part on a wholesale price for electricity.

ICAP Credit: An RTO/ISO installed capacity (ICAP) credit that can be used to satisfy a resource requirement.

Interoperability: The ability of two or more systems or components to exchange information and to use the information that has been exchanged.

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

Incentive-Based Demand Response Programs: Provide motivation or direct payments to customers to induce load reductions when needed, usually for system reliability.

Interface with Water or Gas Meters: The ability of the AMI network to collect water or gas meter readings and to transmit those readings over the AMI network to a central collection point.

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

Interval: The period of time for which advanced or smart meters measure energy usage and possibly other measurements, usually in increments of minutes, such as five minute intervals, 15 minute intervals, and/or hourly intervals.

Interval Usage: The amount of energy measured by advanced meters for the specified interval. Examples are the energy measured in kWh for five minutes, 30 minutes, or an hour.

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

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

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

Mandatory: Participation in the demand response program is required based on the customer's size or rate class. Customers are not offered the option to take service under a different pricing plan or tariff.

Market Penetration: The ratio of advanced meters to all installed meters.

Maximum Demand of Enrolled Customers: The highest level of total demand in MWs for customers enrolled and participating in a demand response program. This may be reported as tracked, such as hourly demand, 30 minute demand, 15 minute demand, or 5 minute demand.

Maximum Demand: The highest level of demand in MWs as tracked, such as an hourly demand, 30 minute demand, 15 minute demand or 5 minute demand.

Maximum Duration of Event: A specified maximum length of time a particular demand response event will continue, usually defined by 30 minute or hourly increments.

Minimum Payment Rate: The smallest amount of money a program sponsor will provide a demand response program participant for reduced energy consumption and/or load.

Minimum Reduction: A threshold established by the demand response program sponsor as the minimum demand reduction a participant must achieve during a demand response event to be considered as participating in that event or to qualify for the demand response program.

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

Other Programs/Tariff: A company or utility's service/product/compilation of all effective rate schedules, general terms and conditions and standard forms related to demand response/AMI services for customers which are not residential, commercial, commercial, industrial or transportation.

Outage Detection: The ability of an advanced or smart metering system to determine the absence of electric energy to a customer meter.

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

Outage Mapping: The ability of an advanced or smart metering system to provide information as to the extent and location of an outage within a distribution grid.

Outage Restoration: The ability of an advanced or smart metering system to verify power is supplied to a meter.

Peak MW demand for 2007: The largest demand (MW) on the power system during 2007.

Penalties: Reduced payments or fines which result when a demand response program participant fails to meet target reductions in power demand or elects to not reduce consumption during a demand response event.

Potential MWh Change: The potential total annual change in energy consumption (measured in MWh) that would result from the deployment of demand response programs. It reflects the total change in consumption if the full demand reduction capability of the program was deployed, as opposed to the actual MWh change during the year without the program in place.

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

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

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

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

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

Price-Based Rate/Tariff: The terms and conditions under which customers can choose their energy consumption pattern based on the price they would pay for power during a specific period of time. Examples include time-of-use, real-time pricing, hourly pricing, critical peak pricing and critical peak rebates.

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

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

Programmable Communicating or "Smart" Thermostats: A programmable thermostat is a thermostat which is designed to adjust the temperature according to a series of programmed settings that take effect at different times of the day. Programmable communicating thermostats or "smart" thermostats can receive information wirelessly.

Provide the Information to the Entity at Least Daily: The information measured by the advanced or smart metering system will be communicated to the entity providing energy and/or delivery services via the communication network at least once per day and possibly more frequently (such as four times per day or hourly.)

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

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

Publicly Owned Electric Utility: A class of ownership found in the electric power industry. This group includes those utilities operated by municipalities, political subdivisions, and state and federal power agencies (such as the Bonneville Power Administration and the Tennessee Valley Authority).

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

Reduce Line Loses: The ability to use the AMI network to lower line losses on a transmission or distribution system.

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

Remotely Change Metering Parameters: The ability to change any parameter that affects the operation or communications of an advanced or smart meter via the communication network as opposed to visiting the location of the metering device.

Remotely Upgrade Firmware in Endpoint: The ability to remotely change the operating functionality of metering endpoints.

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

Retail Customers: A purchaser of energy who consumes the energy product.

Revenue Assurance: A set of activities designed to accurately match revenue from providing electric service to customers with customers' use of energy.

Revenue/Billing Meters: A device that charges an entity for the energy products and/or services used.

Smart Grid System: A system which includes a variety of operational and energy measures-including smart meters, smart appliances, renewable energy resources, and energy efficiency resources.

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

System Peak MW Demand: Largest possible size of load (MW) on a power system during 2007.

Theft Detection: The ability to detect potential tampering, bypassing or unauthorized removal of revenue or billing meters that should be investigated by the utility.

Time-Based Rates: A retail rate or tariff in which customers are charged different prices for different times during the day. Examples are time-of-use rates, real time pricing, hourly pricing, and critical peak pricing. These rates do not include seasonal rates and inverted block or declining block rates.

Time-of-Use Rate: A rate where usage unit prices vary by more than one time period within a 24-hour day. Time-of-use rates reflect the average cost of generating and delivering power during those time periods. Daily pricing blocks might include an on-peak, partial-peak, and off-peak price for non-holiday weekdays, with the on-peak price as the highest price, and the off-peak price as the lowest price.

Transformer Sizing: Analysis of the ideal rating for a transformer on a distribution/transmission grid to minimize line losses and provide sufficient capacity to handle peak loads now and in the future.

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

Transportation Programs/Tariffs: A company or utility's service/product/compilation of all effective rate schedules, general terms and conditions and standard forms related to demand response/AMI services for transportation customers.

Voluntary: Where customers have the option to participate or not to participate. This would include opt-out programs where customers are automatically enrolled but are allowed to discontinue their participation.

Appendix D: The 2008 FERC Survey

Summary

The Energy Policy Act of 2005 (EPAct 2005) requires that the Federal Energy Regulatory Commission prepare and publish an annual report, by appropriate region, that assesses electricity demand response resources, including those available from all consumer classes. Commission staff determined that a survey of a full set of private and public entities that provide electric power and demand response to customers would help fulfill the requirement.

Between January 2008 and June 2008, Commission staff – with the technical support of UtiliPoint International, Inc. (UtiliPoint):

- Identified survey respondents ("the respondent universe");
- Developed a voluntary survey and sampling design based on the 2006 FERC Demand Response and Advanced Metering Survey (2006 FERC Survey);
- Implemented the survey design in an Internet-based survey software platform;
- Fielded the 2008 FERC Survey, collected the data, and followed-up with respondents where necessary; and
- Conducted data analysis of the survey responses.

Responses to the survey were requested from 3,407 entities from all 50 states representing all aspects of the electricity delivery industry: investor-owned utilities, municipal utilities, rural electric cooperatives, power marketers, state and federal agencies, and demand response providers. The respondent universe was based on the universe of respondents identified by the Energy Information Administration (EIA) for their EIA-861 Form. The respondent universe added two additional categories of respondents to the base set of EIA contacts – Regional Transmission Organizations (RTOs)/Independent System Operators (ISOs) and curtailment service providers.

More than 2,094 entities responded to at least one of the two major sections (demand response or the advanced metering) of the 2008 FERC Survey (a response rate of over 61 percent), an increase from the 2006 FERC Survey response rate of 55 percent. Since some respondents only responded to only one of the survey sections, response rates for the individual sections are lower. More respondents completed the advanced metering section of the survey (60 percent) than the demand response section (55 percent).

The following provides a detailed review of the steps Commission staff took to implement the 2008 FERC Survey.

Development of the FERC Survey and Sampling Design

The 2008 FERC Survey was conducted subject to the same Office of Management and Budget (OMB) authorization that was provided to the Commission in 2006. The 2006 authorization was extended to April 30, 2008. As was done in 2006, Commission staff fielded the survey on a voluntary rather than a mandatory basis. Commission staff designed the draft survey to collect the needed information in three sections:

- General and identifying information on the respondents (this section also allowed the respondent to identify whether it operated demand response programs and advanced metering);
- Information on incentive-based demand response and time-based rates (Form FERC-727); and
- Information on advanced metering infrastructure (Form FERC-728).

Dividing the 2008 FERC Survey into three sections allowed different people within an organization to collect data and complete the forms at the same time. The general information section of the 2008 FERC Survey helped link data from all parts of the 2008 FERC Survey together for each respondent. It also provided a fast way for organizations to respond to the 2008 FERC Survey if they had no information to report.

Commission staff conducted the FERC Survey using the Internet. All three sections of the 2008 FERC Survey were posted on the Commission's web page and the links allowed those who took the FERC Survey to submit their electronic responses directly to FERC and UtiliPoint.[1] In addition, links to the on-line survey were sent to survey respondents by email and in letters.

The content of the 2008 FERC Survey mirrored the content the 2006 FERC Survey collected. Minor revisions were made to the wording of the questions to improve clarity, ask questions more efficiently, and reduce the length of the survey. In addition, changes included a greater use of tables, the incorporation of pop-up help windows for key terms, and instructions aimed to improve the survey's user-friendliness.

The Respondent Universe

To analyze the survey data and calculate statistics for this report, Commission staff reviewed the composition of the respondent universe, and found that there were 3,407 organizations as listed in Table D-1.

The region definition used in the FERC Survey was based on that used by the North American Electric Reliability Corporation (NERC). Using NERC regions allows collection of data based on how energy is traded and managed. It provides the most useful regional grouping for the consideration of demand response resources and advanced metering deployment that would potentially reduce barriers for participation in demand response and time-based rate programs and/or tariffs.

[1] Links to the 2008 FERC Survey documents can be found at http://www.ferc.gov/industries/electric/indus-act/demand-response/2008/survey.asp.

Table D-1. Respondent Universe of the 2008 FERC Survey

Group Name	Number of Organizations in Group
Municipal	1,845
Cooperative	884
Investor Owned	223
Power Marketer	162
Public Utility District	126
Municipal Authority	21
Retail[2]	107
State	21
Federal	10
Independent System Operator	8
Grand Total	3,407

Source: EIA, Internet

FERC Survey Methodology

In 2006, Commission staff worked with OMB staff to develop a survey and sampling approach that would ensure that potential self-selection bias could be identified and analyzed. Commission staff and UtiliPoint followed the same sampling and stratification approach in the 2008 FERC Survey. Under this approach, Commission staff and Utilipoint :

- Developed the pool of utility respondents from the 2007 EIA respondent list and other industry-related publications. The number of organizations in each group was verified;
- Segmented the pool of 2008 FERC Survey respondents by NERC region, type of utility and the number of retail customers served;
- Sized respondents based on total number of customers each utility reported in its 2006 EIA-861 form, and through communication with the RTOs, ISOs and curtailment service providers as follows:
    - Large (number of customers over 100,000),
    - Medium (number of customers > 25,000 and less than 100,000),
    - Other (0 retail customers or Generation and Transmission utility), and
    - Small (less than or equal to 25,000 customers); and
- Drew a random sample of 732.

Based on the experience with the 2006 FERC Survey, Commission staff expected that the demand response program offerings as well as the penetration of AMI would be substantially different across the different size utilities and across the different types of utilities. In addition, Commission staff anticipated AMI responses from utilities that have ownership or responsibility for revenue and billing metering, such as cooperative, federal, investor-owned, municipal, political subdivision, and state utilities who serve retail customers. Utilities that do not serve retail customers – namely Municipal Marketing Authorities, Wholesalers or Generation and Transmission (G&T) utilities – were not expected to submit responses for the AMI section of the FERC Survey since these types of utilities typically do not own or have responsibility for billing and revenue meters for retail customers. In addition, Power Marketers (which include Competitive Retailers, Energy Service Providers, Retail Providers, and the other names generally used in regions with retail competition or retail choice) were

[2] Retail entities sell electric energy to retail customers where the sale of electricity is open to retail competition.

not expected to submit responses to the AMI section of the FERC Survey because these utilities typically do not own or have responsibility for retail metering.

Fielding the FERC Survey and Analyzing the Data

Efforts to Maximize Response Rates

Similar to efforts undertaken in 2006, Commission staff tried to maximize response rates by using an aggressive outreach approach of alerting large gatherings of organizations that were expected to respond to the FERC Survey of the survey's release and survey response due dates. For example, Commission staff announced preliminary survey plans and discussed these with several trade and state associations including members and/or representatives of the National Association of Regulatory Commissioners, American Public Power Association, Edison Electric Institute, and the National Rural Electric Cooperative Association. In a cooperative spirit and in consideration of the authority that state utility commissioners have in this matter, Commission staff sent letters to state regulators over FERC Chairman Kelliher's signature informing them of the organizations in their state that were asked to participate in the FERC Survey. The letter committed to giving them a status report of whether or not those utilities in their jurisdiction had responded to the FERC Survey in a follow-up letter. Commission staff sent these follow-up letters to the state regulators 30 days after the FERC Survey issued.

Another effort to maximize response and encourage participation in the FERC Survey was customizing the letter Commission staff sent to the respondent universe. The letters used personalized greetings, included references to the potential respondent company by name, provided information about the 2008 FERC Survey, and gave general guidance on how to complete the 2008 FERC Survey. Commission staff sent the 2008 FERC Survey letter via email as well as in hard copy. Delivery of a hard copy of the 2008 FERC Survey package at the place of business was prudent because Commission staff anticipated the email addresses of contacts listed in the 2007 EIA-861 database might have changed since the EIA-861 data was collected.

Commission staff also made several changes to the design of the on-line survey used for the 2006 FERC Survey in an effort to maximize response rates. These changes included the increased use of data entry tables to improve the readability and ease of data input by respondents; adding questions and routing of questions within the general information section to allow respondents who did not have AMI or demand response programs to quickly complete the survey; adding pop-up help windows that contained definitions of key terms; and adding the capability to save the survey by the respondent prior to submittal. The set of survey questions aimed to collect with regards to AMI and demand response programs remained the same as was approved by OMB in 2006. These minor clarifications improved user-friendliness with resulting clarity and shortening of the survey length.

To accommodate respondents who were not comfortable completing a web survey or who did not have access to the Internet, the instructions provided a person's name and contact information so they could find an alternative means for reporting their information. Respondents needing such accommodation received a package by U.S. mail which included a custom letter as well as paper copies of the instructions, frequently asked questions, glossary and survey instruments. The letter included instructions for completing and submitting the FERC Survey manually. As was the case in 2006, respondents were also able to have someone fill out the FERC Survey for them during a phone call, if they so chose. To encourage participation, there was a phone number at the bottom of each page of the electronic and paper versions of the FERC Survey for respondents to call if they encountered problems while filling out the survey. This boosted response rates by solving technical difficulties and providing a way for respondents to get clarifications on questions. For example, some respondents notified Commission staff and UtiliPoint that they were not able to access the information on the web site. Investigation of the matter found that these respondents had pop-up ad blockers on their computers. By disabling this feature on their computer, they were able to complete the survey. Commission staff and UtiliPoint collected and compiled this sort of information into an updated frequently asked question list which was then posted on the survey web page.

To increase the likelihood of getting survey responses from contacts listed in the EIA-861 database that were responsible for reporting on three or more organizations, Commission staff sent customized letters to these contacts. The letter included a spreadsheet they could use to report their data and eliminated the need to fill out the multi-page survey repeatedly.

Commission staff and UtiliPoint followed through by phone calls with those who had not completed the FERC Survey by the deadline. Staff who did the follow-up had experience in interviewing energy market participants had a deep knowledge of advanced metering, demand response, and time-based rates.

UtiliPoint tracked responses as they came in to assess which NERC regions might have been showing under-representation and targeted these for early follow-up.

Survey Response Rates

The overall response rate of 61 percent for the 2008 FERC Survey is high for a voluntary survey, and is higher than the already high response rate achieved in the 2006 FERC Survey. This section discusses survey response in detail and compares the actual response rate with expectations.

Examination of the actual response rates for the two sections of the 2008 FERC Survey in Table D-2 indicates a difference between overall response rates to the demand response and AMI sections of the survey. More respondents completed the advanced metering section of the survey (60 percent) than the demand response section (55 percent). This pattern is consistent for many of the entity type and size groups within the respondent universe. Nevertheless, response rates did not show major differences between the two sections from several key groups. For example, for large investor-owned utilities the response rate for the AMI section of the survey is 99 percent, while the response rate for the demand response section is 97 percent.

The percentage of actual responses by utility size is consistent with UtiliPoint survey experience that large utilities are typically very responsive and medium-sized utilities less so. Experience also shows that small utilities are very responsive when they are directly contacted by phone. However, due to the large number of small utilities that did not respond, a comprehensive respondent follow-up was not economically feasible.

As was achieved in 2006, small cooperative and municipally owned utilities had a very significant – and rare – response rate of greater than 50 percent. Small municipals usually have a voluntary survey response rate of five percent.

In spite of follow up phone calls and in-person conversations with staff and leaders at all levels of the group of retail entities (e.g., curtailment service providers), Commission staff was only able to achieve a response rate for retailers that was 20 percent for the demand response section and 22 percent for the

AMI section. The low participation rate of this section of the respondent universe was consistent with the 2006 Survey experience.

Table D-2. 2008 FERC Survey Responses

Type of Entity	Size	Total Number	DR Sample Response Rate	DR Actual Response Rate	AMI Sample Response Rate	AMI Actual Response Rate
Cooperative	Large	20	70%	70%	75%	75%
	Medium	187	64%	62%	61%	61%
	Small	618	65%	64%	67%	67%
	Other	59	78%	59%	100%	75%
Federal	Medium	1	100%	100%	100%	100%
	Small	6	17%	17%	33%	33%
	Other	3	67%	67%	100%	100%
Investor-Owned	Large	110	97%	97%	99%	99%
	Medium	22	100%	91%	100%	95%
	Small	53	50%	58%	63%	60%
	Other	38	60%	53%	80%	68%
ISO	Other	8	88%	88%	63%	63%
Municipal	Large	19	68%	68%	63%	63%
	Medium	85	56%	48%	58%	53%
	Small	1738	45%	51%	52%	55%
	Other	3	200%	67%	200%	67%
Municipal Authority	Other	21	250%	67%	200%	67%
PUD	Large	7	71%	71%	71%	71%
	Medium	11	83%	64%	83%	64%
	Small	83	50%	61%	75%	70%
	Other	25	100%	60%	100%	64%
Power Marketer	Large	15	27%	60%	60%	60%
	Medium	12	33%	50%	67%	58%
	Small	75	0%	47%	57%	48%
	Other	60	100%	42%	71%	68%
Retail	Other	107	25%	20%	29%	22%
State	Large	2	50%	50%	50%	50%
	Medium	1	0%	0%	100%	100%
	Small	6	100%	100%	100%	100%
	Other	12	50%	50%	83%	83%
Total		**3407**	**63%**	**55%**	**67%**	**60%**

Commission staff and UtiliPoint compared the response rates of the 732 organizations in the random AMI sample to the response rates of the 2,094 in the respondent universe who completed either the demand response program or the AMI sections of the FERC Survey to ascertain whether self-selection bias was present. As can be seen from Table D-2, response rates for the 2008 FERC Survey – overall and by strata – show no statistically significant evidence of self-selection bias. While not identical, response rates from the random sample versus the entire respondent universe do not display major differences.

Working with the Data

As discussed in Chapters II and III, Commission staff used the 2008 FERC Survey to estimate AMI penetration rate and potential peak load reduction. The following discussion describes the analysis undertaken by Commission staff and UtiliPoint.

Advanced Metering

Commission staff developed estimates of the penetration rate of national and regional advanced metering required by Congress through extrapolation of the survey results to produce state, regional, and national estimates. Extrapolation should not produce significant biases because the total number of meters (of all types) reported by the entities that responded to the 2008 FERC Survey account for 91 percent of all currently installed electricity meters in the U.S. The extrapolation process was conducted through the development of regional and entity size weights and is described below.

