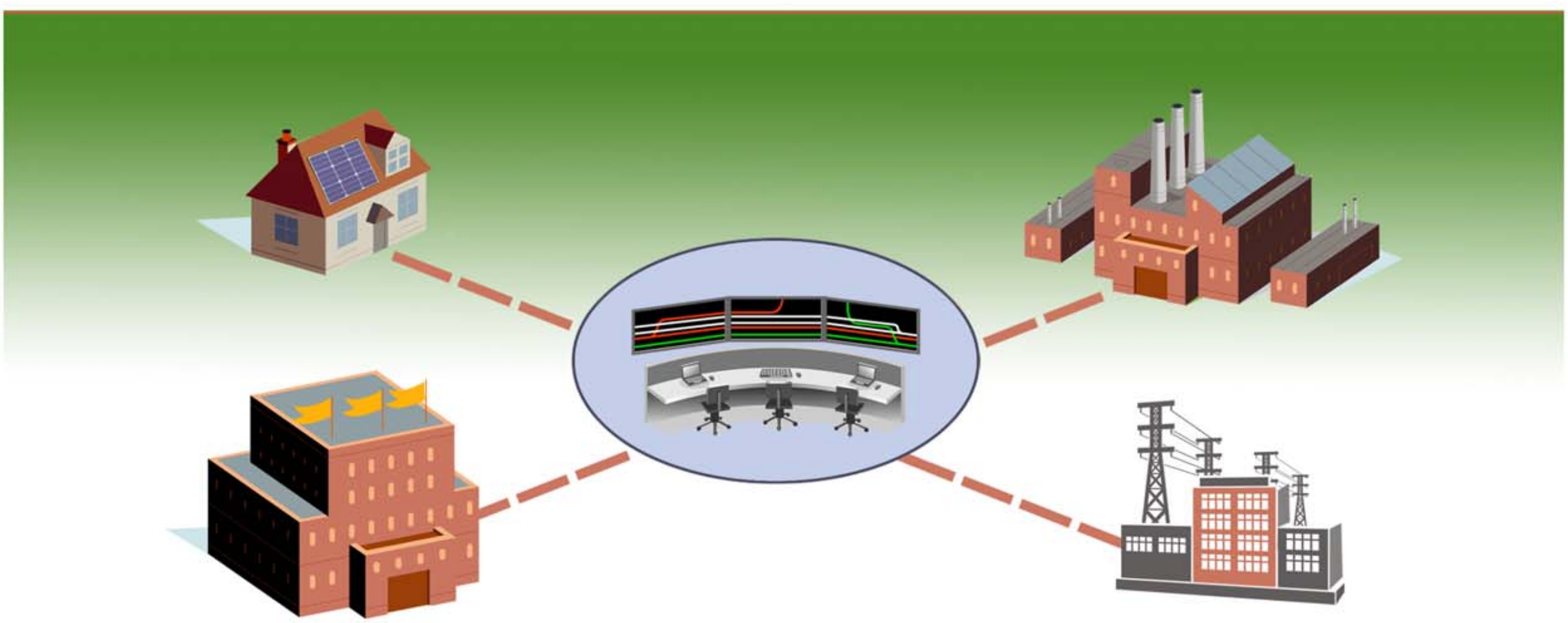
ASSESSMENT OF

Demand Response & Advanced Metering

STAFF REPORT



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Staff Report

Federal Energy Regulatory Commission

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EXECUTIVE SUMMARY

In the past year, significant progress has been achieved for both wholesale and retail electricity demand response and advanced metering, supported by the actions of state regulators, federal regulators and federal funding under the American Recovery and Reinvestment Act, the development of interoperability standards, and efforts of industry and customers. According to information provided by survey respondents to the Federal Energy Regulatory Commission (FERC) 2012 Demand Response and Advanced Metering Survey, the potential demand response resource contribution from all U.S. demand response programs is estimated to be nearly 72,000 megawatts (MW), or about 9.2 percent of U.S. peak demand. This is an increase of about 13,000 MW from the 2010 FERC Survey. The regions with the largest estimated demand response capability are the Midwest-to-Mid-Atlantic region, the Southeast, and the Upper Midwest. With regard to advanced metering, penetration reached approximately 22.9 percent in 2011 in the United States, compared to approximately 8.7 percent in the 2010 FERC Survey (covering calendar year 2009). Florida, Texas, and the West have advanced meter penetrations exceeding 30 percent. As in previous surveys, electric cooperatives have the largest penetration, nearly 31 percent, among categories of organizations.