The information provided by the respondents to the AMI portion of the FERC Survey was weighted to extend the results to all the meters in the U.S. Since almost all of the larger utilities responded to the survey, one can assume that medium and small utilities make up the majority of the nine percent not represented. To ensure that the estimates properly account for the nine percent not included in the responses, the data was weighted. Each entity that was given the opportunity to respond was assigned to a cell defined by the NERC region, type of entity, and size (in terms of the number of meters). The weight was determined by calculating the sum of all meters[3] associated with all of the entities assigned to a particular cell divided by the sum of the total number of meters reported by the respondents in the 2008 FERC Survey.

For example, if 45 percent of small cooperatives were to respond to the survey in the ERCOT region and 100 percent of the large investor-owned utilities responded, the weight for the small cooperatives would be the total meters for all of the small ERCOT cooperatives divided by the total number of meters reported by the 45 percent of coops in ERCOT that responded to the 2008 FERC Survey. This weight would be greater than one. In contrast, the weight for the large investor-owned utilities in ERCOT would be one because all of the large investor-owned utilities responded.

The weight was then used to extrapolate the number of advanced meters in each region, entity type, and size cell from the survey responses. Regional and state estimates were calculated based on these weights.

Demand Response

Since the response rate for the demand response section of the 2008 FERC Survey was not 100 percent, Commission staff developed estimates of total resource contribution in the United States by supplementing the 2008 FERC Survey responses with information on peak load reduction potential from other sources (*e.g.*, 2006 EIA Form 861, RTO or ISO demand response program evaluations, and

[3] Meter counts for entities were taken from customer data reported in the 2007 EIA Form 861. Since Commission staff analysis of customer and meter totals in the 2006 FERC Survey indicates that the total number of meters in the United States is 98 percent of the total number of customers, customer counts can be used as proxy for meters, particularly with entities with fewer customers and meters.

direct contact with non-respondents). Commission staff developed peak load reduction estimates for entities who did not respond to the 2008 FERC Survey from these supplemental sources. Commission staff determined that an extrapolation method similar to the one discussed above for advanced metering was not appropriate for demand response. Investments and activity in demand response are driven by a large number of factors entities face in power markets, including prevailing and projected wholesale electricity prices, level of available installed capacity, and the ability and interest of customers to participate in demand response programs. As a result, the extrapolation of regional patterns to individual entities would be problematic.

The primary method of developing peak load reduction estimates from this missing data (both from a lack of any response to the 2008 FERC Survey from an entity and to missing information regarding potential peak reduction for a demand response program in submitted responses) was to directly contact the entities to supply the missing data. If this was not possible, or direct contact was unsuccessful, information on total potential peak reduction reported by the entity in their 2006 EIA Form 861 submittal was used.[4] This process was applied to the largest entities with missing data who reported 100 MW of potential peak reductions in the 2006 EIA Form 861. RTO and ISO demand response evaluations and reports were also drawn upon where necessary, particularly potential peak reduction from curtailment service providers and unregulated retailers. As is seen in Table D-2, the response rate to the 2008 FERC Survey from curtailment service providers is low.

Commission staff and UtiliPoint also addressed double-counting of potential peak reduction. The 2008 FERC Survey was sent to entities that have the potential to report on the same demand response programs and rates. In the 2008 FERC Survey, Commission staff and their consultants identified 171 out of 2,315 reported demand response programs and rates that were reported by two or more entities. The double-counting was addressed by identifying a *Parent* and *Child* relationship for each duplicate program. For example, if a local distribution cooperative reported on a program and its cooperative generation and transmission (G&T) supplier also did, the *Child* would be the local cooperative and the *Parent* the G&T. The potential peak reduction and actual peak reduction was subtracted from the *Parent* in all identified cases. In developing an estimate of annual demand response resource contribution, eliminating this "double-counting" results in more accurate demand response potential values.

A final notable issue that is always present in surveys is data quality. A number of data quality checks were developed to assess reasonableness of survey responses on demand response resource potential. For example, a number of respondents did not notice that data about peak reduction and maximum demand of enrolled customers was requested in terms of megawatts and provided data in kilowatts.

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[4] This assumes that all the demand response programs/tariffs included in the EIA-861 survey in 2006 were continued without any changes in enrollment in 2005. Commission staff acknowledges that it is possible that a few entities may have discontinued the demand response programs/tariffs offered in 2006 by the time this report was complete.

Appendix E: FERC Survey Respondents

Municipally Owned Utilities (1041 Entities)

Adrian Public Utilities (MN)
Advance Municipal Light & Power (IN)
Aitkin Public Utilities Comm (MN)
Albany Water, Gas & Light Commission (GA)
Alexander City Light & Power (AL)
Alexandria, City of (MN)
Algoma Utilities (WI)
Anadarko Public Works Authority (OK)
Anderson Municipal Light and Power (IN)
Anita Municipal Utility (IA)
Anoka Municipal Utility (MN)
Ashburnham Municipal Light Plant (MA)
Ashland Electric (NH)
Atlantic Municipal Utilities (IA)
Aurelia Municipal Electric (IA)
Austin Energy (TX)
Austin Utilities (MN)
Azusa Light and Water (CA)
Bainbridge Municipal Electric Utility (IN)
Baldwin City Municipal Power/Light (KS)
Bamberg Board of Public Works (SC)
Bancroft Municipal (IA)
Barnesville Municipal Utility (MN)
Barron Light & Water (WI)
Barton Electric Dept. (VT)
Bay City Electric Light & Power (MI)
Beaches Energy Services (FL)
Belmont Light & Water (WI)
Benton Electric Utility (WI)
Biwabik Public Utilities (MN)
Black River Falls Municipal Utilities (WI)
Blakely Borough (PA)
Bloomer Electric & Water (WI)
Blue Earth Light & Water (MN)
Bluffton, City of (IN)
Board of Public Works (SC)
Board of Water Electric & Communications (IA)
Boro of Mont Alto (PA)
Borough of East Conemaugh (PA)
Borough of Ellwood City (PA)
Borough of Goldsboro (PA)
Borough of Grove City (PA)
Borough of Lavallette (NJ)
Borough of Milltown (NJ)
Borough of New Wilmington (PA)
Borough of Olyphant (PA)
Borough of Park Ridge (NJ)
Borough of Perkasie (PA)
Borough of Pitcairn (PA)
Borough of Smethport (PA)
Borough of Watsontown (PA)
Borough of Weatherly (PA)
Borough of Zelienople (PA)
Boscobel Utilities (WI)
Boylston Light (MA)
Bozrah Light & Power (CT)
Brainerd Public Utilities (MN)
Braintree Electric Light Department (MA)
Bremen Electric Light & Power Co. (IN)
Bridgeport, City of (TX)
Brigham City Corporation (UT)
Bristol Virginia Utilities (VA)
Brodhead Water & Light (WI)
Brooklyn Muni. Utilities (IA)
Brooklyn Municipal Electric Utility (IN)
Brownsville Public Utilities Board (TX)
Buffalo Iowa Municipal Power and Lighting Co (IA)
Burbank Water and Power (CA)
Butler Electric (NJ)
Cairo Public Utility Company (IL)
Canton Municipal Utilities (MS)
Carrollton Board of Public Works (MO)
Carthage Water & Electric Plant (MO)
Cascade Municipal Utilities (IA)
Cashton (WI)
Castroville Utility System (TX)
Cedarburg Light & Water Utility (WI)
Centerville Municipal Power & Light (IN)
Chappell Municipal Utilities (NE)
Charles P. Ketler Power Plant (NY)
Chester Municipal Electric Light Department (MA)
Chillicothe Municipal Utilities (MO)
City of Salisbury (MO)
City of Troy (MT)
City of Cavalier (ND)
City of Abbeville (LA)
City of Abbeville (SC)
City of Acworth (GA)
City of Ada (MN)
City of Adel (GA)
City of Afton (IA)
City of Akutan (AK)
City of Alameda (CA)
City of Albany (MO)
City of Albion (ID)
City of Alexandria (LA)
City of Algona (IA)
City of Alpha (MN)
City of Alta (IA)
City of Altamont (IL)
City of Altamont Kansas (KS)
City of Alton (IA)
City of Altus (OK)
City of Ames Electric Services (IA)
City of Anaheim, Public Utilities Department (CA)
City of Ansley (NE)
City of Anthony (KS)
City of Arapahoe (NE)
City of Arcadia (WI)
City of Arlington (MN)

Municipally Owned Utilities (Cont'd)

City of Arlington (SD)
City of Arma (KS)
City of Ashland (KS)
City of Ashland (OR)
City of Aspen (CO)
City of Attica (KS)
City of Auburn (IA)
City of Auburn (IN)
City of Aurora (SD)
City of Ava (MO)
City of Axtell (KS)
City of Aztec (NM)
City of Bandon (OR)
City of Banning (CA)
City Of Bardstown (KY)
City of Bartow (FL)
City of Bastrop (TX)
City of Batavia Elec Util (IL)
City of Baudette (MN)
City of Bedford (VA)
City of Belit (KS)
City of Bellville (TX)
City of Benson (MN)
City of Benton (AR)
City of Berea Municipal Utilities (KY)
City Of Beresford (SD)
City of Bethany (MO)
City of Biggs (CA)
City of Blackwell (OK)
City of Blaine Electric (WA)
City of Blakely (GA)
City of Bloomfield (IA)
City of Blooming Prairie (MN)
City of Boerne (TX)
City of Bonners Ferry (ID)
City of Boulder City (NV)
City of Bountiful (UT)
City of Bowie (TX)
City of Breckenridge (MN)
City of Breda (IA)
City of Breese (IL)
City of Brewster (MN)
City of Broken Bow (NE)
City of Bronson (KS)
City of Brookings (SD)
City of Brownfield (TX)
City of Brundidge (AL)
City of Bryan (OH)
City of Bryant (SD)
City of Buffalo (MN)
City of Buford (GA)
City of Buhl Minnesota (MN)
City of Burke (SD)
City of Burlington (CO)
City of Burlington (KS)
City of Burlington Electric Department (VT)
City of Burnet (TX)
City of Burwell (NE)
City of Bushnell (IL)
City of Cabool (MO)
City of Cascade Locks (OR)
City of Cairo (GA)
City of Calhoun (GA)
City of California (MO)
City of Callender (IA)
City of Cambridge (NE)
City of Camden, SC (SC)
City of Cameron (MO)
City of Camilla (GA)
City of Campbell (MO)
City of Carlyle (IL)
City of Carmi (IL)
City of Celina (OH)
City of Centralia (MO)
City of Centralia (WA)
City of Chanute (KS)
City of Charlevoix (MI)
City of Chattahoochee (FL)
City of Chefornak (AK)
City of Cheney (WA)
City of Chetopa (KS)
City of Chewelah (WA)
City of Chicopee (MA)
City of Cimarron (KS)
City of Clarkson (NE)
City of Clewiston (FL)
City of Cody (WY)
City of Colby (KS)
City of Coleman (TX)
City of College Station (TX)
City of Collinsville (OK)
City of Colman (SD)
City of Columbiana (OH)
City of Columbus, Ohio, Dept. of Pub Utilities (OH)
City of Commerce (GA)
City of Corona Department of Water & Power (CA)
City of Covington, GA (GA)
City of Crystal Falls (MI)
City of Cuero (TX)
City of Cumberland Municipal Utility (WI)
City of Cushing (OK)
City of Cuyahoga Falls (OH)
City of Danville (IA)
City of Danville (VA)
City of Darwin (MN)
City of Dayton (IA)
City of Doerun (GA)
City of Douglas (GA)
City of Dover (OH)
City of Deaver (WY)
City of Declo (ID)
City Of Delta (CO)
City of Deshler (NE)
City of Dike (IA)
City of Dowagiac (MI)
City of Drain (OR)
City of Duncan (OK)
City of Dunnell (MN)

Municipally Owned Utilities (Cont'd)

City of Durant (MS)
City of Dysart (IA)
City of Eaton Rapids (MI)
City of Eitzen (MN)
City of El Dorado Spgs. (MO)
City of Elba (AL)
City of Elberton (GA)
City of Elkhorn (WI)
City of Ellensburg (WA)
City of Ellsworth (IA)
City of Elroy (WI)
City of Enterprise (UT)
City of Erath (LA)
City of Escanaba (MI)
City of Escondido (CA)
City of Estherville (IA)
City of Eudora (KS)
City of Evergreen (AL)
City of Fairbank (IA)
City of Fairbury (NE)
City of Fairfax (MN)
City of Fairhope (AL)
City of Farmersville (TX)
City of Farmington (MO)
City of Farnhamville (IA)
City of Fayette (MO)
City of Flatonia (TX)
City of Floresville Electric Light & Power Sys (TX)
City of Fort Collins CO (CO)
City of Fosston (MN)
City of Franklin (VA)
City of Fredericksburg (IA)
City of Fredonia (AZ)
City of Friend (NE)
City of Galion Electric (OH)
City of Gallatin (MO)
City of Galt (MO)
City of Garden City (KS)
City of Gas City (IN)
City of Geneseo (Il
City of Geneva Municipal Electric Utility (IL)
City of Georgetown (TX)
City of Giddings (TX)
City of Gilbert (MN)
City of Gillette (WY)
City of Gilman City (MO)
City of Girard (KS)
City of Glasco (KS)
City of Glen Elder (KS)
City of Glenwood Springs (CO)
City of Glidden (IA)
City of Goldsmith (TX)
City of Gonzales (TX)
City of Goodland (KS)
City of Gothenburg (NE)
City of Grafton (ND)
City of Grand Haven (MI)
City of Grand Island (NE)
City of Grantville (GA)
City of Greendale (IN)
City of Greenfield (IA)
City of Greenville (TX)
City of Gridley (CA)
City of Griffin (GA)
City of Groton (SD)
City of Groton Dept of Utilities (CT)
City of Hampton (GA)
City of Hartford (AL)
City of Hartley (IA)
City of Haven (KS)
City of Healdsburg (CA)
City of Hearne (TX)
City of Hebron (NE)
City of Hecla (SD)
City of Helper (UT)
City of Hemphill (TX)
City of Hempstead (TX)
City of Herington (KS)
City of Hermann (MO)
City of Herndon (KS)
City of Heyburn (ID)
City of Higginsville (MO)
City of Hill City (KS)
City of Hillsboro (KS)
City of Hillsboro (ND)
City of Hinton (IA)
City of Hogansville (GA)
City of Hoisington (KS)
City of Holland Board of Public Works (MI)
City of Holyrood (KS)
City of Hominy (OK)
City of Hope (ND)
City of Houston (MO)
City of Hudson (OH)
City of Hugoton (KS)
City of Hunnewell (MO)
City of Huntingburg (IN)
City of Idaho Falls (ID)
City of Independence (MO)
City of Indianola (NE)
City of Iola (KS)
City Of Isabel (KS)
City of Jackson (GA)
City of Jackson (MN)
City of Jasper (TX)
City of Jewett City (CT)
City of Kahoka (MO)
City of Kansas City (KS)
City of Kaplan (LA)
City of Kasson (MN)
City of Key West (FL)
City of Kimball (NE)
City of Kings Mountain (NC)
City of Kirkwood (MO)
City of La Junta (CO)
City of Lacrosse (KS)
City of Lafayette (AL)
City of LaGrange, Ga (GA)

Municipally Owned Utilities (Cont'd)

City Of LaHarpe (KS)
City of Lake Crystal (MN)
City of Lake Mills (IA)
City of Lake View (IA)
City of Lakin (KS)
City of Lakota (ND)
City of Lamar (MO)
City of Lamar Utilities Board (CO)
City of Larned (KS)
City of Laurens (IA)
City of Laurens (SC)
City of Laurinburg (NC)
City of Lawler (IA)
City of Lawrenceville (GA)
City of Le Sueur (MN)
City of Lebanon (MO)
City of Lebanon (OH)
City of Leesburg (FL)
City of Lehigh (IA)
city of Leland (MS)
City of Lenox (IA)
City of Liberal (MO)
City of Lincoln Center (KS)
City of Lindsborg (KS)
City of Linneus (MO)
City of Linton (IN)
City of Livingston, TX (TX)
City of Llano (TX)
City of Lockhart (TX)
City of Lompoc (CA)
City of Longmont (CO)
City of Los Angeles (CA)
City of Loveland (CO)
City of Lubbock (TX)
City of Lucas (KS)
City of Luverne MN (MN)
City of Mabel (MN)
City of Maddock (ND)
City of Malden (MO)
City of Mangum (OK)
City of Mankato (KS)
City of Mansfield (GA)
City of Mansfield (MO)
City of Marathon (IA)
City Of Marceline (MO)
City of Marion (KS)
City of Marquette Board of Light and Power (MI)
City of Marshall (MI)
City of Marshall (MO)
City of Marshfield (WI)
City of Martinsville (VA)
City of Mascoutah (IL)
City of Mason (TX)
City of McCleary (WA)
City of McGregor (IA)
City of McLaughlin (SD)
City of McLeansboro (IL)
City of Meade (KS)
City of Medford (WI)
City of Melrose (MN)
City of Memphis (MO)
City of Mesa Utility Department (AZ)
City of Miami (OK)
City of Milford (DE)
City of Milford (IA)
City of Miller (SD)
City of Milton (WA)
City of Milton-Freewater (OR)
City of Minden (LA)
City of Minidoka (ID)
City of Mitchell (NE)
City of Monett (MO)
City of Monroe City (MO)
City of Monroe, NC (NC)
City of Montezuma Kansas (KS)
City of Monticello (GA)
City of Moorhead (MN)
City of Morgan City (LA)
City of Morgan City (UT)
City of Morrill (KS)
City of Mount Dora (FL)
City of Mount Vernon (MO)
City of Mountain Iron (MN)
City of Mountain View (MO)
City of Mt Pleasant (IA)
City of Mulvane (KS)
City of Naperville (IL)
City of Napoleon (OH)
City of Needles, California (CA)
City of Negaunee (MI)
City of Nelson (NE)
City of Neola (IA)
City of New Richmond (WI)
City of New Smyrna Beach (FL)
City of Newark (DE)
City of Newton Falls (OH)
City of Niles, MI (MI)
City of Nixa Utilities (MO)
City of Norcross, Ga. (GA)
City of North Saint Paul (MN)
City of Northwood (ND)
City of Norton (KS)
City of Norwich Dept of Public Utilities (CT)
City of Ocala Electric Utility (FL)
City of Odessa (MO)
City of Onawa (IA)
City of Onida (SD)
City of Opelika (AL)
City of Orange City (IA)
City of Orangeburg: Dpt of Public Utilities (SC)
City of Orrville (OH)
City Of Ortonville (MN)
City of Osage City (KS)
City of Osborne (KS)
City of Osceola (MO)
City of Oxford (KS)
City of Painesville (OH)
City of Palmetto (GA)

Municipally Owned Utilities (Cont'd)

City of Palmyra (MO)
City Of Paris (AR)
City of Paris (KY)
City of Parker (SD)
City of Pasadena (CA)
City of Paton (IA)
City of Pawhuska Oklahoma (OK)
City of Perry (MO)
City of Peterson (MN)
City of Petoskey (MI)
City of Pierce (NE)
City of Piggott (AR)
City of Pine Bluffs (WY)
City of Plainview Municipal Power Plant (NE)
City of Plankinton (SD)
City of Plummer (ID)
City of Pomona (KS)
City of Powell (WY)
City of Pratt (KS)
City of Prescott (AR)
City of Primghar (IA)
City of Providence (KY)
City of Pryor (OK)
City of Radford (VA)
City of Randall (MN)
City of Rayne (LA)
City of Readlyn (IA)
City of Red Bud (IL)
City of Redding (CA)
City of Richland (MO)
City of Richland (WA)
City of Riverdale (ND)
City of Rock Falls (IL)
City of Rock Hill (SC)
City of Round Lake (MN)
City of Rupert (ID)
City of Rushmore (MN)
City of Russell (KS)
City of Ruston (LA)
City of Sabetha (KS)
City of Saint Peter (MN)
City of Salem (VA)
City of San Marcos (TX)
City of Sandersville (GA)
City of Sanger (TX)
City of Savonburg (KS)
City of Schulenburg (TX)
City of Scranton (KS)
City of Scribner (NE)
City of Seaford (DE)
City of Seguin (TX)
City of Seneca (KS)
City of Seymour (TX)
City of Shelbina (MO)
City of Shelby (OH)
City of Shelly (MN)
City of Shiner (TX)
City Of Sibley (IA)
City of Sidney (NE)
City Of Siloam Springs (AR)
City of Sioux Falls (SD)
City of Smithville (TX)
City of South Sioux City (NE)
City of Southport (NC)
City of Spooner (WI)
City of Spring Grove (MN)
City of Springfield (CO)
City of Springfield, IL (IL)
City of St Paul (NE)
City of St. Charles Electric Department (MN)
City of St. Francis (KS)
City of St. George (UT)
City of St. Mary's (KS)
City of St. Mary's (OH)
City of St. Robert (MO)
City of Stafford (KS)
City of Stanhope (IA)
City of Starke (FL)
City of Steelville (MO)
City of Stephen (MN)
City of Stephenson (MI)
City of Stockton (KS)
City of Stratford (IA)
City of Strawberry Point (IA)
City of Stromsburg (NE)
City of Sullivan (MO)
City of Sutton (NE)
City of Sylvania (GA)
City of Tallahassee (FL)
City of Thayer (MO)
City of Toronto (KS)
City of Troy (AL)
City of Troy (KS)
City of Tulia (TX)
City of Two Harbors (MN)
City of Tyler (MN)
City of Tyndall (SD)
City of Udall (KS)
City of Ukiah (CA)
City of Union (SC)
City of Unionville (MO)
City of Valentine (NE)
City of Vermillion (SD)
City of Vero Beach (FL)
City of Vineland (NJ)
City of Virginia Dept of Public Utilities (MN)
City of Volga (SD)
City of Wadena (MN)
City of Wahoo Utilities (NE)
City Of Wakefield (MI)
City of Warroad (MN)
City of Waseca Electric Utility (MN)
City of Washington (KS)
City of Watertown (NY)
City of Watonga (OK)
City of Wauchula (FL)
City of Waynetown (IN)
City of Weimar (TX)

Municipally Owned Utilities (Cont'd)

City of Weiser (ID)
City of Wellington (KS)
City of Wells (MN)
City of Wessington Springs (SD)
City of West Bend (IA)
City of West Liberty (IA)
City of West Memphis (AR)
City of Westerville (OH)
City of Westfield (MA)
City of Whalan (MN)
City of Whigham (GA)
City of White (SD)
City of Whitesboro (TX)
City of Windom (MN)
City of Winfield (KS)
City of Winner (SD)
City of Winnfield (LA)
City of Winona (MO)
City of Winthrop (MN)
City of Woodbine (IA)
City of Woodsfield (OH)
City of Woolstock (IA)
City of Worthington Public Utilities (MN)
City of Wrangell (AK)
City Utilities of Richland Center (WI)
City Utilities of Springfield, Missouri (MO)
City Water and Light Plant (AR)
Clarksville Light & Water Col (AR)
Clay Center Public Utilities (KS)
Clinton Combined Utility Sys (SC)
Clintonville Utilities (WI)
Coatesville Power and Light (IN)
Coggon Municipal Light Plant (IA)
Col City Mun Elec Util (IN)
Colorado Springs City of (CO)
Columbia Water & Light Dept (MO)
Columbus Water & Light (WI)
Comanche Public Works Authority (OK)
Conway Corporation (AR)
Corbin City Utilities Commission (KY)
Corning Municipal Utilities (IA)
Corwith Municipal Utilities (IA)
CPS Energy (TX)
Crane Public Works (MO)
Cuba City Light & Water (WI)
Darlington Light & Power (IN)
David City Utilities (NE)
Deshler Municipal Utilities (OH)
Detroit Lakes Public Utility (MN)
Dublin Municipal Electric Utility (IN)
Durant Municipal Electric (IA)
Eagle River Light & Water Utility (WI)
Easton Utilities Commission (MD)
Edmond Electric (OK)
Elbow Lake Municipal Power (MN)
Electric Plant Board of Vanceburg (KY)
Elfin Cove Utility Comm. (AK)
Elk River Municipal Utilities (MN)
Ely Utilities (MN)
Emerson (NE)
Est Grand Forks, City of (MN)
Eugene Water & Electric Board (OR)
Evansville Water & Light (WI)
Fairburn Utilities (GA)
Fairview City Corporation (UT)
Falls City Utility Dept. (NE)
Fillmore City Corp (UT)
Fitzgerald Water, Light & Bond Commission (GA)
Florence Utilities (WI)
Floydada Power & Light (TX)
Forest City Municipal (IA)
Fort Morgan City of (CO)
Fort Pierce Utilities Authority (FL)
Fort Valley Utility Commission (GA)
Frankfort Electric and Water Plant (KY)
Fremont Department of Utilities (NE)
Gainesville Regional Utilities (FL)
Garland Power & Light (TX)
Geary Utilities Authority (OK)
Goltry P.W.A. (OK)
Gowrie Municipal Utilities (IA)
Grafton Electric (IA)
Granbury Municipal U. (TX)
Grand Rapids Public Utilities Commission (MN)
Granite (OK)
Green Cove Springs Electric Utility (FL)
Greenwich (OH)
Greenwood (NE)
Greenwood Utilities (MS)
Grove City (MN)
Grundy Center Municipal Light & Power (IA)
Hagerstown City of (IN)
Hagerstown Light Department (MD)
Halstad Municipal Utilities (MN)
Hannibal Board of Public Works (MO)
Harbor Springs Municipal Utility (MI)
Hardwick Electric Department (VT)
Harrisonburg Electric Commission (VA)
Hart Hydro (MI)
Hartford Electric (WI)
Hastings Utilities (NE)
Hawarden Municipal Utilities (IA)
Hawley Public Utilities (MN)
Heber Light & Power (UT)
Henderson City Utility Comm. (KY)
Hermiston Energy Services (OR)
Hooversville Borough (PA)
Hope Water and Light Commission (AR)
Hopkinton Municipal Utilities (IA)
Hull Municipal Light Plant (MA)
Hurricane City (UT)
Hustisford Utilities (WI)
Hyrum City Corp. (UT)
Inc. Village of Orleans (VT)
Incorporated County of Los Alamos (NM)
Independence Light, Power (IA)
Indianola Municipal Utilities (IA)
Ipnatchiaq Electric Co. (AK)

Municipally Owned Utilities (Cont'd)

Ipswich Municipal Light Department (MA)
Jackson Center Municipal Electric (OH)
Jamestown Board of Public Utilities (NY)
Jasper Municipal Utilities (IN)
JEA (FL)
Jefferson Utilities (WI)
Juneau Utilities (WI)
Kaukauna Utilities (WI)
Kaysville City Corporation (UT)
Keewatin Public Utilities (MN)
Kennebunk Light & Power District (ME)
Kenyon Municipal Utilities (MN)
Ketchikan Public Utilities (AK)
Kimballton Utilities (IA)
Kingman, City of (KS)
Kissimmee Utility Authority (FL)
Kosciusko Water & Light Plant (MS)
Lafayette Utilities System (LA)
Lake City Electric Utility (MN)
Lake Mills Utilities (WI)
Lake Placid Village, Inc. (NY)
Lamoni Municipal Utilities (IA)
Lansing Board of Water & Light (MI)
Las Animas Municipal Light and Power (CO)
Lehighton Borough (PA)
Levan Town Corporation (UT)
Lexington Public Works Authority (OK)
Lexington Utilities System (NE)
Light and Power Comm (MN)
Lincoln Electric System (NE)
Lindsay Public Work Authority (OK)
Litchfield Public Utilities (MN)
Littleton Electric Light (MA)
Lockwood Water and Light Company (MO)
Lodi Utilities (WI)
Logan City Light and Power (UT)
Logansport Municipal Utilities (IN)
Lowell Light and Power (MI)
Ludlow Electric (VT)
Lyons, Town of (CO)
Macon Municipal Utilities (MO)
Madelia Municipal Light & Power (MN)
Manilla Municipal Utilities (IA)
Manitowoc Public Utilities (WI)
Manning Municipal (IA)
Manti City (UT)
Mapleton Municipal electric (IA)
Maquoketa (IA)
Marblehead Municipal Light Department (MA)
Marietta Board of Lights and Water (GA)
Marshall Municipal Utilities (MN)
Marshallville Municipal Utilities (OH)
Matinicus Plantation Electrical Company (ME)
Mazomanie Utilities (WI)
McPherson City of (KS)
Memphis Light, Gas and Water Division (TN)
Menasha Utilities (WI)
Merrillan Municipal Water & Electric Utility (WI)
Merrimac Municipal Light Department (MA)
Middleborough Gas & Electric Department (MA)
Middletown Borough (PA)
Monroe City Corporation (UT)
Monroe Water, Light & Gas Comm (GA)
Montezuma Municipal Light & Power (IA)
Montezuma Municipal Utilities (IN)
Moose Lake Water & Light (MN)
Mount Horeb Utilities (WI)
Mt Pleasant City Power (UT)
Municipal Electric & Water (WI)
Municipal Utility (MN)
Municipal Utility (GA)
Murray City Power Department (UT)
Muscoda Utilities (WI)
Nephi City Corporation (UT)
New Braunfels Utilities (TX)
New Glarus Light & Water (WI)
New Hampton Village Precinct (NH)
New Holstein Utilities (WI)
New Knoxville Village of (OH)
New London Electric & Water Util (WI)
New Martinsville Municipal Electric Utility (WV)
New Prague Utilities Commission (MN)
New Ulm Public Utilities (MN)
Newkirk municipal Authority (OK)
Newton, City of (TX)
Nome Joint Utility System (AK)
North Attleborough Electric Department (MA)
North Branch Water & Light Municipal Utility (MN)
North Little Rock Electric Department (AR)
North Slope Borough Power & Light (AK)
Norway Power & Light (MI)
Oberlin (OH)
Oconomowoc Utilities (WI)
Oconto Falls Municipal Utilities (WI)
Ogden Municipal Utilities (IA)
Okeene Public Works Authority (OK)
Osage Municipal Utilities (IA)
Ottawa City of (KS)
Owatonna Public Utilities (MN)
Owensboro Municipal Utilities (KY)
Page Electric Utility (AZ)
Paragonah Town (UT)
Paris City of (MO)
Pascoag Utility District (RI)
Payson City (UT)
Peabody Municipal Light Plant (MA)
Pella Municipal Electric Utility (IA)
Pierre Municipal Utilities (SD)
Pioche Public Utility (NV)
Piqua Municipal Power System (OH)
Plattsburgh Municipal Lighting Department (NY)
PLWC (AR)
Plymouth Utilities (WI)
Portland Light and Power Board (MI)
Prague Public Works Authority (OK)
Prairie du Sac Utilities (WI)
Price Municipal Corporation (UT)
Princeton Municipal Light Department (MA)

Municipally Owned Utilities (Cont'd)

Princeton Public Utilities Comm (MN)
Proctor Public Utilities (MN)
Provo City Corporation (UT)
Public Works Comm-City of Fayetteville (NC)
PUD #1 of Asotin County (WA)
Reading Municipal Light Department (MA)
Reedsburg Utility Commission (WI)
Rensselaer Municipal Electric Utility (IN)
Renwick Municipal (IA)
Richmond Power and Light (IN)
River Falls Municipal Utilities (WI)
Riverside Public Utilities (CA)
Rochelle Municipal Utilities (IL)
Rochester Public Utilities (MN)
Rock Port Municipal Utilities (MO)
Rock Rapids Municipal Utilities (IA)
Rockford Municipal Light Plant (IA)
Rolla Municipal Utilities (MO)
Rowley Municipal Lighting Plant (MA)
Russell Municipal Electric Light (MA)
Saint Clair Borough Electric Light Department (PA)
Salamanca Board of Public Utilities (NY)
Sanborn Municipal Electric (IA)
Santa Clara City (UT)
Sauk City Electric & Water Department (WI)
Seattle City Light (WA)
Sebewaing (City of) (MI)
Shawano Municipal Utilities (WI)
Shrewsbury Electric and Cable Operations (MA)
Sikeston Board of Municipal Utilities (MO)
Sitka City & Borough of (AK)
Sleepy Eye Public Utilities (MN)
Slinger Utilities (WI)
South Hadley Electric Light Department (MA)
South Vienna Corporation (OH)
Spanish Fork City Corp (UT)
Spencer Municipal Utilities (IA)
Spring City Corporation (UT)
Spring Valley Public Utilities (MN)
Springfield Utility Board (OR)
Springville City Corp. (UT)
St James Municipal Utilities (MO)
St. Clairsville Light and Power (OH)
St. James Municipal (MN)
State Center Municipal (IA)
Stilwell Area Development Authority (OK)
Stoughton Utilities (WI)
Stowe Electric Department (VT)
Straughn Municipal Electric Corporation (IN)
Stuart Municipal Utilities (IA)
Sturgeon Bay Utilities (WI)
Sumner Municipal Light Plant (IA)
Sun Prairie Water & Light (WI)
Superior Utilities (NE)
Sylacauga Utilities Board (AL)
Tacoma, City of (WA)
Templeton Municipal Light & Water Plant (MA)
Texas Municipal Power Agency (TX)
The City of Holyoke Gas and Electric Dpt (MA)
The City of Quitman (GA)
Third Taxing District of the City of Norwalk (CT)
Thomasville Utilities (City of Thomasville GA) (GA)
Thorntown Utilities (IN)
Tipton Municipal Electric Utility (IN)
Tipton Municipal Utilities (IA)
Town of Avilla (IN)
Town of Black Creek (NC)
Town of Brookston (IN)
Town of Clayton (DE)
Town of Concord (MA)
Town of Crane (IN)
Town of Culpeper (VA)
Town of Due West (SC)
Town of Eldorado (OK)
Town of Enfield (NC)
Town of Forest City (NC)
Town of Fort Laramie (WY)
Town of Front Royal (VA)
Town of Granada (CO)
Town of Groveland (MA)
Town of Guernsey (WY)
Town of Haxtun (CO)
Town of Highlands (NC)
Town of Holly (CO)
Town of Jamestown (IN)
Town of Knightstown (IN)
Town of Ladoga (IN)
Town of Langford (SD)
Town of Laverne (OK)
Town of Lingle (WY)
Town of Lucama (NC)
Town of Lusk (WY)
Town of Mansfield Electric Department (MA)
Town of Massena Electric Department (NY)
Town of Northfield Electric Department (VT)
Town of Norwood (MA)
Town of Oak City (UT)
Town of Olustee (OK)
Town Of Paxton (MA)
Town of Pendleton (IN)
Town of Prosperity (SC)
Town of Readsboro Electric Department (VT)
Town of Sharpsburg (NC)
Town of Smithfield (NC)
Town of Smyrna (DE)
Town of South Coffeyville (OK)
Town of South Whitley (IN)
Town of Spiceland (IN)
Town of Springer (NM)
Town of Stantonsburg (NC)
Town of Steilacoom (WA)
Town of Sterling (MA)
Town of Summerfield (KS)
Town of Thatcher (AZ)
Town of Walstonburg (NC)
Town of Waynesville (NC)
Town of Wickenburg (AZ)
Town of Williamsport (MD)

Municipally Owned Utilities (Cont'd)

Town of Windsor (NC)
Town of Winnsboro (SC)
Town of Wolfeboro (NH)
Traer Municipal Utilities (IA)
Traverse City Light & Power (MI)
Trempealeau Municipal Electric Utility (WI)
Trenton Municipal Utilities (MO)
Truman Public Utilities (MN)
Turlock Irrigation District (CA)
Two Rivers Water & Light (WI)
Vandalia Power Plant (MO)
Village of Albany (IL)
Village of Andover (NY)
Village of Arcanum (OH)
Village of Baraga (MI)
Village of Bartley (NE)
Village of Bergen (NY)
Village of Bethel (OH)
Village of Black Earth (WI)
Village of Boonville (NY)
Village of Callaway (NE)
Village of Campbell (NE)
Village of Castile (NY)
Village of Centuria (WI)
Village of Daggett (MI)
Village of Davenport (NE)
Village of Decatur (NE)
Village of Dorchester (NE)
Village of Endicott (NE)
Village of Endicott (NY)
Village of Enosburg Falls Electric Department (VT)
Village of Fairport (NY)
Village of Frankfort (NY)
Village of Freeport (NY)
Village of Genoa (OH)
Village of Glouster (OH)
Village of Grafton (OH)
Village of Greene (NY)
Village of Gresham (WI)
Village of Groton (NY)
Village of Hamilton (NY)
Village of Hazel Green (WI)
Village of Hemingford (NE)
Village of Hilton (NY)
Village of Holbrook
Village of Holley (NY)
Village of Hyde Park, Inc. (VT)
Village of Jacksonville Electric Company (VT)
Village of Johnson Electric Company (VT)
Village of L'Anse (MI)
Village of Little Valley (NY)
Village of Lyndonville Electric Department (VT)
Village of Marathon Electric Department (NY)
Village of Minster (OH)
Village of Morrisville Water and Light Dpt (VT)
Village of New Bremen (OH)
Village of Oxford (NE)
Village of Panama (NE)
Village of Pardeeville (WI)
Village of Pemberville (OH)
Village of Prague (NE)
Village of Rantoul (IL)
Village of Reynolds (NE)
Village of Richmondville (NY)
Village of Rouses Point (NY)
Village of Seville (OH)
Village of Sherburne (NY)
Village of Snyder (NE)
Village of Spencerport (NY)
Village of Springville (NY)
Village of Stratford (WI)
Village of Stuart (NE)
Village of Talmage
Village of Tontogany (OH)
Village of Tupper Lake (NY)
Village of Walthill (NE)
Village of Waynesfield (OH)
Village of Wellington (OH)
Village of Wellsville Water & Light (NY)
Village of Winnetka (IL)
Village of Winside (NE)
Village of Yellow Springs (OH)
Vinton Municipal Electric Utility (IA)
Wagoner Public Works Authority (OK)
Walters Public Works Authority (OK)
Wampum Borough Electric (PA)
Washington City Corporation (UT)
Waterloo Utilities (WI)
Watertown Municipal Utilities (SD)
Waunakee Utilities (WI)
Waupun Utilities (WI)
Waverly Municipal Electric Utility (IA)
Weatherford Municipal Utility System (TX)
Wellesley Municipal Light Plant (MA)
West Boylston Municipal Light Plant (MA)
West Point Utility System (IA)
Westby Utilities (WI)
Whitehall Electric Utility (WI)
Williamstown Utility Commission (KY)
Wilton Municipal (IA)
Winamac Municipal Light & Power (IN)
Wonewoc Electric & Water Utility (WI)
Wynnewood City Utilities Authority (OK)
Zeeland Bd of Public Works (MI)

Cooperative Utilities (618 Entities)

Access Energy Coop (IA)
Adams Electric Coop (IL)
Adams Rural Electric (OH)
Adams-Columbia Electric Coop (WI)
Alaska Village Electric Coop (AK)
Albemarle Electric Membership Corporation (NC)
Alder Mutual Light Co., Inc. (WA)
Alfalfa Electric Coop, Inc. (OK)

Cooperative Utilities (Cont'd)