More than 1,900 entities responded to the voluntary FERC survey and many made themselves available for follow-up questions. FERC staff greatly appreciates the responses and assistance in completing the information for this Report.

CHAPTER 1. INTRODUCTION

The Energy Policy Act of 2005 (EPAct 2005) requires the FERC to prepare and publish an annual report on the penetration of advanced metering and demand response programs in the electric power industry in the United States. This data is to be divided and presented by region, and the information is to cover all types of electric consumers.

EPAct 2005 expressly requires that the Commission's annual report 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.

This Report is the fourth annual comprehensive report based on a first-of-its-kind survey of demand response and advanced metering. The first report was published in August 2006, *Assessment of Demand Response and Advanced Metering*.[1] Since 2006, Commission staff has published a series of annual reports assessing demand response and advanced metering in the U.S. In support of these reports, the FERC staff has conducted comprehensive nationwide surveys every other year. In intervening years reports consist of updates based on publicly-available information and discussions with market participants and industry experts. Commission staff published its most recent annual report in November 2011.[2]

Preparation of This Year's Report

In preparing this report, Commission staff undertook several activities, the most significant being the preparation and release of the Demand Response and Advanced Metering Survey (2012 FERC Survey). Commission staff also reviewed relevant literature and recent developments on advanced metering, demand response programs, and time-based rates. As with past surveys, the 2012 FERC Survey gathers data for the previous calendar year, 2011.

[1] 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/dem-res-adv-metering.asp.

[2] FERC, *Assessment of Demand Response & Advanced Metering: Staff Report*, November 2011. The annual reports are available at http://www.ferc.gov/industries/electric/indus-act/demand-response/dem-res-adv-metering.asp.

Demand Response and Advanced Metering Survey

The 2012 FERC Survey was conducted in the spring months of 2012 and requested information from 3,349 entities in all 50 states,[3] representing all aspects of the electricity delivery industry: investor-owned utilities, municipal utilities, rural electric cooperatives, power marketers, state and federal agencies, and other demand response providers.[4] The survey sought the following: (a) general information about the entity responding to the survey, including contact information, customer size, and electricity demand and consumption; (b) the number of advanced meters and their use; (c) existing demand response and time-based rate programs, including their current level of resource contribution; and (d) plans for future demand response program offerings. Like the 2010 Survey, the 2012 FERC Survey combined advanced metering and demand response questions into one survey form. The FERC staff also made efforts to enhance the clarity of instructions and definitions for the 2012 FERC Survey.

More than 1,978 entities responded to the 2012 FERC Survey, representing a response rate of over 59 percent. This is an increase from the 2010 FERC Survey response rate of 52 percent.

Information gathered through the 2012 FERC Survey serves as the basis for this report's estimates of the market penetration[5] of advanced metering, demand response resource contributions, and current demand response and time-based rate programs. This report also utilizes results from the 2010, 2008 and 2006 FERC Surveys to assess trends in advanced metering deployment and demand response in the U.S.

Report Organization

The **Introduction (Chapter 1)** of this report describes the report's structure, along with a brief overview of the 2012 Survey methodology and key findings. The following chapters provide the information required by EPAct 2005 section 1252(e)(3).

Advanced Metering Infrastructure (Chapter 2) presents 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. The chapter concludes with a description of major challenges and issues for advanced metering in the U.S.

Demand Response (Chapter 3) presents survey results on demand response programs (including time-based rate programs), and provides the regional and national distribution of these programs. The chapter also includes estimates of the overall size of demand response resources in the U.S. Chapter 3 then reviews demand response trends and developments at the national and state level, and identifies several key trends in demand response. This chapter also reviews Commission demand response activities and steps that have been taken to ensure comparable treatment of demand response in regional transmission planning.