Alger Delta Coop Electric Association (MI)
Altamaha Electric Member Corp (GA)
Amicalola Electric Membership Corp (GA)
Anza Electric Coop, Inc. (CA)
Arizona Electric Power Coop, Inc. (AZ)
Ark Valley Electric Coop Assn., Inc. (KS)
Arkansas Electric Coop Corporation (AR)
Arkansas Valley Electric Coop Corporation (AR)
Arrowhead Electric Coop, Inc. (MN)
Ashley-Chicot Electric Coop, Inc. (AR)
Associated Electric Coop, Inc (MO)
Atchison-Holt Electric Coop (MO)
Bailey County Elec Coop Assn (TX)
Bandera Electric Coop, Inc. (TX)
Barry Electric Coop (MO)
Bartholomew County Rural E M C (IN)
Barton County Electric Coop, Inc. (MO)
Basin Electric Power Coop (ND)
Bayfield Electric Coop (WI)
Beartooth Electric Coop, Inc. (MT)
Beauregard Electric Co-op Inc (LA)
Belfalls Electric Coop Inc (TX)
Beltrami Electric Coop, Inc (MN)
Big Flat Electric Coop. (MT)
Big Horn County Electric Coop, Inc (MT)
Big Horn Rural Electric Co (WY)
Big Rivers Electric Corporation (KY)
Big Sandy Rural Elec Coop Corp (KY)
Blachly Lane County Coop Electric Assn (OR)
Black Hills Electric Coop, Inc. (SD)
Black Warrior Electric Member Corp (AL)
Blue Ridge Electric Membership Corporation (NC)
Bluestem Electric Coop, Inc. (KS)
Bon Homme Yankton Electric Assn., Inc. (SD)
Boone County Rural Electric Member Corp (IN)
Boone Electric Coop (MO)
Boone Valley Electric Coop (IA)
Bowie-Cass Electric Coop, Inc. (TX)
Brazos Electric Power Coop, Inc. (TX)
Bridger Valley Electric Association, Inc. (WY)
Broad River Electric Coop, Inc. (SC)
Brown Atchison Electric Coop Assn., Inc. (KS)
Brown County REA (MN)
Brunswick Electric Membership Corporation (NC)
Buckeye Power, Inc. (OH)
Buckeye Rural Electric Coop Inc (OH)
Burke-Divide Electric Coop (ND)
Butler County Rural Electric Coop (IA)
Butler Rural Electric Coop Assn., Inc. (KS)
Butler Rural Electric Coop, Inc. (OH)
Butte Electric Coop, Inc. (SD)
C & L Electric Coop Corporation (AR)
Caddo Electric Coop (OK)
Calhoun County Electric Coop Assn (IA)
Callaway Electric Coop (MO)
Cam Wal Electric Coop, Inc (SD)
Caney Valley Electric Coop Assn., Inc. (KS)
Canoochee Electric Member Corp (GA)
Cape Hatteras Electric Membership Corp (NC)
Capital Electric Coop, Inc. (ND)
Carbon Power & Light Inc (WY)
Carroll County REMC (IN)
Carroll Electric Coop Corporation (AR)
Carroll Electric Coop, Inc. (OH)
Carroll Electric Membership Corporation (GA)
Carteret-Craven El Member Corp (NC)
Cass County Electric Coop, Inc. (ND)
Cass Electric Coop (IA)
Cavalier Rural Electric Coop, Inc. (ND)
Central Electric Coop, Inc (OR)
Central Electric Membership Corporation (NC)
Central Electric Power Coop (MO)
Central Electric Power Coop, Inc. (SC)
Central Florida Electric Coop, Inc (FL)
Central Indiana Power (IN)
Central Iowa Power Coop (IA)
Central Montana Electric Power Coop (MT)
Central Rural Electric Coop (OK)
Central Texas Electric Coop, Inc. (TX)
Central Valley Electric Coop Inc. (NM)
Central Virginia Electric Coop (VA)
Central Wisconsin Electric Coop (WI)
Chariton Valley Electric Coop Inc. (IA)
Charles Mix Electric Association, Inc. (SD)
Chelco (FL)
Cherry Todd Electric Coop Inc. (SD)
Cherryland Electric Coop (MI)
Chippewa Valley Electric Coop (WIS)
Choptank Electric Coop, Inc. (MD)
Chugach Electric (AK)
Cimarron Electric Coop (OK)
Claiborne Electric Coop, Inc. (LA)
Clark County REMC (IN)
Clark Electric Coop (WI)
Clark Energy Coop, Inc. (KY)
Clarke Electric Coop, Inc (IA)
Clay Electric Co-operative, Inc. (IL)
Clearwater Power Company (ID)
Clearwater-Polk Electric Coop, Inc. (MN)
CMS Electric Coop., Inc. (KS)
Coahoma Electric Power Association (MS)
Coast Electric Power Association (MS)
Coastal Electric Coop (GA)
Cobb E M C - Pataula District (GA)
Cobb Electric Membership Corp (GA)
Codington-Clark Electric Coop, Inc. (SD)
Coleman County Electric Coop. Inc (TX)
Coles-Moultrie Electric Coop (IL)
Colquitt Electric Membership Corporation (GA)
Columbia Basin Electric Coop, Inc. (OR)
Columbus Electric Coop, Inc. (NM)
Comanche County Elec Coop Assn (TX)
Community Electric Coop (VA)
Co-Mo Electric Coop, Inc. (MO)
Concho Valley Elec Coop Inc (TX)
Concordia Electric Coop Inc (LA)
Connexus Energy (MN)
Consolidated Electric Coop (MO)

Cooperative Utilities (Cont'd)

Consumers Energy (IA)
Consumers Power, Inc. (OR)
Cookson Hills Electric Coop, Inc. (OK)
Coop Light and Power (MN)
Coosa Valley Electric Coop, Inc. (AL)
Coos-Curry Electric Coop, Inc. (OR)
Copper Valley Electric Association, Inc. (AK)
Cordova Electric Coop, Inc. (AK)
Corn Belt Energy Corporation (IL)
Corn Belt Power Coop
Covington Electric Coop, Inc. (AL)
Coweta-Fayette Electric Member Corp (GA)
Craig-Botetourt Electric Coop (VA)
Crow Wing Coop Power & Light Company (MN)
Cuivre River Electric Coop (MO)
Cumberland Valley Electric (KY)
Dairyland Power Coop (WI)
Dakota Electric Association (MN)
Dakota Energy Coop (SD)
Darke Rural Electric Coop. (OH)
Daviess-Martin County REMC (IN)
Deaf Smith Electric Coop, Inc. (TX)
Decatur County REMC (IN)
Deep East Texas Electric Coop, Inc. (TX)
Delaware Electric Coop, Inc. (DE)
Denton County Elec Coop, d/b/a CoServ Elec (TX)
Deseret Generation & Transmission Coop (UT)
Diverse Power Incorporated (GA)
Dixie Electric Coop (AL)
Dixie Electric Power Assn (MS)
Doniphan Electric Coop (KS)
Douglas Electric Coop Inc. (OR)
Douglas Electric Coop, Inc. (SD)
DS&O Rural Electric Coop Assn. Inc. (KS)
Dubois Rural Electric Coop, Inc. (IN)
Duncan Valley Electric Coop (AZ)
Dunn Energy Coop (WI)
East Kentucky Power Coop, Inc. (KY)
East River Electric Power Coop, Inc. (SD)
East Texas Electric Coop, Inc. (TX)
East-Central Iowa Rural Electric Coop (IA)
Eastern Illini Electric Coop (IL)
Eastern Iowa Light & Power Coop (IA)
Eastern Maine Electric Coop Inc. (ME)
Eau Claire Energy Coop
Edgecombe-Martin County E M C
Edisto Electric Coop, Inc.
Egyptian Electric Cooperative Association
Elmhurst
Empire Electric Association, Inc. (CO)
Energy Coop Association of Pennsylvania (PA)
EnergyUnited Electric Membership Corp (NC)
Excelsior Electric Member Corp (GA)
Fairfield Electric (SC)
Fall River Rural Electric Coop, Inc. (ID)
Farmers' Electric (NM)
Farmers Electric Co LTD (ID)
Farmers Electric Coop (IA)
Farmers Electric Coop Corp (AR)
Farmers Electric Coop, Inc (TX)
Farmers' Electric Coop, Inc. (MO)
Farmers Mutual Electric Co. (IL)
Farmers RECC (KY)
FEM Electric Assn., Inc (SD)
Fergus Electric Coop, Inc. (MT)
Firelands Electric Coop, Inc. (OH)
First Electric Coop Corporation (AR)
Flathead Electric Coop, Inc. (MT)
Flint Electric Membership Corporation (GA)
Flint Hills Rural Electric Coop Assn., Inc. (KS)
Florida Keys Electric Coop Assn. Inc. (FL)
Flowell Electric Association, Inc. (UT)
Fort Belknap Electric Coop, Inc. (TX)
Four County Elec Member Corp (NC)
Fox Islands Electric Coop, Inc. (ME)
Franklin Rural Electric Coop (IA)
French Broad Electric Membership Corp (NC)
Frontier Power Company (OH)
Fulton County REMC (IN)
Garakne Energy Coop, Inc. (UT)
Garland Light & Power Company (WY)
Gascosage Electric Coop (MO)
Georgia Transmission Corporation (GA)
Glacier Electric Coop, Inc (MT)
Glades Electric Coop, Inc. (FL)
Glidden Rural Electric Coop (IA)
Golden Spread Electric Coop, Inc. (TX)
Golden Valley Electric Association, Inc (AK)
Goldenwest Electric Coop, Inc. (MT)
Grady Electric Member Corp (GA)
Graham County Electric Coop, Inc. (AZ)
Grand Valley Power (CO)
Grayson Rural Electric (KY)
Grayson-Collin Electric Coop, Inc. (TX)
Great Lakes Energy Coop (MI)
Great River Energy (MN)
Greenbelt Electric Coop, Inc. (TX)
Grundy County Rural Elec Coop (IA)
Grundy Electric Coop, Inc. (MO)
Guernsey Muskingum EC (OH)
Gulf Coast Electric Coop, Inc. (FL)
Gunnison County Electric Association, Inc. (CO)
Guthrie Co REC (IA)
Habersham Electric Membership Corporation (GA)
Halifax Electric Member Corp (NC)
Hamilton County Electric Coop Association (TX)
Harney Electric Coop (OR)
Harrison County REMC (IN)
Harrison County Rural Electric Coop (IA)
Hart Electric Membership Corporation (GA)
Hawkeye REC (IA)
Haywood Electric Membership Corporation (NC)
H-D Electric Coop Inc. (SD)
Heart of Texas Electric Coop Inc (TX)
Heartland Power Coop (IA)
Heartland Rural Electric Coop, Inc. (KS)
Hendricks County Rural Elec Membership Coop (IN)
Henry County Rural Electric Membership Corp (IN)

Cooperative Utilities (Cont'd)

High Plains Power, Inc. (WY)
High West Energy (WY)
Highline Electric Association (CO)
HILCO Electric Coop, Inc. (TX)
Hill County Electric Coop, Inc. (MT)
Holmes-Wayne (OH)
Homer Electric Association (AK)
Hood River Electric Coop (OR)
Horry Electric Coop, Inc. (SC)
Houston County Electric Coop Inc. (TX)
Howard Electric Coop (MO)
Howell-Oregon Electric Coop, Inc. (MO)
Humboldt County Rural Electric Coop (IA)
Illinois Rural Electric Coop (IL)
Inland Power & Light Company (WA)
Intercounty Electric Coop Association (MO)
Iowa Lakes Electric Coop (IA)
Irwin Electric Membership Corporation (GA)
J-A-C Electric Co-op (TX)
Jackson County Rural Elec Membership Corp (IN)
Jackson Electric Coop (WI)
Jackson Electric Coop, Inc (TX)
Jackson Electric Member Corp (GA)
Jackson Energy Coop (KY)
Jasper-Newton Electric Coop, Inc. (TX)
Jefferson Davis Electric Coop, Inc. (LA)
Jefferson Energy Coop (GA)
Jemez Mountains Electric Coop, Inc. (NM)
Jo-Carroll Energy (IL)
Johnson County REMC (IN)
Jones-Onslow Electric Membership Corp (NC)
Jump River Electric Coop (WI)
K C Electric Association (CO)
KAMO Electric Coop, Inc. (OK)
Kandiyohi Power Coop (MN)
Kansas Electric Power Coop, Inc. (KS)
Kandiyohi Power Coop (MN)
Kansas Electric Power Coop, Inc. (KS)
Karnes Electric Coop Inc (TX)
Kauai Island Utility Coop (HI)
Kay Electric Coop (OK)
KEM Electric Coop, Inc. (ND)
Kenergy Corp. (KY)
Kiamichi Electric Coop, Inc. (OK)
Kingsbury Electric Coop, Inc. (SD)
Kiwash Electric Coop, Inc. (OK)
Kodiak Electric Association, INC. (AK)
Kosciusko REMC (IN)
La Plata Electric Association (CO)
Laclede Electric Coop (MO)
Lacreek Electric Association, Inc. (SD)
Lake Country Power (MN)
Lake Region Electric (SD)
Lake Region Electric Coop (MN)
Lake Region Electric Coop ~ Hulbert, OKLA (OK)
Lakeview Light & Power (WA)
Lamb County Electric Coop (TX)
Lane Electric Coop, Inc. (OR)
Lea County Electric Coop Inc. (NM)
Leavenworth-Jefferson Electric Coop, Inc. (KS)
Lee County Electric Coop, Incorporated (FL)
Licking Rural Electric Inc (OH)
Licking Valley Rural E C C (KY)
Lighthouse Electric Coop, Inc. (TX)
Linn County R E C A (IA)
Little Ocmulgee El Member Corp (GA)
Logan County Coop Power & Light Assn, Inc. (OH)
Lorain-Medina Rural Electric Coop, Inc. (OH)
Lost River Electric (ID)
Lower Yellowstone Rural Electric Assn Inc (MT)
Lumbee River Electric Membership Corp (NC)
Lynches River Electric Coop., Inc. (SC)
Lyntegar Electric Coop, Inc. (TX)
Lyon Rural Electric Coop (IA)
Lyon-Coffey Electric Coop, Inc. (KS)
Lyon-Lincoln Electric Coop, Inc. (MN)
M&A Electric Power Coop (MO)
Magic Valley Electric Coop, Inc. (TX)
Magnolia Electric Power Association (MS)
Marias River Electric Coop Inc (MT)
Marlboro Electric Coop (SC)
Marshall County REMC (IN)
McCone Electric Co-op. (MT)
McDonough Power Coop (IL)
McLean Electric Coop (ND)
McLennan County Elec Coop, Inc (TX)
Meade County RECC (KY)
Mecklenburg Electric Coop (VA)
Medina Electric Coop, Inc. (TX)
Meeker Coop Light and Power Association (MN)
Menard Electric Coop (IL)
Mid Carolina Elec Coop (SC)
Mid South Electric Coop Association (TX)
Midland Power Coop (IA)
Mid-Ohio Energy (OH)
Midstate Electric (OR)
Midwest Electric Coop Corporation (NE)
Midwest Electric Inc (OH)
Midwest Energy Coop (MI)
Midwest Energy, Inc. (KS)
Mid-Yellowstone Electric Coop, Inc. (MT)
Minnesota Valley Coop Light and Power Assn (MN)
Minnesota Valley Electric Coop (MN)
Minnkota Power Coop, Inc. (ND)
Mississippi County Electric Coop, Inc. (AR)
Missouri Rural Electric Coop (MO)
Monroe Co. Electric Coop (IL)
Moon Lake Electric Association Inc (UT)
Mora-San Miguel Electric Coop., Inc. (NM)
Moreau-Grand Electric Coop Inc (SD)
Morgan County Rural Electric Association (CO)
Mor-Gran-Sou Electric Coop, Inc. (ND)
Mountain Parks Electric, Inc. (CO)
Mountain View Electric Association (MVEA) (CO)
Mountrail-Williams EC (ND)
Mt. Wheeler Power (NV)
Mitchell Electric Membership Corp (GA)
Navarro Co Electric (TX)

Cooperative Utilities (Cont'd)

Navasota Valley Electric Coop (TX)
Navopache Electric Coop (AZ)
Nelson Lagoon Elec Coop Inc (AK)
Nemaha-Marshall Electric Coop Assn, Inc. (KS)
Nespelem Valley Electric Coop, Inc. (WA)
Nevada Irrigation District (CA)
Nevada Power Authority (CA)
New-Mac Electric Coop, Inc. (MO)
Newton County Rural E M C (IN)
NH Electric Coop (NH)
Ninnescah Rural Electric Coop (KS)
Niobrara Electric Association Inc (WY)
Nishnabotna Valley Rural Electric Coop (IA)
Noble County R.E.M.C. (IN)
Nobles Coop Electric (MN)
Nolin Rural Electric Coop Corporation (KY)
Norris Electric Coop (IL)
North Arkansas Electric Coop, Inc. (AR)
North Carolina El Member Corp (NC)
North Central Electric Coop, Inc. (ND)
North Central Electric Coop, Inc. (OH)
North Itasca Electric Coop (MN)
North Star Electric Coop Inc. (MN)
North West Rural Electric Coop (IA)
North Western Electric Coop Inc (OH)
Northeast Missouri Electric Power Coop (MO)
Northeast Oklahoma Electric Coop., Inc. (OK)
Northeast Texas Electric Coop, Inc. (TX)
Northern Electric Coop, Inc. (MT)
Northern Lights, Inc. (ID)
Northern Neck Electric Coop (VA)
Northern Rio Arriba (NM)
Northern Virginia Electric Coop (VA)
Northeastern REMC (IN)
Northwest Iowa Power Coop (IA)
Nushagak Coop Inc. (AK)
NW Electric Power Coop., Inc. (MO)
Oahe Electric Coop Inc (SD)
Oakdale Electric Coop (WI)
Ocmulgee Electric Membership Corporation (GA)
Oglethorpe Power Corporation (GA)
Ohop Mutual Light Company (WA)
Okanogan County Electric Coop (WA)
Oklahoma Electric Coop (OK)
Oliver-Mercer Electric Coop, Inc. (ND)
Oneida-Madison Electric Coop Inc. (NY)
Ontonagon County Rural Electrification Assn (MI)
Orcase Power & Light Coop (WA)
Oregon Trail Electric Consumers Coop, Inc. (OR)
Otero County Electric Coop, Inc. (NM)
Ouachita Electric Coop Corporation (AR)
Ozark Electric Coop, Inc. (MO)
Ozarks Electric Coop Corp (AR)
Pacific Northwest Generating Coop (OR)
Panola-Harrison Electric Coop, Inc. (TX)
Park Electric Coop Inc. (MT)
Parke County REMC (IN)
Paulding Putnam Electric Coop Inc. (OH)
Pea River Electric Coop (AL)
Pearl River Valley El Pwr Assn (MS)
Pedernales Electric Coop (TX)
Pee Dee Electric Coop, Inc. (SC)
Pee Dee Electric Membership Corp. (NC)
Pemiscot Dunklin Electric Coop (MO)
People's Coop Services (MN)
People's Electric Coop (OK)
Petit Jean Electric (AR)
Piedmont Electric Membership Corporation (NC)
Pierce Pepin Coop Services (WI)
Pioneer Electric Coop, Inc. (KS)
Pioneer Rural Electric Coop (OH)
Pitt & Greene Electric Member Corp (NC)
Planters Electric Membership Corporation (GA)
Platte Clay Electric Coop (MO)
Plumas-Sierra Rural Electric Coop (CA)
Pointe Coupee Electric Membership Corp (LA)
Poudre Valley Rural Electric Association (CO)
Powder River Energy Corporation (WY)
Power Resources Coop (OR)
PowerSouth Energy Coop (AL)
Prairie Land Electric Coop, Inc. (KS)
Prairie Power, Inc. (IL)
Price Electric Coop (WI)
Radiant Electric Coop (KS)
Raft River Rural Electric Coop, Inc. (ID)
Ralls County Electric Coop (MO)
Randolph Electric membership Corp. (NC)
Rappahannock Electric Coop (VA)
Ravalli Electric Coop, Inc. (MT)
Rayburn Country Electric Coop (TX)
Rayle Electric Membership Corporation (GA)
REA Energy Coop (PA)
Red Lake Electric Coop (MN)
Red River Valley Co-op Power Assoc. (MN)
Red River Valley Rural Electric Association (OK)
Redwood Electric Coop (MN)
Renville-Sibley Coop Power Assn. (MN)
Rich Mountain Electric Coop, Inc. (AR)
Richland Electric Coop (WI)
Rita Blanca Electric Coop Inc. (TX)
Riverland Energy Coop (WI)
Roanoke Electric Coop (NC)
Rolling Hills Electric Coop, Inc. (KS)
Roosevelt County Electric Coop, Inc. (NM)
Rosebud Electric Coop, Inc. (SD)
Rural Electric Coop, Inc (OK)
Rushmore Electric Power Coop (SD)
Rusk County Electric Coop, Inc. (TX)
Rutherford Electric Membership Corporation (NC)
Sac County Rural Electric Coop (IA)
Sac Osage Electric Coop, Inc. (MO)
Salem Electric (OR)
Salmon River Electric Coop, Inc. (ID)
Salt River Electric Coop. Corp. (KY)
Sam Rayburn G&T Electric Coop Inc. (TX)
San Luis Valley R E C, Inc (CO)
San Miguel Electric Coop (TX)
San Miguel Power Assn., Inc. (CO)