[3] Later in the process it was determined that 15 of these entities were either out of business or not in a relevant business.

[4] **Appendices D** and **H** include detailed information on the survey and sample design. **Appendix E** lists the respondents to the survey.

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

Finally, Chapter 3 concludes with a summary of potential barriers to demand response, as identified by various sources.

Smart Grid Standards Development (Chapter 4) is a new section in this report series, and provides an overview of work underway to develop and implement smart grid interoperability standards that help support demand response.

This report also includes eight appendices that provide reference material and additional detail on the survey data and responses. **Appendix A** provides 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 2012 survey. **Appendix D** provides additional detail on the 2012 FERC Survey and survey response rates. **Appendix E** lists the entities who responded to the 2012 FERC Survey. **Appendix F** lists the entities that reported operating demand response programs in the 2012 survey. **Appendix G** provides data tables associated with each of the figures in this report. **Appendix H** describes the estimation methods used in this report.

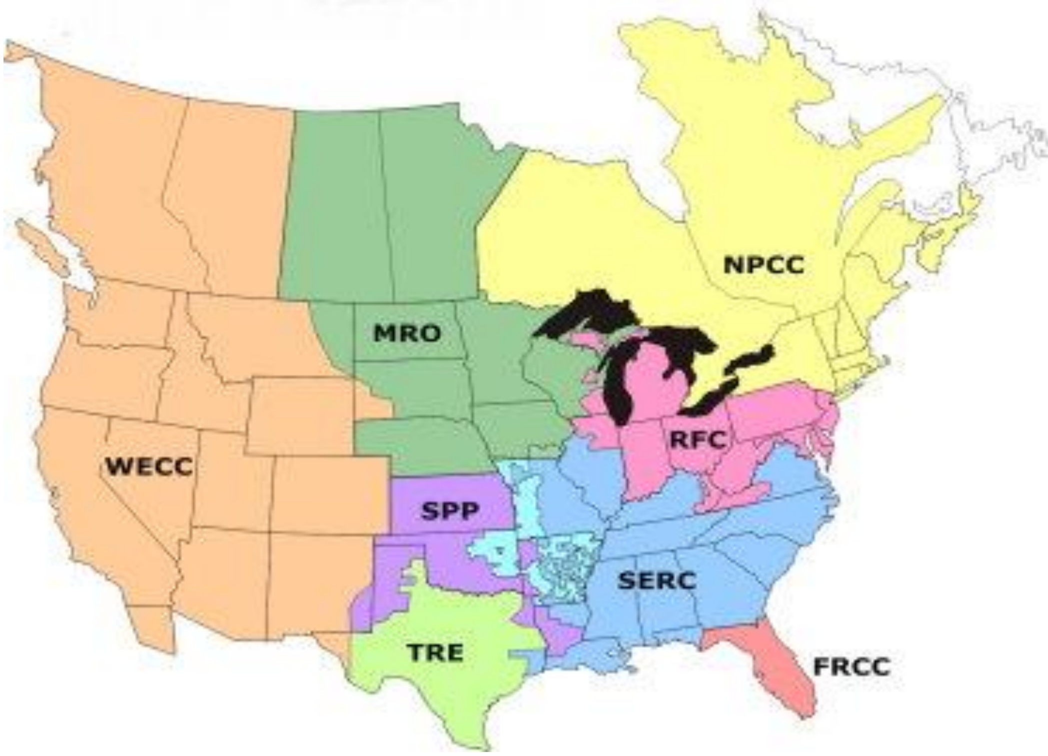
Regions in This Report

As in past reports, Staff is presenting the results of the 2012 Survey by NERC region. NERC (North American Electric Reliability Council) is an international nonprofit organization certified by the FERC as the electric reliability organization for the U.S. The 2012 FERC Survey uses NERC's eight regional divisions to better identify trends and align regulatory and industry geographical units. The regional entities are:

- Florida Reliability Coordinating Council (FRCC)
- Midwest Reliability Organization (MRO)
- Northeast Power Coordinating Council (NPCC)
- Reliability*First* Corporation (RFC)
- SERC Reliability Corporation (SERC)
- Southwest Power Pool (SPP)
- Texas Reliability Entity (TRE)
- Western Electricity Coordinating Council (WECC)

The map in Figure 1.1 illustrates the boundaries of the NERC regions. Although some NERC regions include areas in Canada and Mexico, the Commission only requested data from the U.S. portions of these NERC regions. In this report, Hawaii and Alaska are not included in most regional data summaries, but are included in state-level data tables.

Figure 1-1. NERC regions.



FRCC - Florida Reliability Coordinating Council
MRO - Midwest Reliability Organization
NPCC - Northeast Power Coordinating Council
RFC - Reliability*First* Corporation
SERC - SERC Reliability Corporation
SPP - Southwest Power Pool
TRE - Texas Reliability Entity
WECC - Western Electricity Coordinating Council

Source: North American Electric Reliability Corporation, July 2012.

CHAPTER 2. ADVANCED METERING INFRASTRUCTURE

This chapter reports on the first topic in EPAct 2005 section 1252(e)(3):

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

The information presented is divided into the following three sections and is based on the 2012 FERC Survey, with comparisons to previous FERC Surveys (as appropriate) to demonstrate trends in advanced metering deployment on a regional basis, by type of entity, and by customer type.[6]

- Definition of Advanced Metering
- Advanced Metering Penetration
- Developments and Issues in Advanced Metering

All figures and tables are labeled "Estimated…" This indicates that additional information was used in conjunction with 2012 FERC Survey data to improve the accuracy of Staff's estimates. A detailed description of these estimation methods can be found in **Appendix H**.

Definition of Advanced Metering

For the 2012 FERC Survey, FERC staff used the following definition of advanced meters:

> **Advanced Meters**: Meters that measure and record usage data at hourly intervals or more frequently, and provide usage data to both consumers and energy companies at least once daily. Data are used for billing and other purposes. Advanced meters include basic hourly interval meters, meters with one-way communication, and real-time meters with built-in two-way communication capable of recording and transmitting instantaneous data.

Several respondents to the 2012 FERC Survey provided lower advanced meter counts than in previous FERC Surveys. Respondents that reported large declines were contacted for explanation. During these calls, staff learned anecdotally that many of the reported declines were due to respondents reclassifying their responses based on a better understanding of the survey's "advanced meter" definition. For example, many respondents had installed meters with advanced metering capability, but were still in the process of programming the software and establishing the infrastructure to allow for communication on a daily basis. Consequently, these installed meters did not meet the advanced meter definition.

[6] A full database of survey responses is available at http://www.ferc.gov/industries/electric/indus-act/demand-response/dem-res-adv-metering.asp.

Advanced Metering Penetration

This section describes the analytical approach used in the 2012 FERC Survey and provides summary findings.