Cooperative Utilities (Cont'd)

San Patricio Electric Coop, Inc. (TX)
Santee Electric Coop, Inc (SC)
Sawnee Electric Member Corp (GA)
Scenic Rivers Energy Coop (WI)
Sedgwick County Electric Coop Assn., Inc. (KS)
Se-Ma-No Electric Coop (MO)
Seminole Electric Coop, Inc. (FL)
SEMO Electric Coop (MO)
Shelby Electric Coop (IL)
Shelby Energy Coop Inc (KY)
Shenandoah Valley Electric Coop (VA)
Sho-Me Power Electric Coop (MO)
Singing River Electric Power Association (MS)
Sioux Valley Southwestern Electric (SD)
Slash Pine Electric Membership Corporation (GA)
Slope Electric Coop (ND)
Smarr Electric Member Corp (GA)
Snapping Shoals Electric Membership Coop (GA)
South Alabama Electric Coop (AL)
South Central Arkansas Electric Coop, Inc. (AR)
South Central Electric Association (MN)
South Central Indiana REMC (IN)
South Central power Co. (OH)
South Kentucky Rural Electric Coop Corp (KY)
South Louisiana Electric Coop Association (LA)
South Mississippi Electric Power Association (MS)
South Plains Electric Coop Inc (TX)
South River Electric Membership Corporation (NC)
South Side Electric, Inc. (ID)
Southeast Colorado Power Association (CO)
Southeast Electric Coop (MT)
Southeastern Electric (OK)
Southeastern Electric Coop (SD)
SouthEastern Illinois Electric Coop, Inc. (IL)
Southern Illinois Power Coop (IL)
Southern Indiana REC, Inc. (IN)
Southern Iowa Electric Coop, Inc. (IA)
Southern Maryland Elec Coop Inc (MD)
Southern Pine Electric Power Association (MS)
Southside Electric Coop (VA)
Southside Electric Coop (VA)
Southwest Arkansas E C C (TX)
Southwest Electric Coop (MO)
Southwest Louisiana Electric Membership Corp (LA)
Southwest Mississippi Electric Power Assn (MS)
Southwest Rural Electric Association (OK)
Southwestern Electric Coop, Inc. (IL)
Southwestern Electric Coop, Inc. (NM)
Springer Electric Coop, Inc. (NM)
Square Butte Electric Coop (ND)
Stearns Electric Assn. (MN)
Steuben Rural Electric Coop, Inc. (NY)
Sulphur Springs Valley Electric Coop Inc (AZ)
Sumner-Cowley (KS)
Sumter Electric Coop, Inc. (FL)
Sumter Electric Membership Corporation (GA)
Sun River Electric Coop (MT)
Surprise Valley Electrification Corp. (CA)
Surry-Yadkin Elec Member Corp (NC)
Suwannee Valley Electric Coop, Inc. (FL)
Swans Island Electric Co-op Inc (ME)
Swisher Electric Coop. (TX)
SWTEC (TX)
T I P Rural Electric Coop (IA)
Tallapoosa River Electric Coop, Inc. (AL)
Talquin Electric Coop (FL)
Taylor County RECC (KY)
Tex-La Electric Coop-Texas Inc. (TX)
The Lane-Scott Electric Coop, Inc. (KS)
Three Notch Electric Member Corp (GA)
Three Rivers Electric Coop (MO)
Tideland Electric Member Corp (NC)
Todd-Wadena Electric Coop (MN)
Tombigbee Electric Coop (AL)
Tombigbee Electric Coop (AL)
Traverse Electric Coop, Inc. (MN)
Trico Electric Coop, Inc. (AZ)
Tri-County Electric Coop (MI)
Tri-County Electric Coop (MN)
Tri-County Electric Coop (OK)
Tri-County Electric Coop Association (MO)
Tri-County Electric Coop, Inc. (IL)
Tri-County Electric Coop, Inc. (TX)
Tri-County Electric Member Corp (GA)
Tri-County Electric Member Corp (NC)
Trinity Valley Electric Coop, Inc. (TX)
Tri-State G & T Assn, Inc (CO)
Twin County Electric Power Association (MS)
Twin Valley Electric Coop, Inc. (KS)
Umatilla Electric Coop (OR)
Unalakleet Valley Electric Coop, Inc. (AK)
Union County Electric Coop, Inc. (SD)
Union Electric Membership (NC)
Union Rural Electric Coop Inc (OH)
United Electric Co-op Inc. (ID)
United Electric Coop Services, Inc. (TX)
Upper Missouri G & T Electric Coop, Inc. (MT)
Upshur Rural Elec Coop Corp (TX)
Upson Electric Membership Corporation (GA)
Valley Electric Association, Inc. (NV)
Valley Electric Membership Corporation (LA)
Verdigris Valley Electric Coop (OK)
Vermont Electric Coop, Inc. (VT)
Victoria Electric Coop, Inc. (TX)
Victory Electric Coop Assn Inc (KS)
Vigilante Electric Coop, Inc (MT)
Wabash County REMC (IN)
Wake Electric Membership Corporation (NC)
Walton Electric Member Corp (GA)
Washington Electric Coop Inc NPCC (VT)
Washington Electric Membership Corporation (GA)
Washington-St.Tammany Electric Coop, Inc. (LA)
Webster Electric Coop (MO)
Wells Rural Electric Co. (NV)
West Central Electric Coop, Inc. (MO)
West Central Electric Coop, Inc. (MO)
West Florida Electric Coop Assn. Inc. (FL)
West Plains Electric Coop, Inc. (ND)

Cooperative Utilities (Cont'd)

West River Electric Association, Inc. (SD)
Western Coop Electric Association, Inc. (KS)
Western Farmers Electric Coop (OK)
Western Illinois Electrical Coop. (IL)
Western Indiana Energy REMC (IN)
Western Iowa Power Coop (IA)
Wharton County Electric Coop, Inc (TX)
Wheatland Electric Coop (KS)
White County REMC (IN)
White River Valley Electric Coop, Inc (MO)
Whitewater Valley REMC (IN)
Wild Rice Electric Coop (MN)
Wiregrass Electric Coop, Inc. (AL)
Withlacoochee River Electric Coop (FL)
Wolverine Power Marketing Coop (MI)
Wolverine Power Supply Coop, Inc. (MI)
Wood County Electric Coop, Inc (TX)
Woodbury County Rural ECA (IA)
Woodruff Electric Coop Corporation (AR)
Yazoo Valley EPA (MS)
Yellowstone Valley Electric Coop (MT)
York Electric Coop, Inc. (SC)

Investor Owned Utilities (189 Entities)

AEP Texas Central Company (TCC) (OH)
AEP Texas NorthCompany (OH)
Ajo Improvement Co. (AZ)
Alabama Power Company (AL)
Alaska Electric Light and Power Company (AK)
Alaska Power Company (AK)
Warrick Pwr Plant, AGC Div of Alcoa Pwr Gen (IN)
Alpena Power Company (MI)
Amana Society Service Company (IA)
Appalachian Power Co (WV)
Aquila Networks - Missouri (MO)
Aquila St. Joseph's Power (MO)
Aquila, Inc. (dba Aquila Networks-L&P) (CO)
Arizona Public Service co (AZ)
Atlantic City Electric Company (NJ)
Avista Corporation (ID)
Baltimore Gas and Electric Company (MD)
Bangor Hydro-Electric Company (ME)
Black Hills Power Inc (SD)
Cap Rock Energy Corp (TX)
CenterPoint (TX)
Central Electric Inc (AK)
Central Hudson Gas & Electric (NY)
Central Illinois Light Co (IL)
Central Illinois Public Service Co (IL)
Central Maine Power Company (ME)
Central Vermont Public Service Corporation (VT)
Cheyenne Light, Fuel & Power (WY)
Chitina Electric, Inc. (AK)
Citizens' Electric Company of Lewisburg, PA (PA)
Cleco Power, LLC (LA)
Cleveland Electric Illuminating Company (OH)
Columbus Southern Power Company (CSP) (OH)
Commonwealth Edison Company (IL)
Conectiv Atlantic Generation, LLC (NJ)
Conectiv Bethlehem, LLC (PA)
Conectiv Delmarva Generation, LLC (DE)
Connecticut Light and Power Company, The (CT)
Consolidated Edison Co of New York Inc. (NY)
Consolidated Water Power Company (WI)
Consumers Energy (MI)
Dahlberg Light and Power Company (WI)
Delmarva Power & Light Company (DE)
DTE Energy (MI)
Duke Energy Carolinas, LLC (NC)
Duke Energy Indiana (IN)
Duke Energy Kentucky (KY)
Duke Energy OH (OH)
Duquesne Light Company (PA)
Edison Sault Electric Company (MI)
Egegik Light & Power Company (AK)
Electric Energy, Inc. (IL)
Empire District Electric Company (MO)
Entergy Arkansas, Inc. (AR)
Entergy Gulf States Inc (TX)
Entergy Louisiana, LLC (LA)
Entergy Mississippi, Inc. (MS)
Entergy New Orleans, Inc. (LA)
Entergy Power, Inc. (AR)
EPE - TEXAS (TX)
Exelon Generation Company, LLC (PA)
Fale-Safe, Inc (OR)
Fishers Island Electric Co. (NY)
Fitchburg Gas and Electric Light Company (NH)
Florida Power & Light Company (FL)
Florida Public Utilities (FL)
G&K, Inc (AK)
Georgia Power Company (GA)
Golden State Water Company (CA)
Granite State Electric (NH)
Green Mountain Power Corp. (VT)
Gulf Power Company (FL)
Gustavus Electric Inc. (AK)
Hawaii Electric Light Company, Inc. (HI)
Hawaiian Electric (HI)
Holyoke Power and Electric Company (MA)
Holyoke Water Power Company (MA)
Idaho Power Company (ID)
Illinois Power Co (MO)
Indiana-Michigan Power Company (IN)
Indianapolis Power & Light Company (IN)
Interstate Power & Light Co. (IA)
Jersey Central Power & Light (NJ)
Kansas City Power & Light Company (MO)
Kentucky Power Company (KPCo) (KY)
Kentucky Utilities Company (KY)
KeySpan Generation, LLC (NY)
KG&E (KS)
Kingsport Power Company (OH)
Lockhart Power (SC)

Investor Owned Utilities (Cont'd)

Louisville Gas & Electric Company (KY)
Madison Gas and Electric Company (WI)
Maine Public Service Company (ME)
Manley Utility Co. Inc. (AK)
Mass Electric Co (MA)
Maui Electric Company, Ltd. (HI)
McGrath Light & Power (AK)
Metropolitan Edison Company (OH)
Miami Power Co (OH)
Minnesota Power Co (MN)
Mississippi Power (MS)
Monongahela Power Co (PA)
Montana-Dakota Utilities Co. (ND)
Mt. Carmel Public Utility Co. (IL)
Nantucket Electric Company (MA)
Napakiak Ircinraq Power Company (AK)
Nevada Power Company (NV)
New England Elec Transm'n Corp (NH)
New England Hydro-Tran Elec Co (MA)
New England Hydro-Trans Corp (NH)
New England Power Company (MA)
New York State Electric & Gas Corporation (NY)
Niagara Mohawk (NY)
North Central Power Co., Inc. (WI)
Northern Indiana Public Service Company (IN)
Northern States Power Company (MN)
Northern States Power Company (WI)
NorthWestern Energy (MT)
Northwestern Wisconsin Electric Company (WI)
NSTAR Electric (MA)
Ohio Edison Co (OH)
Ohio Power Company (OH)
Ohio Valley Electric Corporation (OH)
Omya Inc (VT)
Oncor Electric Delivery Company LLC (TX)
Orange & Rockland Utility Company (NY)
Otter Tail Power Company (MN)
Pacific Gas and Electric Company (CA)
PacifiCorp (OR)
PECO Energy Company (PA)
Pelican Utility District, Div of Kake Tribal Corp (AK)
Pennsylvania Electric Co (PA)
Pennsylvania Power Co (PA)
Pike County Light & Power Company (PA)
Portland General (OR)
Potomac Electric Power Company (DC)
PPL Electric Utilities (PA)
Progress Energy Carolinas, Inc. (NC)
Progress Energy Florida (FL)
Public Service Co of NM (NM)
Public Service Company of Colorado (CO)
Public Service Company of New Hampshire (NH)
Public Service Electric & Gas Company (NJ)
Public Service Oklahoma (PSO) (OK)
Puget Sound Energy, Inc (WA)
Redlands Water & Power Company (CO)
Rochester Gas and Electric Corporation (NY)
Rockland Electric Company (NY)
Safe Harbor Water Power Corporation (PA)
San Diego Gas & Electric (CA)
Sharyland Utilities, L.P. (TX)
Sierra Pacific Power Company (NV)
South Carolina Electric & Gas Co (SC)
South Carolina Generating Company, Inc (SC)
Southern California Edison Company (CA)
Southern Electric Gen Co (AL)
Oklahoma Gas and Electric Company (OK)
Southern Indiana Gas and Electric Co. (IN)
Southwestern Electric Power Company (LA)
Southwestern Public Service Company (TX)
Strawberry Water Users Association (UT)
Superior Water Light and Power (WI)
System Energy Resources, Inc. (MS)
Tampa Electric Company (FL)
TDX North Slope Generating (AK)
Texas New Mexico Power (TX)
The Dayton Power and Light Company (OH)
The Morenci Water and Electric Co. (AZ)
The Narragansett Electric Co (RI)
The Potomac Edison Co (MD),
The United Illuminating Company (CT)
Toledo Edison Co (OH)
TransCanada Power Div-Engy Ltd (CN)
Tucson Electric Power (AZ)
UGI Utilities, Inc. (PA)
Union Electric Company (MO)
Unitil Energy Systems, Inc. (NH)
UNS Electric (AZ)
Upper Peninsula Power Company (MI)
Vermont Yankee Nuclear Power Corp. (VT)
Virginia Electric & Power Co (VA)
Wellsboro Electric Company (PA)
West Penn Power Co (PA)
Westar Energy Inc (KS)
Western Massachusetts Electric Company (MA)
Wheeling Power Company(WPCo) (OH)
Wisconsin Electric Power Company (WI)
Wisconsin Power & Light Co. (WI)
Wisconsin Public Service Corporation (WI)

Power Marketers (96 Entities)

3 Phases Energy Services (CA)
Advantage Energy, Inc (NY)
Ameren Energy Marketing Company (MO)
APNA Energy (TX)
APS Energy Services Company, Inc. (AZ)
Avista Energy, Inc. (WA)
Avista Turbine Power, Inc. (WA)
BlueRock Energy inc (NY)
BP Energy Company (TX)
Calpine Power America, L.P. (TX)
Cargill Power Markets LLC (MN)
CECG Maine, LLC (MD)

Power Marketers (Cont'd)

Champion Energy Services, LLC (TX)
CinCap IV, LLC (OH)
CinCap V, LLC. (OH)
Cinergy Capital & Trading, Inc. (OH)
Cirro Group, Inc. (TX)
Citadel Energy Products LLC (DE)
City of Fulton (MO)
CL Power Sales Eight, L.L.C. (CA)
CL Power Sales Seven, L.L.C. (MA)
CL Power Sales Ten, L.L.C. (CA)
CL Power Sales Two, L.L.C. (CA)
Columbia Utilities Power, LLC (NY)
Conectiv Energy Supply, Inc. (DE)
ConocoPhillips (TX)
Constellation Energy Commodities Group, Inc. (MD)
Constellation NewEnergy, Inc. (MD)
Coral Power, L.L.C. (TX)
CP Power Sales Seventeen, L.L.C. (MA)
CPL Retail Energy (TX)
Direct Energy LP (TX)
Direct Energy Services (TX)
Dominion Retail, Inc. (CT)
Dow Hydrocarbons and Resources (TX)
DTE Energy Trading, Inc (MI)
Dynegy Power Marketing Inc. (TX)
Edison Mission Marketing & Trading, Inc. (MA)
El Dorado energy LLC (NV)
Empire Natural Gas Corporation (NY)
Energetix, Inc (NY)
Energy Coop of New York, Inc. (NY)
Energy West Resources, Inc. (MT)
Exelon Energy Company (PA)
FirstEnergy Solutions Corp. (OH)
FPL Energy Power Marketing, Inc. (FL)
Freedom Group (TX)
GEXA Corp. (TX)
Great Bay Power Marketing, Inc. (NH)
H.Q. Energy Services (U.S.) Inc. (PA)
Hwy 3 MHP, LLC (TX)
Integrys Energy Services of Texas, LP (TX)
KeySpan Energy Services Inc. (NY)
LG&E Energy Marketing (KY)
Mirant Energy Trading, LLC (GA)
MxEnergy Electric, Inc. (CT)
New York Industrial Energy Buyers, LLC (NY)
NM Energy of Texas, L.L.C. (TX)
NYSEG Solutions, Inc (NY)
OGE Energy Resources, Inc. (OK)
People's Electric Corporation (OK)
Peoples Energy Services (IL)
Pepco Energy Services (VA)
Pilot Power Group, Inc. (CA), (TX)
Pinnacle West Marketing & Trading Co., LLC (AZ)
Powerex Corp. (CN)
PPL EnergyPlus, LLC (PA)
PPM Energy (OR)
PreBuy Electric, LLC. (TX)
Pro Energy Marketing LLC (NY)
PSEG Energy Resources and Trade (NJ)
Quest Energy, LLC (MI)
Rainbow Energy Marketing Corporation (ND)
Reliant Energy Electric Solutions, LLC (TX)
Reliant Energy Power Supply, LLC (TX)
Reliant Energy Retail Services, LLC (TX)
Reliant Energy Services, Inc. (TX)
Reliant Energy Solutions East, LLC (TX)
Select Energy, Inc. (NJ), (NY)
Sempra Energy Solutions LLC (CA)
Sempra Energy Trading LLC (CT)
South Eastern Electric Development Corp (AL)
Star Electricity LLC dba StarTex Power (TX)
Strategic Energy LLC (PA)
Strategic Power Management, Inc. (NY)
Tara Energy, Inc. (TX)
Texas Retail Energy, LLC (TX)
TransAlta Energy Marketing (U.S.) Inc. (WA)
TransCanada Power Mktg Ltd (MA)
TXU Energy Retail Company LLC (TX)
TXU SESCO Energy Services Company (TX)
Vega Resources, LLC (TX)
Warrick Pwr Plant, AGC Div of Alcoa Pwr Gen (IN)
Williams Energy Mktg & Trdg Co (OK)
WPS Energy Services (WI)
WTU Retail Energy, LP (TX)

Political Subdivisions (91 Entities)

Aguila Irrigation District (AZ)
Alamo Power Dist #3 (NV)
Arkansas River Power Authority (CO)
Buckeye Water Consv and Drainage District (AZ)
Burt County Public Power District (NE)
Butler County Rural Public Power District (NE)
Central Lincoln People's Utility District (OR)
Central Minnesota Municipal Power Agency (MN)
City of New Roads (LA)
Clatckanie PUD (OR)
Columbia River PUD (OR)
Cornhusker Public Power District (NE)
Crisp County Power Commission (GA)
Cuming County Public Pwr Dist (NE)
DBA Tri-Dam Project (CA)
ED4 (AZ)
ED5 (AZ)
Electrical Dist No2 Pinal Cnty (AZ)
Electrical Dist No6 Pinal Cnty (AZ)
Electrical Dist No7 Maricopa (AZ)
Electrical Dist No8 Maricopa (AZ)
Electrical District No. 3 Pinal Cnty (AZ)
Electrical District No. 5 of Maricopa County
Elkhorn Rural Public Power District (NE)
Harquahala Valley Power District (AZ)
Heartland Consumers Power District (SD)
Hohokam Irr. & Dr. Dist. (AZ)
Howard Greeley Rural Public Power District (NE)

Political Subdivisions (Cont'd)