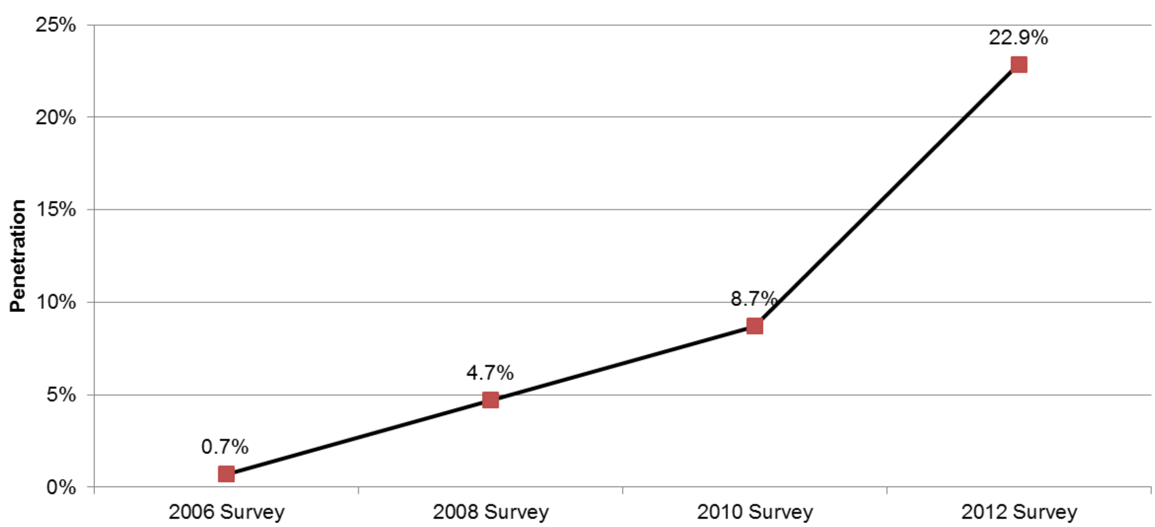
Analytical Approach

Commission Staff estimates of advanced metering penetration in the U.S. are primarily based on the 2012 FERC Survey data. However, the 2012 advanced metering data was supplemented by past FERC Survey data and survey data from the Energy Information Administration's Annual Electric Power Industry Report (i.e., Form EIA-861 survey data)[7] for this report. In contrast to previous years, the 2012 estimation methods both fill in missing data and correct for reporting errors. A detailed explanation of these estimation methods can be found in **Appendix H**.

Survey Findings

Results indicate significant growth in advanced metering deployment in the U.S. As Figure 2-1 illustrates between 2006 and 2012, the number of advanced meters currently operating in the U.S. (38 million) as a percentage of total meters installed is estimated to be 23 percent. This represents a 14 percentage point increase from 2010 levels.

Figure 2-1. Estimated advanced metering penetration nationwide reported in FERC Surveys 2006, 2008, 2010, and 2012



Secondary sources suggest that advanced metering deployment will continue to increase significantly past 2012. While as noted above the FERC Survey reports nearly 38 million advanced meters installed as of December 31, 2011, the Institute for Energy Efficiency (IEE)

[7] The Energy Information Administration collects information on advanced metering in its annual Form EIA-861 (Annual Electric Power Industry Report). As **Appendix H** describes, EIA provided FERC staff with preliminary Form EIA-861 data to help improve estimation.

projects that a total of 65 million advanced meters will be deployed by 2015.[8] In addition, recipients of U.S. Department of Energy Smart Grid Investment Grants report adding almost 1 million advanced meters over the first and second quarters of 2012.[9]

The following tables and figures in this chapter provide detailed information on the estimated 38 million advanced meters operating in the U.S. by geographic region, customer class, and ownership category. Table 2-1 below lists the respondents with the five largest increases in advanced meters from 2010 to 2012 (ranked by the size of the increase in reported advanced meters).

Table 2-1. Entities with the five largest 2010 to 2012 increases in reported advanced meters