Igiugig Electric Company (AK)
KBR Rural Public Power District (NE)
Kings River Conservation Dist (CA)
Kokhanok Village Council (AK)
Lafayette Public Power Authority (LA)
Lincoln County Power District No. 1 (NV)
Loup River Public Power District (NE)
Loup Valleys Rural Public Power District (NE)
Maricopa Cnty Muni Wtr Consv District No. 1 (AZ)
Mason County PUD #3 (WA)
McCook Public Power District (NE)
McMullen Val Wtr Consv and Drainage District (AZ)
Merced Irrigation District (CA)
Modesto Irrigation District (CA)
Mohgan Tribal Utility Authority (CT)
MSR Public Power Agency (CA)
Municipal Energy Agency of Nebraska (NE)
Nebraska Public Power District (NE)
North Central Public Power District (NE)
Northeast Nebraska Public Power District (NE)
Northern California Power Agency (CA)
Northern Wasco County People's Utility Dist. (OR)
Northwest Rural Public Power District (NE)
Ocotillo Water Conservation District (AZ)
Omaha Public Power District (NE)
Overton Power District No. 5 (NV)
Perennial Public Power District (NE)
Piedmont Municipal Power Agency (SC)
Placer County Water Agency (CA)
Platte River Power Authority (CO)
Polk County RPPD (NE)
Public Utility District No. 1 of Chelan County (WA)
Public Utility District No. 1 of Wahkiakum Cnty (WA)
Public Utility District No. 2 of Grant County (WA)
Public Utility District No. 2 of Pacific County (WA)
Public Utility District #1 of Pend Oreille County (WA)
PUD No 1 of Clallam County (WA)
PUD No 1 of Douglas County (WA)
PUD No 1 of Ferry County (WA)
PUD NO 1 of Lewis County (WA)
PUD No 1 of Okanogan County (WA)
PUD No 1 of Whatcom County (WA)
PUD No. 1 of Grays Harbor County (WA)
Roosevelt Irrigation District (AZ)
Roosevelt Public Power District (NE)
Sacramento Municipal Utility District (CA)
Salt River Project (SRP) (AZ)
Seward County PPD (NE)
Skamania Public Utility District #1 (WA)
Snohomish County PUD #1 (WA)
South Central Public Power District (NE)
South Feather Water & Power Agency (CA)
Southern CA PPA (CA)
Southwest Public Power District (NE)
Stanton County Public Power District (NE)
The Central Nebraska Pub Pwr and Irr District (NE)
Tillamook People's Utility District (OR)
Tohono O'odham Utility Authority (AZ)
Truckee Donner Public Utility District (CA)
Tuolumne Public Power Agency (CA)
Utah Associated Municipal Power Systems (UT)
Wellton-Mohawk Irrigation & Drainage District (AZ)
Yakutat Power (AK)

Curtailment Service Providers (27 Entities)

Absolute Energy (NY)
Conservation Resource Solutions Inc. (GA)
Credit Suisse (USA), Inc. (NY)
Customized Energy Solutions, Ltd. (NJ), (PA)
Downes Associates, Inc. (MD)
Eastside Power Authority (ESPA) (CA)
Energy Curtailment Specialists, Inc. (NY)
Energy Enterprises Inc. (NY)
Energy Investment Systems (NY)
EnerNOC Inc. (MA)
EnerNOC, Inc. (CA)
GDS Associates, Inc. (NH)
Hess Corporation (NJ)
HSBC Bank USA (NY)
Integrated Energy Services Corporation (IES) (NJ)
Integrys Energy Services of New York, Inc (WI)
Lynx Technologies (NY)
Metropolitan Energy, LLC (IL)
Millard Fillmore Gates Hospital (NY)
Monroe County Water Authority (NY)
National Grid (MA)
Norbord (NY)
Reliant Energy Solutions Northeast, LLC (NY)
Suez Energy Resources NA (TX)
The Legacy Energy Group, LLC (VA)
UGI Energy Services, Inc. (PA)
Virtual Energy LLC (NY)

State Utilities (18 Entities)

Ak-Chin Energy Services (AZ)
Alaska Energy Authority (AK)
Brazos River Authority (TX)
California Energy Resource Scheduling (CA)
California Department of Water Resources (CA)
Colorado River Commission (NV)
Energy Northwest (WA)
Grand River Dam Authority (OK)
Guadalupe-Blanco River Authority (TX)
Lower Colorado River Authority (TX)
Michigan Public Power Agency (MI)
Navajo Tribal Utility Authority (AZ)
New River Light & Power Company (NC)
New York Power Authority (NY)

State Utilities (Cont'd)

OMPA (OK)
South Carolina Public Service Authority (SC)
Toledo Bend Project Joint Operation (TX)
Virginia Tech Electric Service (VA)

Municipal Marketing Authorities (15 Entities)

Alabama Municipal Electric Authority (AL)
American Municipal Power - Ohio, Inc. (OH)
Badger Power Marketing Auth (WI)
Hampshire Council of Governments (NH)
Indiana Municipal Power Agency (IN)
Kansas Municipal Energy Agency (KS)
Massachusetts Municipal Wholesale Elec Co (MA)
Minnesota Municipal Power Agency (MN)
Municipal Electric Authority of Georgia (GA)
New York Municipal Power Agency (NY)
Northern Municipal Power Agency (MN)
Utah Municipal Power Agency (UT)
Virginia Municipal Electric Association No 1 (VA)
Wisconsin Public Power, Inc. (WI)
Wyoming Municipal Power Agency (WY)

RTO/ISO (7 Entities)

California ISO (CA)
ERCOT (TX)
ISO New England (MA)
Midwest ISO (IN)
New York Independent System Operator (NY)
PJM Interconnection LLC (PA)
Southwest Power Pool, Inc. (AR)

Federal (6 Entities)

Bonneville Power Administration (OR)
Mission Valley Power (MT)
Southeastern Power Administration (GA)
Southwestern Power Administration (OK)
U. S. Army Corps of Engineers (MI)
VI Water & Power Authority (VI)

Appendix F: Demand Response (DR) Programs and Services at Responding Utilities

Appendix F is intended to convey a categorization of the types of demand response programs and services that are available in the entities that responded to the FERC survey.

Ancillary Services

HSBC Bank USA
Alabama Municipal Electric Authority
AGC Division of APG Inc
Arkansas Electric Cooperative Corporation
Austin Energy
Big Rivers Electric Corporation
Buckeye Power, Inc.
California ISO
Central Iowa Power Cooperative
City of Breckenridge
City of Chicopee
City of College Station
City of Corona Department of Water & Power
City of Elkhorn Light and Power
City of Milford
City of Redding
Connexus Energy
Constellation NewEnergy, Inc.
Cooperative Light and Power
Dakota Electric Association
Denton County Elec Coop, Inc
Detroit Lakes Public Utility
DS&O Rural Electric Cooperative Assn. Inc.
East Kentucky Power Cooperative, Inc.
Electrical District No. 3
EnerNOC, Inc.
Entergy Arkansas, Inc.
ERCOT
FirstEnergy Solutions Corp.
Florida Power Corp d/b/a Progress Energy Florida
Fulton County REMC
Golden Spread Electric Cooperative, Inc.
Great River Energy
Hawaiian Electric Company, Inc.
ISO New England
Jackson Electric Cooperative, Inc. (TX)
Kansas Electric Power Cooperative, Inc.
KG&E
Kiwash Electric Cooperative, Inc.
LADWP
Licking Rural Electrification
Lyon-Lincoln Electric Cooperative, Inc.
Mecklenburg Electric Cooperative
Millard Fillmore Gates Hospital
Minnkota Power Cooperative, Inc.
Monongahela Power Co
Mountain View Electric Association (MVEA)
MxEnergy Electric, Inc.
Nebraska Public Power District
New York Independent System Operator
Northern Indiana Public Service Company
Northern States Power Company - MN
NSTAR Electric
Pacific Gas and Electric Company
PacifiCorp
Pee Dee Electric Cooperative, Inc.
Piedmont Electric Membership Corporation
PJM Interconnection LLC
PowerSouth Energy Cooperative
Prairie Power, Inc.
Public Service Co. of New Mexico
Reliant Energy Solutions East, LLC
Rolling Hills Electric Cooperative, Inc.
Sacramento Municipal Utility District
SCE&G
Snohomish county PUD
South Carolina Public Service Authority
Southwest Public Power District
Southwestern Public Service Company
Suez Energy Resources NA
Tampa Electric Company
Tri-County Electric Cooperative, Inc.
Tri-State Generation and Transmission Assn, Inc.
TXU Energy Retail Company LLC
Vermont Electric Cooperative, Inc
Western Farmers Electric Cooperative
White County Rural E M C
Wisconsin Power & Light Co.
Wisconsin Public Service Corporation
Wolverine Power Supply Cooperative, Inc.

Capacity Market Programs

Alcoa Generating Corp. - Warrick
Arkansas Electric Cooperative Corporation
Baltimore Gas and Electric Company
Bangor Hydro-Electric Company
Big Rivers Electric Corporation
Brown County Rural Electrical Assn.
Buckeye Power, Inc.
California ISO
City of Breckenridge
City of Chicopee
City of College Station
City of Redding

Capacity Market Programs (Cont'd)

City of Waseca Electric Utility
Commonwealth Edison Company
Connecticut Light and Power Company
Consolidated Edison Co of NY, Inc
Constellation NewEnergy, Inc.
Dakota Electric Association
Duke Energy Indiana
Eastside Power Authority
Energy Curtailment Specialists, Inc.
EnerNOC, Inc.
ERCOT
Golden Spread Electric Cooperative, Inc.
Granite State Electric
Great River Energy
Green Mountain Power Corp
Hawaiian Electric Company, Inc
Hess Corporation
Horry Electric Cooperative, Inc.
HSBC Bank USA
Iowa Lakes Electric Cooperative
Jackson Electric Cooperative, Inc. (TX)
Kansas City Power & Light Company
Kansas Electric Power Cooperative, Inc.
Kiwash Electric Cooperative, Inc.
Mass Electric Co
Metropolitan Edison Co
Millard Fillmore Gates Hospital
Minnesota Valley Electric Cooperative
Minnkota Power Cooperative, Inc.
Modesto Irrigation District
Monongahela Power Co
New York Power Authority
New York State Electric & Gas Corporation
Niagara Mohawk
Norbord
North Itasca Electric Cooperative Inc.
North Itasca Electric Cooperative Inc.
NSTAR Electric
Pacific Gas and Electric Company
PacifiCorp
PECO Energy Company
PJM Interconnection LLC
PPL Electric Utilities
Public Service Co. of New Mexico
Rayle Electric Membership Corporation
Rochester Gas and Electric Corporation
Sacramento Municipal Utility District
South Kentucky Rural Electric Coop Corporation
Southern California Edison Company
Suez Energy Resources NA
The Narragansett Electric Co
Tri-County Electric Cooperative, Inc.
Tri-County Electric Cooperative, Inc.
Union County Electric Cooperative, Inc.
United Illuminating
Vermont Electric Cooperative, Inc
Vermont Marble Power Division of Omya Inc.
Virtual Energy LLC
Western Massachusetts Electric Company
Wisconsin Public Power, Inc.
Wisconsin Public Service Corporation

Critical Peak Pricing

HSBC Bank USA
Access Energy Cooperative
Alabama Municipal Electric Authority
Alabama Power Co
Alcoa Generating Corp. - Warrick
Arkansas Electric Cooperative Corporation
Beauregard Electric Co-op Inc.
Beltrami Electric Cooperative, Inc
Buckeye Power, Inc.
Butler Rural Electric Cooperative Assn., Inc. (KS)
Butler Rural Electric Cooperative, Inc. (OH)
Cherryland Electric Cooperative
Choptank Electric Cooperative, Inc.
City of Adel, Georgia
City of Fort Collins Co
City of Gothenburg
City of Grafton
City of Laurinburg North Carolina
City of Orangeburg ; Department of Public Utilities
City of Sylvania, GA
Colorado River Commission of Nevada
Colorado Springs Utilities
Colquitt Electric Membership Corporation
Commonwealth Edison Company
Consumers Energy Company (MI)
Downes Associates, Inc.
Duke Energy Carolinas
Duke Energy Indiana
Eau Claire Energy Cooperative
EnerNOC, Inc.
Flint Hills Rural Electric Cooperative Assn., Inc.
Fulton County REMC
Glidden Rural Electric Coop
Green Mountain Power Corp
Gulf Power Company
Gunnison County Electric Association, Inc.
Hendricks County Rural Electric Membership Coop
Horry Electric Cooperative, Inc.
Idaho Power Company
ISO New England
Jackson Electric Membership Corp. (GA)
Jefferson Energy Cooperative
Jemez Mountains Electric Cooperative, Inc.
Jump River Electric Cooperative
Kiamichi Electric Cooperative, Inc
Kiwash Electric Cooperative, Inc.
Kosciusko REMC
Leavenworth-Jefferson Electric Cooperative, Inc.
Licking Rural Electrification
Lyon-Lincoln Electric Cooperative, Inc.

Critical Peak Pricing (Cont'd)

Meeker Cooperative Light and Power Association
Midland Power Cooperative
Midwest Energy, Inc.
Millard Fillmore Gates Hospital.
Monongahela Power Co
Mountain Parks Electric, Inc.
Mountain View Electric Association (MVEA)
New York Independent System Operator
NH Electric Cooperative, Inc.
North Itasca Electric Cooperative Inc.
North Star Electric Cooperative Inc.
Oliver-Mercer Electric Cooperative, Inc.
Orange & Rockland Utilities
Otter Tail Power Company
Pacific Gas and Electric Company
Paulding Putnam Electric Cooperative, Inc.
PECO Energy Company
Pee Dee Electric Cooperative, Inc.
Pepco Energy Services
Pierce Pepin Cooperative Services
Potomac Electric Power Company
PPL Electric Utilities
Public Service Co. of New Mexico
Rayle Electric Membership Corporation
Red River Valley Co-op Power Assoc.
Red River Valley Rural Electric Association
Salt River Project (SRP)
San Diego Gas & Electric Company
Sawnee EMC
South Plains Electric Cooperative, Inc.
Southern California Edison Company
Southwest Louisiana Electric Membership Corp
Tampa Electric Company
Umatilla Electric Cooperative
Upper Peninsula Power Company
Village of Minster
Virginia Electric & Power Co
Wisconsin Public Service Corporation

Critical Peak Rebate

Butler Rural Electric Cooperative Assn., Inc. (KS)
Butler Rural Electric Cooperative, Inc. (OH)
City of Alpha
City of Breckenridge
City of Chicopee
City of Fort Collins Co
City of Friend
City of Grafton
City of Laurinburg North Carolina
City of Orangeburg ; Department of Public Utilities
Community Electric Cooperative
Connecticut Light and Power Company, The
Consolidated Edison Co of NY, Inc
Consumers Energy
Duke Energy Carolinas
First Electric Cooperative Corporation
Fulton County REMC
Horry Electric Cooperative, Inc.
Jersey Central Power & Light Co
KBR Rural Public Power District
Kiwash Electric Cooperative, Inc.
Lamb County Electric Cooperative
Mass Electric Co
Meeker Cooperative Light and Power Association
Midwest Electric Inc
Minnesota Power - Allete
Mississippi County Electric Cooperative, Inc.
Mountain View Electric Association (MVEA)
New York Power Authority
North Itasca Electric Cooperative Inc.
Omaha Public Power District
Potomac Electric Power Company
Public Service Co. of New Mexico
Red River Valley Co-op Power Assoc.
Reliant Energy Solutions East, LLC
Snohomish county PUD
South Plains Electric Cooperative, Inc.
Suez Energy Resources NA
The Narragansett Electric Co
Three Notch EMC
Western Massachusetts Electric Company

Demand Bidding

HSBC Bank USA
Access Energy Cooperative
Alcoa Generating Corp. - Warrick
Buckeye Power, Inc.
Butler Rural Electric Cooperative, Inc. (OH)
C & L Electric Cooperative Corporation
California ISO
Choptank Electric Cooperative, Inc.
City of Chicopee
City of Friend
City of Grafton
Colorado Springs Utilities
Connecticut Light and Power Company, The
Constellation NewEnergy, Inc.
Consumers Energy
Eastern Iowa light & Power Coop
EnerNOC, Inc.
Glidden Rural Electric Coop
Hess Corporation
Iowa Lakes Electric Cooperative
ISO New England
Kiwash Electric Cooperative, Inc.
Leavenworth-Jefferson Electric Cooperative, Inc.
Menard Electric Cooperative
Midwest Electric Inc
Millard Fillmore Gates Hospital

Demand Bidding (Cont'd)

Monongahela Power Co
Mor-Gran-Sou Electric Cooperative, Inc.
Nebraska Public Power District
New York Independent System Operator
New York Power Authority
Niagara Mohawk
Norbord
North Itasca Electric Cooperative Inc.
Northern States Power Company - MN
Omaha Public Power District
Pacific Gas and Electric Company
PJM Interconnection LLC
Portland General Electric Company
Public Service Co. of New Mexico
Red River Valley Co-op Power Assoc.
Sacramento Municipal Utility District
San Diego Gas & Electric Company
Snohomish county PUD
Southern California Edison Company
Suez Energy Resources NA
The Caney Valley Electric Coop Association, Inc.
Upper Peninsula Power Company
Western Massachusetts Electric Company
White River Valley Electric Cooperative, Inc
Wisconsin Electric Power Company
Wisconsin Public Service Corporation

Direct Load Control

Adams Electric Cooperative
Adams-Columbia Electric Cooperative
Alabama Power Co
Alfalfa Electric Cooperative, Inc.
Ashley-Chicot Electric Cooperative, Inc.
Austin Energy
Baltimore Gas and Electric Company
Barnesville Municipal Utility
Beltrami Electric Cooperative, Inc
Blue Ridge Electric Membership Corporation
Bon Homme Yankton Electric Assn., Inc.
Boone Electric Cooperative
Brown County Rural Electrical Assn.
Brunswick Electric Membership Corporation
Butler County Rural Electric Cooperative (IA)
Butler Rural Electric Cooperative Assn., Inc. (KS)
Butler Rural Electric Cooperative, Inc. (OH)
C & L Electric Cooperative Corporation
Capital Electric Cooperative, Inc.
Carroll Electric Cooperative Corporation (AR)
Carroll Electric Membership Corporation (GA)
Central Electric Membership Corporation
Central Maine Power Company
Central Minnesota Municipal Power Agency
Central Vermont Public Service Corporation
Central Wisconsin Electric Cooperative
Cherryland Electric Cooperative
Choptank Electric Cooperative, Inc.
City of Ames Electric Services
City of Anaheim
City of Benson Municipal Utilities
City of Breckenridge
City of Breda
City of Fort Collins Co
City of Friend
City of Grafton
City of Groton, SD
City of Hecla, SD
City of Laurinburg North Carolina
City of Loveland
City of Milford
City of Miller
City of Northwood
City of Parker, SD
City of Rock Hill
City of Saint Peter
City of Sylvania, GA
City of Waseca Electric Utility
City of Wells
City of Westerville
City of White, SD
Cleveland Electric Illuminating Co
Coles-Moultrie Electric Cooperative
Colorado Springs Utilities
Colquitt Electric Membership Corporation
Columbia Water & Light Dept
Commonwealth Edison Company
Community Electric Cooperative
Connexus Energy
Consolidated Edison Co of NY, Inc
Constellation NewEnergy, Inc.
Cooperative Light and Power
Corn Belt Energy Corporation
Coweta-Fayette EMC
Crow Wing Cooperative Power & Light Company
Cuivre River Electric Cooperative
Dahlberg Light and Power Company
Dairyland Power Cooperative
Dakota Electric Association
Dakota Energy Cooperative, Inc
Decatur County Rural Electric Membership Corp
Delaware Electric Cooperative, Inc.
Detroit Edison Co
Detroit Lakes Public Utility
DS&O Rural Electric Cooperative Assn. Inc.
Duke Energy Carolinas
Duke Energy Indiana
Duquesne Light Company
Eau Claire Energy Cooperative
Eau Claire Energy Cooperative
Elk River Municipal Utilities - City of Elk River
Empire Electric Association, Inc.
EnergyUnited Electric Membership Corporation
Excelsior Electric Membership Corporation (EMC)
Farmers Electric Cooperative Corporation (AR)
Farmers' Electric Cooperative, Inc. (MO)

Direct Load Control (Cont'd)

FEM Electric Assn., Inc
First Electric Cooperative Corporation
Florida Power & Light Company
Florida Power Corp d/b/a Progress Energy Florida
Fulton County REMC
Georgia Power Company
Grand Rapids Public Utilities Commission
Great Lakes Energy Cooperative
Hawaiian Electric Company, Inc
H-D Electric Cooperative, Inc.
Highline Electric Association
HomeWorks Tri-County Electric Cooperative
Horry Electric Cooperative, Inc.
Idaho Power Company
Illinois Rural Electric Cooperative
Indianapolis Power & Light Company
Jackson Electric Cooperative, Inc. (TX)
Jackson Electric Membership Corp. (GA)
JEA
Jefferson Energy Cooperative
Jersey Central Power & Light Co
Jump River Electric Cooperative
Kansas City Power & Light Company
KBR Rural Public Power District
Kentucky Utilities Company
Kiwash Electric Cooperative, Inc.
Kosciusko REMC
Lake Country Power
Lake Region Electric Cooperative
Lamb County Electric Cooperative
Leavenworth-Jefferson Electric Cooperative, Inc.
Lee County Electric Cooperative, Incorporated
Licking Rural Electrification
Logan City Light and Power
Louisville Gas & Electric Company
Lyon-Lincoln Electric Cooperative, Inc.
Madison Gas and Electric Company
Marshall Municipal Utilities
Mecklenburg Electric Cooperative
Medina Electric Cooperative, Inc.
Meeker Cooperative Light and Power Association
Menard Electric Cooperative
Midwest Electric Cooperative Corporation
Midwest Electric Inc
Midwest Energy Cooperative
Mid-Yellowstone Electric Cooperative, Inc.
Milton-Freewater City Light & Power
Minnesota Power – Allete
Minnesota Valley Electric Cooperative
Mississippi County Electric Cooperative, Inc.
Modesto Irrigation District
Montana-Dakota Utilities, Div of MDU Res Grp, Inc.
Mountain View Electric Association (MVEA)
Navopache Electric Cooperative, Inc.
Nevada Power
NH Electric Cooperative, Inc.
Nishnabotna Valley Rural Electric Cooperative
Nobles Cooperative Electric
Norbord
North Arkansas Electric Cooperative, Inc.
North Carolina Electric Cooperative
North Central Electric Cooperative, Inc.
North Itasca Electric Cooperative Inc.
North Star Electric Cooperative Inc.
North West Rural Electric Cooperative
Northeastern REMC
Northern Indiana Public Service Company
Northern States Power Company - MN
Northwest Rural Public Power District
Ocmulgee Electric Membership Corporation
Ohio Edison Co
Oliver-Mercer Electric Cooperative, Inc.
Otter Tail Power Company
PacifiCorp
PECO Energy Company
Petit Jean Electric Cooperative
Piedmont Electric Membership Corporation
Pierce Pepin Cooperative Services
Potomac Electric Power Company
Public Service Co. of New Mexico
Public Service Company of Colorado
Public Service Electric & Gas Company
Rappahannock Electric Cooperative
REA Energy Cooperative
Red River Valley Co-op Power Assoc.
Redwood Electric Coop
Renville-Sibley Coop Power
Rochester Public Utilities
Sacramento Municipal Utility District
Salamanca Board of Public Utilities
San Diego Gas & Electric Company
Sawnee EMC
Sedgwick County Electric Cooperative Assn., Inc.
Shelby Electric Cooperative
South Plains Electric Cooperative, Inc.
South River Electric Membership Corporation
Southern California Edison Company
Southern Indiana Gas and Electric Co.
Southern Maryland Electric Cooperative, Inc.
Southwest Public Power District
Spring Valley Public Utilities
Stearns Electric Association
Steuben Rural Electric Cooperative, Inc
Tampa Electric Company
The Toledo Edison Co
Three Notch EMC
Todd-Wadena Electric Cooperative
Town of Jamestown
Town of Massena Electric Department
Town of Smithfield
Trico Electric Cooperative, Inc.
Union County Electric Cooperative, Inc.
United Illuminating
Victory Electric Cooperative Assn, Inc.
Virginia Electric & Power Co
Wharton County Electric Cooperative
White County Rural E M C
Whitewater Valley REMC

Direct Load Control (Cont'd)

Wisconsin Electric Power Company
Wisconsin Power & Light Co.
Wisconsin Public Service Corporation
Woodbury County Rural ECA
Woodruff Electric Cooperative Corporation

Emergency Demand Response Program

Adams-Columbia Electric Cooperative
Alabama Municipal Electric Authority
Alabama Power Co
Alaska Electric Light and Power Company
Alcoa Generating Corp. - Warrick
Appalachian Power Company (APCo)
Arkansas Electric Cooperative Corporation
Baltimore Gas and Electric Company
Bozrah Light & Power
Buckeye Power, Inc.
Carroll Electric Membership Corporation (GA)
Central Electric Membership Corporation
Central Hudson Gas & Electric Corporation
Central Maine Power Company
Central Vermont Public Service Corporation
City of Alameda
City of Breckenridge
City of Brookings
City of Chicopee
City of Groton Dept of Utilities
City of Holland Board of Public Works
City of Laurinburg North Carolina
City of Sylvania, GA
City of Westerville
Cleveland Electric Illuminating Co
Colorado Springs Utilities
Columbus Southern Power Company (CSP)
Commonwealth Edison Company
Connecticut Light and Power Company, The
Connexus Energy
Consolidated Edison Co of NY, Inc
Constellation NewEnergy, Inc.
Cooperative Light and Power
Cuivre River Electric Cooperative
Dakota Electric Association
Denton County Elec Coop, Inc.
Detroit Edison Co
Downes Associates, Inc.
Duke Energy Indiana
Eastside Power Authority
Energy Curtailment Specialists, Inc.
EnerNOC, Inc.
ERCOT
Farmers' Electric Cooperative, Inc. (MO)
Florida Power Corp d/b/a Progress Energy Florida
Fulton County REMC
Georgia Power Company
Golden Spread Electric Cooperative, Inc.
Granite State Electric
Grayson RECC
Great Lakes Energy Cooperative
Hawaiian Electric Company, Inc
HSBC Bank USA
Idaho Power Company
Illinois Rural Electric Cooperative
Indiana-Michigan Power Company (I&M)
ISO New England
Kansas City Power & Light Company
KBR Rural Public Power District
Kentucky Power Company (KPCo)
Kentucky Utilities Company
Kingsport Power Company (KgPCo)
Kiwash Electric Cooperative, Inc.
Louisville Gas & Electric Company
Madison Gas and Electric Company
Mass Electric Co
Mecklenburg Electric Cooperative
Meeker Cooperative Light and Power Association
Millard Fillmore Gates Hospital
Milton-Freewater City Light & Power
Minnesota Valley Electric Cooperative
Mississippi County Electric Cooperative, Inc.
Monongahela Power Co
Montana-Dakota Utilities, Div of MDU Res Grp, Inc.
New York Independent System Operator
New York Industrial Energy Buyers, LLC
New York Power Authority
New York State Electric & Gas Corporation
Niagara Mohawk
Norbord
North Arkansas Electric Cooperative, Inc.
North Itasca Electric Cooperative Inc.
North Star Electric Cooperative Inc.
Northern States Power Company - MN
Northwestern Wisconsin Electric Company
NSTAR Electric
Ohio Edison Co
Ohio Power Company (OP)
Omaha Public Power District
Orange & Rockland Utilities
Otter Tail Power Company
Pacific Gas and Electric Company
PECO Energy Company
Pierce Pepin Cooperative Services
PJM Interconnection LLC
Potomac Electric Power Company
Prairie Power, Inc.
Public Service Co. of New Mexico
Public Service Company of Colorado
Public Service Oklahoma (PSO)
Rochester Gas and Electric Corporation
Rochester Public Utilities
Sacramento Municipal Utility District
San Diego Gas & Electric Company

Emergency Demand Response Program (Cont'd)

Shelby Electric Cooperative
South Plains Electric Cooperative, Inc.
Southern California Edison Company
Southern Maryland Electric Cooperative, Inc.
Southwestern Public Service Company
Stearns Electric Association
Steuben Rural Electric Cooperative, Inc
Suez Energy Resources NA
The Narragansett Electric Co
The Toledo Edison Co
Three Notch EMC
Town of Massena Electric Department
TXU Energy Retail Company LLC
Union County Electric Cooperative, Inc.
United Illuminating
Unitil Energy Systems, Inc.
Village of Minster
Virtual Energy LLC
Webster Electric Cooperative
Western Farmers Electric Cooperative
Western Massachusetts Electric Company
Wheeling Power Company (WPCo)
White County Rural E M C
White River Valley Electric Cooperative, Inc
Wisconsin Power & Light Co.

Interruptible and Curtailable

Access Energy Cooperative
Adams Electric Cooperative
Alabama Power Co
Alfalfa Electric Cooperative, Inc.
Alpena Power Company
Appalachian Power Company (APCo)
Aquila Inc. (dba Aquila Networks-L&P)
Baltimore Gas and Electric Company
Black Hills Power
Boone Electric Cooperative
Bozrah Light & Power
Brazos Electric Power Coop Inc
Brown County Rural Electrical Assn.
Brunswick Electric Membership Corporation
Carroll Electric Cooperative Corporation (AR)
Central Electric Membership Corporation
Central Illinois Light Company d/b/a AmerenCILCO
Central Illinois Public Service Co d/b/a AmerenCIPS
Central Maine Power Company
Central Valley Electric Cooperative Inc.
Central Vermont Public Service Corporation
Central Wisconsin Electric Cooperative
Cherryland Electric Cooperative
Choptank Electric Cooperative, Inc.
City of Breckenridge
City of Brookings
City of Chicopee
City of Friend
City of Grand Haven - Board of Light & Power
City of Groton Dept of Utilities
City of Holland Board of Public Works
City of McPherson Board of Public Utilities
City of Northwood
City of Rock Hill
City of Sylvania, GA
Cleveland Electric Illuminating Co
Coles-Moultrie Electric Cooperative
Colorado Springs Utilities
Colquitt Electric Membership Corporation
Columbia Water & Light Dept
Columbus Southern Power Company (CSP)
Commonwealth Edison Company
Community Electric Cooperative
Connecticut Light and Power Company, The
Connexus Energy
Consolidated Edison Co of NY, Inc
Constellation NewEnergy, Inc.
Conway Corporation
Cooperative Light and Power
Corn Belt Energy Corporation
Crow Wing Cooperative Power & Light Company
Cuivre River Electric Cooperative
Dakota Electric Association
Dakota Energy Cooperative, Inc
Decatur County Rural Electric Membership Corp
Delaware Electric Cooperative, Inc.
Denton County Elec Coop, Inc.
Detroit Edison Co
Duke Energy Carolinas
Duke Energy Indiana
Duquesne Light Company
Eastern Iowa light & Power Coop
Eau Claire Energy Cooperative
El Paso Electric Company/Texas
Elk River Municipal Utilities - City of Elk River
Empire District Electric Company
Energy Curtailment Specialists, Inc.
EnergyUnited Electric Membership Corporation
Entergy Arkansas, Inc.
FEM Electric Assn., Inc
First Electric Cooperative Corporation
Florida Power & Light Company
Florida Power Corp d/b/a Progress Energy Florida
Fulton County REMC
Glades Electric Cooperative, Inc.
Glidden Rural Electric Coop
Golden State Water Company
Granite State Electric
Grayson RECC
Great Lakes Energy Cooperative
Green Mountain Power Corp
Harrisonburg Electric Commission
Hawaii Electric Light Company, Inc.
Hawaiian Electric Company, Inc
H-D Electric Cooperative, Inc.
HomeWorks Tri-County Electric Cooperative

Interruptible and Curtailable (Cont'd)

Horry Electric Cooperative, Inc.
Illinois Power Company d/b/a AmerenIP
Illinois Rural Electric Cooperative
Indiana-Michigan Power Company (I&M)
Indianapolis Power & Light Company
Iowa Lakes Electric Cooperative
Jackson Electric Membership Corp. (GA)
JEA
Jefferson Energy Cooperative
Jersey Central Power & Light Co
Jump River Electric Cooperative
KBR Rural Public Power District
Kentucky Power Company (KPCo)
Kentucky Utilities Company
KG&E
Kiamichi Electric Cooperative, Inc
Kingsport Power Company (KgPCo)
Kissimmee Utility Authority
Kiwash Electric Cooperative, Inc.
Kosciusko REMC
LADWP
Lake Country Power
Lake Region Electric Cooperative
Leavenworth-Jefferson Electric Cooperative, Inc.
Lee County Electric Cooperative, Incorporated
Licking Rural Electrification
Linn County Rural Electric Cooperative Association
Louisville Gas & Electric Company
Lyon-Lincoln Electric Cooperative, Inc.
Madison Gas and Electric Company
Marshall Municipal Utilities
Mass Electric Co
Maui Electric Company, Ltd.
McLean Electric Cooperative, Inc.
Mecklenburg Electric Cooperative
Meeker Cooperative Light and Power Association
Menard Electric Cooperative
Metropolitan Edison Co
Midwest Electric Cooperative Corporation
Minnesota Power - Allete
Minnesota Valley Electric Cooperative
Mississippi Power
Modesto Irrigation District
Monongahela Power Co
Montana-Dakota Utilities, Div of MDU Res Grp, Inc.
Mountain Parks Electric, Inc.
Mountain View Electric Association (MVEA)
Navopache Electric Cooperative, Inc.
New York Power Authority
NH Electric Cooperative, Inc.
Nobles Cooperative Electric
Norbord
North Carolina Electric Cooperative
North Itasca Electric Cooperative Inc.
North Star Electric Cooperative Inc.
Northeastern REMC
Northern Indiana Public Service Company
Northern States Power Company - MN
Northwestern Wisconsin Electric Company
NSTAR Electric
Ocmulgee Electric Membership Corporation
Ohio Edison Co
Ohio Power Company (OP)
Oliver-Mercer Electric Cooperative, Inc.
Omaha Public Power District
Orange & Rockland Utilities
Otter Tail Power Company
Pacific Gas and Electric Company
PacifiCorp
Pee Dee Electric Cooperative, Inc.
Pennsylvania Electric Co
Piedmont Electric Membership Corporation
Pierce Pepin Cooperative Services
PPL Electric Utilities
Progress Energy Carolinas, Inc.
Public Service Co. of New Mexico
Public Service Company of Colorado
Public Service Company of New Hampshire
Public Service Electric & Gas Company
Public Service Oklahoma (PSO)
Rappahannock Electric Cooperative
REA Energy Cooperative
Red River Valley Rural Electric Association
Redwood Electric Coop
Reliant Energy Solutions, LLC
Richmond Power and Light
Rochester Public Utilities
Sacramento Municipal Utility District
Salamanca Board of Public Utilities
Salt River Project (SRP)
SCE&G
Sedgwick County Electric Cooperative Assn., Inc.
Shelby Electric Cooperative
South Carolina Public Service Authority
South Kentucky Rural Electric Coop Corporation
South Plains Electric Cooperative, Inc.
South River Electric Membership Corporation
SouthEastern Illinois Electric Cooperative, Inc.
Southern California Edison Company
Southern Indiana Gas and Electric Co.
Southwest Rural Electric Association
Southwestern Electric Cooperative, Inc.
Southwestern Public Service Company
Spencer Municipal Utilities
Stearns Electric Association
Suez Energy Resources NA
Sumter Electric Cooperative, Inc. (FL)
Tampa Electric Company
The Narragansett Electric Co
The Toledo Edison Co
Three Notch EMC
Todd-Wadena Electric Cooperative
Town of Massena Electric Department
Trico Electric Cooperative, Inc.
Tri-County EMC
TXU Energy Retail Company LLC
Union County Electric Cooperative, Inc.
Union Electric Company

Interruptible and Curtailable (Cont'd)

United Illuminating
Upper Peninsula Power Company
Utilities Commission, City of New Smyrna Beach, Fl
Victory Electric Cooperative Assn, Inc.
Village of Minster
Virginia Electric & Power Co (VA)
Virginia Electric & Power Co (NC)
Virtual Energy LLC
Waverly Municipal Electric Utility
Webster Electric Cooperative
Wheatland Electric Cooperative
Wheeling Power Company (WPCo)
Wisconsin Electric Power Company
Wisconsin Power & Light Co.
Wisconsin Public Power, Inc.
Wisconsin Public Service Corporation
Woodbury County Rural ECA

Real-Time Pricing

Alabama Power Co
Alpena Power Company
Aquila Inc. (dba Aquila Networks-L&P)
Baltimore Gas and Electric Company
Bon Homme Yankton Electric Assn., Inc.
Central Hudson Gas & Electric Corporation
Central Illinois Light Company d/b/a AmerenCILCO
Central Illinois Public Service Co d/b/a AmerenCIPS
Central Vermont Public Service Corporation
City of Adel, Georgia
City of Chicopee
City of Covington, GA
City of Gothenburg
City of Groton Dept of Utilities
City of Laurinburg North Carolina
City of Sylvania, GA
Cleveland Electric Illuminating Co
Colorado River Commission of Nevada
Colorado Springs Utilities
Commonwealth Edison Company
Consolidated Edison Co of NY, Inc
Constellation NewEnergy, Inc.
Consumers Energy Company (MI)
Crisp County Power Commission
Decatur County Rural Electric Membership Corp
DS&O Rural Electric Cooperative Assn. Inc.
Duke Energy Carolinas
Duke Energy Indiana
Duquesne Light Company
Eastside Power Authority
Energetix, Inc
Entergy Arkansas, Inc.
FirstEnergy Solutions Corp.
Georgia Power Company
Gulf Power Company
Hampshire Council of Governments
Hess Corporation
HomeWorks Tri-County Electric Cooperative
Illinois Power Company d/b/a AmerenIP
Indianapolis Power & Light Company
Jackson Electric Cooperative, Inc (TX)
Jefferson Energy Cooperative
Jersey Central Power & Light Co
Kansas City Power & Light Company
Kentucky Power Company (KPCo)
KG&E
Leavenworth-Jefferson Electric Cooperative, Inc.
Licking Rural Electrification
Logan City Light and Power
Lyon-Lincoln Electric Cooperative, Inc.
Minnesota Power - Allete
Minnesota Valley Electric Cooperative
Monongahela Power Co
Mount Horeb Utilities
Mountain Parks Electric, Inc.
Mountain View Electric Association (MVEA)
MxEnergy Electric, Inc.
New York Power Authority
New York State Electric & Gas Corporation
Niagara Mohawk
Norbord
Northern States Power Company - MN
NYSEG Solutions, Inc
Ohio Edison Co
Orange & Rockland Utilities
Otter Tail Power Company
Paulding Putnam Electric Cooperative, Inc.
PECO Energy Company
Pepco Energy Services
Portland General Electric Company
Potomac Electric Power Company
PPL Electric Utilities
Progress Energy Carolinas, Inc.
Public Service Company of New Hampshire
Public Service Electric & Gas Company
Public Service Oklahoma (PSO)
Red River Valley Rural Electric Association
Reliant Energy Retail Services, LLC
Reliant Energy Solutions East, LLC
Reliant Energy Solutions, LLC
Rochester Gas and Electric Corporation
Rolling Hills Electric Cooperative, Inc.
SCE&G
Snohomish county PUD
South Carolina Public Service Authority
Southern California Edison Company
Suez Energy Resources NA
Tampa Electric Company
Templeton Municipal Light & Water Plant
The Toledo Edison Co
TXU Energy Retail Company LLC
Union County Electric Cooperative, Inc.
Upper Peninsula Power Company
Vermont Electric Cooperative, Inc
Vermont Marble Power Division of Omya Inc.
Victory Electric Cooperative Assn, Inc.

Real-Time Pricing (Cont'd)

Virginia Electric & Power Co
Wheatland Electric Cooperative
Wisconsin Public Power, Inc.