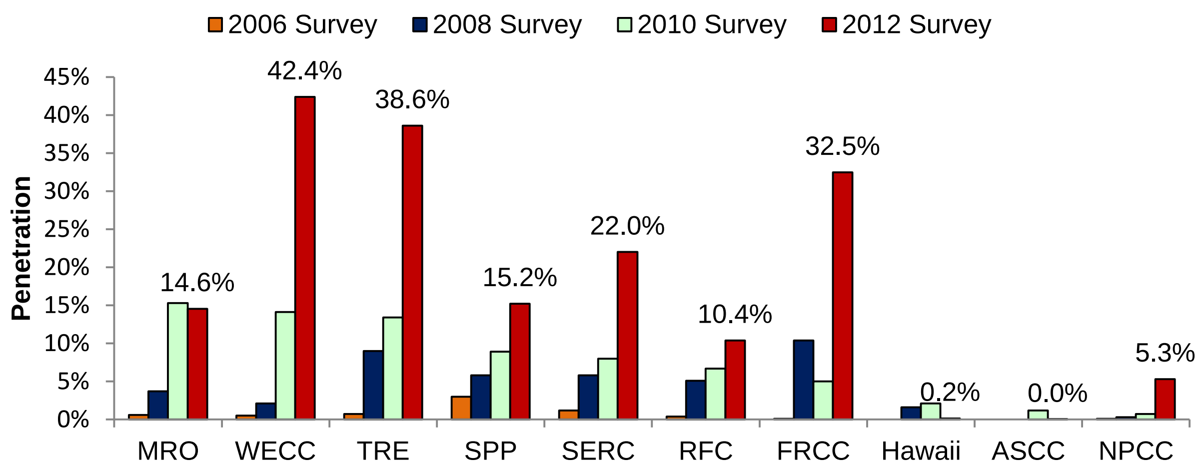
Entity Name	NERC Region	State	2010 Advanced Meters	2012 Advanced Meters	Advanced Meter Increase	Advanced Metering Penetration
Southern California Edison	WECC	CA	147,645	3,740,640	3,592,995	75.2%
Florida Power & Light Company	FRCC	FL	202,510	2,675,479	2,472,969	58.8%
Pacific Gas and Electric Company	WECC	CA	2,085,712	4,508,036	2,422,324	88.7%
Oncor Electric Delivery Company	TRE	TX	662,774	2,664,462	2,001,688	83.5%
Puget Sound Energy, Inc.	WECC	WA	7,432	1,900,306	1,892,874	99.9%

The advanced metering deployments shown in Table 2-1 are currently in the middle to late stages of deployment. The funding for these advanced metering deployments were primarily subject to state commission-approved cost recovery. For example, the California Public Utility Commission authorized two of the state's primary investor-owned utilities, Southern California Edison and Pacific Gas and Electric, to replace conventional meters with advanced meters.[10] Southern California Edison expects to complete its deployment of approximately 5 million advanced meters by the end of 2012, and reports that this deployment was approximately 78 percent complete as of January 2012.[11] Pacific Gas and Electric reports installing nearly 4.7 million advanced meters as of November 2011, and expects to complete its advanced meter rollout by mid-2013.[12]

[8] Institute for Electric Efficiency, *Utility-Scale Smart Meter Deployments, Plans, & Proposals*, May 2012, available at http://www.edisonfoundation.net/iee/Documents/IEE_SmartMeterRollouts_0512.pdf.
[9] SmartGrid.gov, Advanced Metering Infrastructure and Customer Systems, available at http://www.smartgrid.gov/recovery_act/deployment_status/ami_and_customer_systems.
[10] California Public Utilities Commission, The Benefits of Smart Meters, available at http://www.cpuc.ca.gov/PUC/energy/Demand+Response/benefits.htm.
[11] California Public Utilities Commission, California Division of Ratepayer Advocates, Case Study of Smart Meter System Deployment: Recommendations for Ensuring Ratepayer Benefits, March 2012, available at http://www.dra.ca.gov/uploadedFiles/Content/Energy/Management_and_Conservation/Smart_Meters/SmartMeterSystemDeploymentReportMar2012FinalDraft_wcover_Public.pdf.
[12] PG&E, SmartMeter™ Program Data, 12/13/2011, available at http://www.pge.com/includes/docs/pdfs/myhome/customerservice/meter/smartmeter/SmartMeterProgramData_12-13-11.pdf.

Figure 2-2 illustrates how advanced metering penetration has increased in nearly every region in the continental U.S. between 2010 and 2012.[13] In 2010, no NERC region had an advanced metering penetration rate over 20 percent; by contrast, Staff estimates that three regions (FRCC, TRE and WECC) now have an advanced metering penetration rate over 30 percent. WECC has the highest advanced metering penetration rate of over 40 percent. This is primarily driven by investor-owned utility rollouts in California, Oregon, Nevada, Idaho, and Arizona.

Figure 2-2. Estimated advanced metering penetration nationwide in 2006, 2008, 2010 and 2012 FERC Surveys



	MRO	WECC	TRE	SPP	SERC	RFC	FRCC	Hawaii	ASCC	NPCC
2006 Survey	0.6%	0.5%	0.7%	3.0%	1.2%	0.4%	0.1%	0.0%	0.0%	0.1%
2008 Survey	3.7%	2.1%	9.0%	5.8%	5.8%	5.1%	10.4%	1.6%	0.0%	0.3%
2010 Survey	15.3%	14.1%	13.4%	8.9%	8.0%	6.7%	5.0%	2.1%	1.2%	0.7%
2012 Survey	14.6%	42.4%	38.6%	15.2%	22.0%	10.4%	32.5%	0.2%	0.0%	5.3%

Table 2-2 compares the estimated penetration of advanced meters by customer class across the 2008, 2010 and 2012 FERC Surveys. The increases in advanced metering penetration are generally driven by the residential sector. However, advanced metering penetration for nonresidential customers has also increased significantly in some regions, most notably WECC and TRE, where advanced metering penetration is estimated to be over 30 percent.

[13] A notable departure from the trend of increasing advanced metering penetration between the 2010 and 2012 Surveys is for the MRO region, where there was an apparent slight decrease in advanced metering penetration as compared to the 2010 FERC Survey estimate. Small decreases in penetration appeared in Hawaii and ASCC as well. In the MRO region, Wisconsin Public Service reported a decline in 375,000 advanced meters between survey years. Follow-up conversations revealed that in the 2010 FERC Survey Wisconsin Public Service had mistakenly reported automated meter reading (AMR) meters as advanced meters, and corrected for this in 2012. Most of the decline in Hawaii was due to suspected AMR entries as well, discovered through comparison analysis with the 2011 EIA-861 Survey preliminary database. In ASCC, no 2012 responses reporting advanced meters were received, but a small number of advanced meters were estimated for one entity in ASCC in 2010.

Table 2-2. Estimated advanced metering penetration by region and customer class

	Advanced Metering Penetration								
	All Classes			Residential Class			Nonresidential Classes		
FERC Survey Region	2008	2010	2012	2008	2010	2012	2008	2010	2012
MRO	3.7%	15.3%	14.6%	4.0%	15.8%	15.3%	2.2%	11.9%	8.9%
WECC	2.1%	14.1%	42.4%	2.1%	14.9%	43.5%	2.0%	9.1%	33.5%
TRE	9.0%	13.4%	38.6%	8.5%	13.4%	39.0%	12.4%	13.1%	34.1%
SPP	5.8%	8.9%	15.2%	6.1%	9.2%	15.9%	4.2%	7.5%	11.6%
SERC	5.8%	8.0%	22.0%	6.1%	8.3%	24.6%	3.2%	5.9%	5.6%
RFC	5.1%	6.7%	10.4%	5.0%	6.7%	10.9%	6.1%	6.9%	6.2%
FRCC	10.4%	5.0%	32.5%	10.8%	5.2%	34.5%	7.8%	3.3%	17.1%
Hawaii	1.6%	2.1%	0.2%	1.6%	2.2%	0.1%	1.6%	1.8%	0.4%
ASCC	0.0%	1.2%	0.0%	0.0%	1.3%	0.0%	0.0%	0.6%	0.0%
NPCC	0.3%	0.7%	5.3%	0.3%	0.6%	5.3%	1.0%	1.1%	6.0%
United States	4.7%	8.7%	22.9%	4.7%	8.9%	23.9%	4.2%	7.0%	14.4%

Table 2-3 lists estimated market penetration rates of advanced meters by state. The largest increase in advanced metering market penetration was in the District of Columbia; penetration in D.C. is estimated to increase from nearly zero percent in the 2010 survey to over 80 percent in the 2012 survey.[14] This can be attributed to the Potomac Electric Power Company (Pepco) advanced metering rollout that began in 2011.[15]

California has the second-highest market penetration rate in the country, 70 percent. This is primarily due to advanced metering rollouts by two utilities: Southern California Edison and Pacific Gas and Electric.[16] There were also large advanced metering deployments in other Western states such as in Oregon, Nevada, Idaho, and Arizona. Each of these states has a market penetration rate over 50 percent and contains at least one investor-owned utility that deployed over 200,000 advanced meters between 2010 and 2012.[17]

Georgia's advanced metering market penetration rate increased by almost 54 percentage points from 2010 to 2012. The majority of this growth came from Cooperatives such as the Central Georgia Electric Membership Corp., which added over 140,000 advanced meters between 2010 and 2012.