Time-of-Use

Adams Electric Cooperative
Adams-Columbia Electric Cooperative
Alabama Power Co
Alaska Electric Light and Power Company
Algoma Utilities
Alpena Power Company
Appalachian Power Company (APCo)
Aquila Inc. (dba Aquila Networks-L&P)
Arizona Public Service (APS)
Austin Energy
Azusa Light and Water
Bangor Hydro-Electric Company
Bartholomew County Rural EMC
Bay City Electric Light & Power
Beauregard Electric Co-op Inc.
Belfalls Electric Cooperative Inc
Big Horn Rural Electric Company
Black Hills Power
Black River Falls Municipal Utilities
Blue Ridge Electric Membership Corporation
Bon Homme Yankton Electric Assn., Inc.
Bremen Electric Light & Power Co.
Bristol Virginia Utilities
Brodhead Water & Light
Brunswick Electric Membership Corporation
Burbank Water and Power
Butler County Rural Electric Cooperative (IA)
Butler Rural Electric Cooperative, Inc. (OH)
Carbon Power & Light Inc
Cedarburg Light & Water Utility
Central Florida Electric Cooperative, Inc.
Central Hudson Gas & Electric Corporation
Central Maine Power Company
Central Rural Electric Cooperative
Central Vermont Public Service Corporation
Central Wisconsin Electric Cooperative
CHELCO
Cherryland Electric Cooperative
Choptank Electric Cooperative, Inc.
City of Adel, Georgia
City of Anaheim
City of Banning
City of Brookings
City of Burlington Electric Department
City of Bushnell
City of College Station
City of Corona Department of Water & Power
City of Covington, GA
City of Douglas
City of Elkhorn Light and Power
City of Gothenburg
City of Grand Haven - Board of Light & Power
City of Laurinburg North Carolina
City of Marshfield
City of McPherson Board of Public Utilities
City of Medford
City of Mountain Iron
City of Ocala Electric Utility
City of Orangeburg ; Department of Public Utilities
City of Paris
City of Redding
City of Rock Hill
City of Salem, VA
City of St Mary's
City of Westfield
City Utilities of Richland Center
Clark County REMC
Clark Energy Cooperative, Inc.
Clarke Electric Cooperative, Inc
Cleveland Electric Illuminating Co
CMS Electric Cooperative, inc.
Colorado River Commission of Nevada
Colorado Springs Utilities
Columbia Water & Light Dept
Columbus Southern Power Company (CSP)
Columbus Water & Light
Commonwealth Edison Company
Connecticut Light and Power Company, The
Connexus Energy
Consumers Energy Company (MI)
Consumers Energy (IA)
Coweta-Fayette EMC
Crisp County Power Commission
Crow Wing Cooperative Power & Light Company
Cuba City Light & Water
Cumberland Valley Electric
Dahlberg Light and Power Company
Dakota Electric Association
Decatur County Rural Electric Membership Corp
Delaware Electric Cooperative, Inc.
Denton County Elec Coop, Inc.
Detroit Lakes Public Utility
DS&O Rural Electric Cooperative Assn. Inc.
Duke Energy Carolinas
Duke Energy Indiana
Eagle River Light & Water Utility
Eastern Iowa light & Power Coop
Eau Claire Energy Cooperative
Edison Sault Electric Company
El Paso Electric Company/Texas
Electrical District No. 3
Empire Electric Association, Inc.
Energetix, Inc
Entergy Arkansas, Inc.
Evansville Water & Light
Fall River Rural Electric Coop, Inc.
Farmers RECC
FEM Electric Assn., Inc

Time-of-Use (Cont'd)

Flint Hills Rural Electric Cooperative Assn., Inc.
Florence Utilities
Florida Power & Light Company
Florida Power Corp d/b/a Progress Energy Florida
Franklin Rural Electric Cooperative
Gainesville Regional Utilities
Georgia Power Company
Glades Electric Cooperative, Inc.
Golden State Water Company
Grand River Dam Authority
Grand Valley Power
Granite State Electric
Grayson RECC
Green Mountain Power Corp
Gulf Power Company
Gunnison County Electric Association, Inc.
Harrison County REMC Inc.
Hartford Electric
Hawaii Electric Light Company, Inc.
Hawaiian Electric Company, Inc
High Plains Power, Inc.
High West Energy, Inc
Highline Electric Association
HomeWorks Tri-County Electric Cooperative
Hustisford Utilities
Idaho Power Company
Indiana-Michigan Power Company (I&M)
Indianola Municipal Utilities
Iowa Lakes Electric Cooperative
Jackson Electric Cooperative, Inc (TX)
Jackson Electric Membership Corp. (GA)
JEA
Jefferson Energy Cooperative
Jefferson Utilities
Jemez Mountains Electric Cooperative, Inc.
Jersey Central Power & Light Co
Johnson County REMC
Juneau Utilities
Kansas City Power & Light Company
Kaukauna Utilities
Kentucky Power Company (KPCo)
Kentucky Utilities Company
KG&E
Kingsport Power Company (KgPCo)
Kissimmee Utility Authority
Kosciusko REMC
LADWP
Lake Country Power
Lake Mills Utilities
Leavenworth-Jefferson Electric Cooperative, Inc.
Lexington Utilities System
Linn County Rural Electric Cooperative Association
Lodi Utilities
Logan City Light and Power
Louisville Gas & Electric Company
Lyon-Lincoln Electric Cooperative, Inc.
Madison Gas and Electric Company
Magic Valley Electric Cooperative
Manitowoc Public Utilities
Mass Electric Co
Maui Electric Company, Ltd.
Meade County RECC
Medina Electric Cooperative, Inc.
Metropolitan Edison Co
Midland Power Cooperative
Midwest Electric Cooperative Corporation
Midwest Energy Cooperative
Midwest Energy, Inc.
Mid-Yellowstone Electric Cooperative, Inc.
Mississippi Power
Montana-Dakota Utilities, Div of MDU Res Grp, Inc.
Morgan County Rural Electric Association
Mount Horeb Utilities
Mountain Parks Electric, Inc.
Mountain View Electric Association (MVEA)
Muscoda Utilities
Navopache Electric Cooperative, Inc.
Nebraska Public Power District
Nevada Power
New Braunfels Utilities
New Glarus Light & Water
New Holstein Utilities
New London Utilities
New Richmond Utilities
New York Power Authority
New York State Electric & Gas Corporation
Niagara Mohawk
North Carolina Electric Cooperative
North Central Power Co., Inc.
North Little Rock Electric Department
Northeastern REMC
Northern Indiana Public Service Company
Northern Rio Arriba Electric
Northern States Power Company - MN
Northwest Rural Public Power District
Northwestern Wisconsin Electric Company
NSTAR Electric
NYSEG Solutions, Inc
Oconomowoc Utilities
Oconto Falls Municipal Utilities
Ohio Edison Co
Ohio Power Company (OP)
Oklahoma Electric Cooperative
Omaha Public Power District
Orange & Rockland Utilities
Orcas Power & Light Cooperative
Otero County Electric Cooperative, Inc.
Otter Tail Power Company
Pacific Gas and Electric Company
PacifiCorp
Parke County REMC
Peabody Municipal Light Plant, City of Peabody
PECO Energy Company
Pee Dee Electric Cooperative, Inc.
Pennsylvania Electric Co
Peoples Energy Services
Piedmont Electric Membership Corporation
Pioneer Rural Electric Cooperative

Time-of-Use (Cont'd)

Plymouth Utilities
Portland General Electric Company
Potomac Electric Power Company
Powder River Energy Corporation
PPL Electric Utilities
Prairie du Sac Utilities
Progress Energy Carolinas, Inc.
Provo City Corporation
Public Service Co. of New Mexico
Public Service Company of New Hampshire
Public Service Electric & Gas Company
Public Service Oklahoma (PSO)
Public Utility District No. 1 of Chelan County
Rappahannock Electric Cooperative
Red River Valley Rural Electric Association
Reedsburg Utility Commission
River Falls Municipal Utilities
Riverside Public Utilities
Rochelle Municipal Utilities
Rochester Gas and Electric Corporation
Rochester Public Utilities
Rutherford Electric Membership Corporation
Sacramento Municipal Utility District
Salt River Project (SRP)
San Diego Gas & Electric Company
San Luis Valley REC
San Patricio Electric Cooperative, Inc.
Sawnee EMC
SCE&G
Seattle City Light
Shawano Municipal Utilities
Singing River Electric Power Association
Slinger Utilities
Snohomish county PUD
South Carolina Public Service Authority
South Central Indiana REMC
South River Electric Membership Corporation
SouthEastern Illinois Electric Cooperative, Inc.
Southern California Edison Company
Southwest Louisiana Electric Membership Corp
Southwestern Electric Cooperative, Inc.
Southwestern Electric Power Company (SWEPCO)
Spanish Fork City Corporation
Spooner City of
Springer Electric Cooperative, Inc.
Steuben Rural Electric Cooperative, Inc
Stoughton Utilities
Sturgeon Bay Utilities
Sulphur Springs Valley Electric Cooperative Inc
Sumter Electric Cooperative, Inc. (FL)
Sun Prairie Water & Light
Tampa Electric Company
Tucson Electric Power (TEP)
The Caney Valley Electric Coop Association, Inc.
The Toledo Edison Co
Tillamook People's Utility District
Town of Smithfield
Traverse City Light & Power
Trico Electric Cooperative, Inc.
Tri-County Electric Cooperative, Inc.
Two Rivers Water & Light
UGI Utilities, Inc.
Umatilla Electric Cooperative
Union County Electric Cooperative, Inc.
Union Electric Company
United Cooperative Services, Inc.
United Illuminating
Unitil Energy Systems, Inc.
Upper Peninsula Power Company
Utilities Commission, City of New Smyrna Beach, Fl
Vermont Marble Power Division of Omya Inc.
Village of Morrisville Water and Light Department
Village of Winnetka
Virginia Electric & Power Co
Walton EMC
Waterloo Utilities
Waunakee Utilities
Waupun Utilities
Westby Utilities
Western Cooperative Electric Association, Inc.
Western Massachusetts Electric Company
Wheatland Electric Cooperative
Wheeling Power Company (WPCo)
Whitehall Electric Utility
Whitewater Valley REMC
Wisconsin Electric Power Company
Wisconsin Power & Light Co.
Wisconsin Public Service Corporation
Woodbury County Rural ECA
Yazoo Valley EPA

Appendix G: Data and Sources for Figures

Appendix G references graphs and figures from the chapters of the 2008 FERC Demand Response Report. This appendix provides the actual numerical data as well as the sources for such data, affording readers a better statistical view of the 2008 FERC Survey results.

Chapter II

Figure II-1. United States 2008 penetration of advanced metering

Year	Advanced Metering	Non-Advanced Metering
2008	4.7%	95.3%

Source: 2006 FERC Survey and 2008 FERC Survey

Figure II-2. Penetration of advanced metering by type of entity

Ownership	2006 Survey	2008 Survey
Cooperatives	3.8%	16.4%
Municipal Entities	0.3%	4.9%
Investor-Owned Utility	0.2%	2.7%
Public Utility District	0.1%	2.2%
Federal and State	0.2%	1.1%
Overall Average	0.7%	4.7%

Source: 2006 FERC Survey and 2008 FERC Survey

Figure II-3. AMI penetration by region

Region	2006 Survey	2008 Survey
FRCC	0.1%	10.4%
ERCOT	0.7%	9.0%
SPP	3.0%	5.8%
SERC	1.2%	5.8%
RFC	0.4%	5.1%
MRO	0.6%	3.7%
WECC	0.5%	2.1%
Hawaii	0.0%	1.6%
NPCC	0.1%	0.3%
ASCC	0.0%	0.0%
Overall Average	0.7%	4.7%

Source: 2006 FERC Survey and 2008 FERC Survey

Figure II-4. Reported uses of advanced metering in 2006 and 2008

Use of AMI	2006 Survey	2008 Survey
Home area network		0.9%
Pricing/event notification	14.0%	4.1%
Pre-pay	0.4%	4.6%
Interface with gas or water meters	5.5%	6.9%
Price responsive demand response	25.4%	11.1%
Remotely upgrade firmware		13.8%
Remotely change metering parameters	24.2%	20.3%
Load forecasting	41.9%	29.0%
Outage mapping		32.3%
Asset management	22.0%	34.6%
Power Quality	33.9%	47.0%
Remote connect/disconnect	15.3%	47.9%
Outage restoration		48.8%
Theft detection and other line losses	41.1%	58.5%
Outage detection	32.2%	61.8%
Enhanced customer service	67.8%	66.8%

Source: 2006 FERC Survey and 2008 FERC Survey

Chapter III

Figure III-1. Number of customers enrolled in direct load control programs by region and type of entity

Region	Cooperative Entities	Federal and State	Investor-Owned Utilities	Municipal Entities	Total
ERCOT	1,582			68,581	70,163
FRCC	19,328		1,190,798	0	1,210,126
MRO	328,879		493,084	36,901	858,864
NPCC	13,095	0	55,022	6,076	74,193
RFC	118,171		1,207,821	32	1,326,024
SERC	354,472	0	482,564	20,956	857,992
SPP	31,330	0	14,405	400	46,135
WECC	6,326	0	515,228	133,308	654,862
Other			28,525		28,525
Total	873,183	0	3,987,447	266,254	5,126,884

Source: 2008 FERC Survey

Figure III-2. Number of entities reporting interruptible/curtailable rates by region and type of entity

Region	Cooperative Entities	Federal and State	Investor-Owned Utilities	Municipal Entities	Total
ERCOT	1	0	0	1	2
FRCC	3	0	2	3	8
MRO	34	0	14	15	63
NPCC	1	1	10	18	30
RFC	16	0	26	5	47
SERC	37	2	7	4	50
SPP	20	0	5	4	29
WECC	3	0	7	3	13
Other	1	0	5	0	6
Total	116	3	76	53	248

Source: 2008 FERC Survey

Figure III-3. Number of entities reporting capacity, demand bidding, & emergency programs by region in 2006 and 2008

2008				
Region	**Capacity Programs**	**Demand Bidding**	**Emergency**	**Total**
ERCOT	7	1	5	13
FRCC	0	0	1	1
MRO	12	14	24	50
NPCC	26	13	32	71
RFC	14	11	31	56
SERC	6	6	19	31
SPP	5	3	9	17
WECC	10	9	13	32
Other	1	0	2	3
Total	81	57	136	274

2006				
Region	**Capacity Programs**	**Demand Bidding**	**Emergency**	**Total**
ERCOT	1	1	0	2
FRCC	0	0	1	1
MRO	5	6	10	21
NPCC	15	6	25	46
RFC	7	7	10	24
SERC	0	3	3	6
SPP	2	0	1	3
WECC	7	7	8	22
Other	0	0	1	1
Total	37	30	59	126

Source: 2006 FERC Survey and 2008 FERC Survey

Figure III-4. Number of entities reporting residential time-of-use rates by region and type of entity

Region	Cooperative Entities	Federal and State	Investor-Owned Utilities	Municipal Entities	Total
ERCOT	2	-	-	1	3
FRCC	0	-	5	3	8
MRO	19	-	16	30	65
NPCC	1	0	20	2	23
RFC	12	-	42	1	55
SERC	15	3	16	1	35
SPP	2	0	2	0	4
WECC	22	0	16	9	47
Total	73	3	118	47	241

Source: 2008 FERC Survey

Figure III-5. Number of customers reported as enrolled in time-of-use rate programs by region and type of entity

Region	Cooperative Entities	Federal and State	Investor-Owned Utilities	Municipal Entities	Total
ERCOT	1			13,217	13,218
FRCC	0		9,288	2	9,290
MRO	20,273		42,605	273	63,151
NPCC	6	0	212,935	45	212,986
RFC	797		252,777	6	253,580
SERC	7,362	9,894	41,450	149	58,855
SPP	3,136	0	1,399	0	4,535
WECC	9,326	0	454,370	203,238	666,934
Total	40,901	9,894	1,014,824	216,930	1,282,549

Source: 2008 FERC Survey

Figure III-6. Number of entities reporting retail real-time pricing by region & type of entity

Region	Cooperative Entities	Federal and State	Investor-Owned Utilities	Municipal Entities	Total
ERCOT	2	-	-	-	2
FRCC	-	-	2	-	2
MRO	5	-	4	3	12
NPCC	1	1	9	4	15
RFC	3	-	18	-	21
SERC	2	1	10	5	18
SPP	5	-	2	-	7
WECC	2	1	2	3	8
Other	-	-	-	-	-
Total	20	3	47	15	85

Source: 2008 FERC Survey

Figure III-7. Potential peak load reduction by customer class in 2006 and 2008 (MW)

	Residential	Commercial	Industrial	Other	Wholesale	Total
2006 Survey	5,803	4,802	9,560	589	8,899	29,653
2008 Survey	6,056	4,119	13,315	1189.551	12,656	37,335

Source: 2006 FERC Survey and 2008 FERC Survey

Figure III-8. Reported potential peak load reduction by region and customer class (MW)

Region	Residential	Commercial	Industrial	Transport	Other	Wholesale	Total
ERCOT	80	102	729	0	51	41	1,002
FRCC	1,644	732	613		9		2,998
MRO	908	303	2,388		74	4,176	7,848
NPCC	111	752	379	24	229	3,870	5,365
RFC	1,337	457	3,005	24	498	3,662	8,983
SERC	944	657	3,916		114	346	5,978
SPP	67	198	150	4	112	496	1,026
WECC	942	869	2,130		51	65	4,057
Other	25	49	5				78
Total	6,056	4,119	13,315	51	1,138	12,656	37,335

Source: 2008 FERC Survey

Figure III-9. Potential peak load reduction by type of program and by customer class (MW)

Type of Program	Residential	Commercial	Industrial	Other	Transportation	Wholesale	Total
Interruptible	13	529	7,491	0			8,033
Direct Load Control	5,448	1,198	789	399	4	3,209	11,047
Emergency Demand Response	303	427	650			3,438	4,818
Capacity		42	347			2,319	2,708
Ancillary Services		13	223			417	653
Demand Bidding		121	115			2,412	2,648
Multiple	140	910	1,680	498	48	847	4,123
Other	30	290	167	12	0	1	500
Real - Time Pricing	1	294	1,116	226			1,637
Critical Peak Pricing	21	115	32			12	180
Critical Peak Rebate		1	55				56
Time of Use	99	182	652	4			937
Total	6,055	4,122	13,317	1139	52	12,655	37,340

Source: 2008 FERC Survey

Figure III-10. Potential and actual 2007 peak load reduction by demand response resources, by region (MW)

Region	Potential Peak Reduction	Actual Peak Reduction	Total
ERCOT	1,002	353	3,127
FRCC	2,998	1,269	4,267
MRO	7,848	3,130	11,434
NPCC	5,365	986	6,452
RFC	8,983	3,678	13,365
SERC	5,978	2,243	8,442
SPP	1,026	489	1,868
WECC	4,057	1,222	5,278
Other	78	29	107
Total	37,335	13,398	54,341

Source: 2008 FERC Survey

Figure III-11. Estimated potential peak load reduction by demand response resources by region and customer class (MW)

Region	Residential	Commercial	Industrial	Other	Wholesale	Total
ERCOT	80	102	729	51	1813	2774
FRCC	1644	732	613	9		2998
MRO	908	303	2815	74	4205	8305
NPCC	111	852	379	253	3871	5466
Other	25	49	5			78
RFC	1337	608	3709	522	3512	9688
SERC	944	657	4116	114	367	6199
SPP	67	198	306	195	613	1379
WECC	942	869	2130	51	65	4057
Total	6056	4370	14802	1270	14446	40943

Source: 2008 FERC Survey

Figure III-12. Potential peak load reduction by type of entity and customer class (MW)

Ownership	Residential	Commercial	Industrial	Other	Wholesale	Total
Investor-Owned Utility	4,412	3,297	12,005	437	115	20,266
Cooperative Entities	1,342	558	688	356	4,421	7,365
Municipal Entities	299	215	915	32	850	2,311
Retail/Power Mark.	0	135	541	420	0	1,096
Federal and State	3	165	653	24	0	845
ISO/RTO	0	0	0	0	9,060	9,060
Total	6,056	4,370	14,802	1,269	14,446	40,943

Source: 2006 FERC Survey and 2008 FERC Survey

FEDERAL ENERGY REGULATORY COMMISSION

ASSESSMENT OF

Demand Response & Advanced Metering

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