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[14] As noted in the 2010 *Assessment of Demand Response & Advanced Metering: Staff Report*, the large apparent decrease in advanced meter count and total meter count for the District of Columbia from 2008 to 2010 was due to a correction in reporting that erroneously included Pepco's meters in the Maryland suburbs in the District of Columbia estimate.

[15] In July 2011, Pepco began a smart-meter rollout that was expected to include over 500,000 customers by the end of 2012, and complete their D.C. deployment by the end of 2011. Pepco smart-meter rollout announcement is available at http://www.pepco.com/welcome/news/releases/archives/2011/article.aspx?cid=1787.

[16] As highlighted in Table 2-1, Southern California Edison and Pacific Gas & Electric (both located in California) were the first and third largest entities adding AMI meters in the country, respectively. Pacific Gas & Electric is focused on installing advanced meters for all their customers by 2013, with over 9 million already installed. See http://www.pge.com/myhome/customerservice/smartmeter/installation/.

[17] Arizona Public Service in Arizona, Idaho Power Company in Idaho, Nevada Power Company in Nevada, and Portland General Electric Company in Oregon.

Table 2-3. Estimated penetration of advanced metering by state in 2008 – 2012[18]

	2008			2010			2012		
State	AMI meters	Total meters	Penetration	AMI meters	Total meters	Penetration	AMI meters	Total meters	Penetration
DC	1,348	809,412	0.2%	2	275,554	0.0%	248,133	285,046	87.1%
CA	170,896	14,595,958	1.2%	2,475,896	14,837,434	16.7%	10,459,477	14,836,734	70.5%
ID	105,933	769,963	13.8%	198,370	803,576	24.7%	530,655	802,440	66.1%
GA	342,772	4,537,717	7.6%	514,403	4,401,623	11.7%	3,013,541	4,599,392	65.5%
AZ	96,727	2,810,224	3.4%	847,177	2,915,712	29.1%	1,646,410	2,977,092	55.3%
NV	10,835	1,292,331	0.8%	24,378	1,255,950	1.9%	717,220	1,299,632	55.2%
AL	139,972	2,774,764	5.0%	127,092	2,467,741	5.2%	1,397,672	2,604,431	53.7%
DE	0	438,020	0.0%	10,433	455,926	2.3%	310,890	593,583	52.4%
OR	39,797	1,890,423	2.1%	478,897	1,896,717	25.2%	960,151	1,874,339	51.2%
ME	426	780,748	0.1%	20,315	796,691	2.5%	671,036	1,372,735	48.9%
TX	868,204	10,870,895	8.0%	1,284,179	11,013,153	11.7%	5,948,975	16,987,336	35.0%
OK	161,795	1,875,325	8.6%	215,462	2,028,522	10.6%	703,091	2,071,552	33.9%
FL	765,406	9,591,363	8.0%	490,150	9,644,617	5.1%	3,052,570	9,771,192	31.2%
SD	41,191	475,477	8.7%	41,122	432,632	9.5%	109,586	440,774	24.9%
WY	12,268	318,282	3.9%	14,437	303,272	4.8%	70,650	308,024	22.9%
PA	1,443,285	6,036,064	23.9%	1,493,201	6,152,994	24.3%	1,623,982	7,753,238	20.9%
TN	60,385	3,160,551	1.9%	252,341	2,761,758	9.1%	724,469	3,738,153	19.4%
WI	117,577	3,039,830	3.9%	757,688	3,418,498	22.2%	562,861	3,107,700	18.1%
MI	73,948	5,311,570	1.4%	269,933	4,865,396	5.5%	738,702	4,859,675	15.2%
ND	33,336	375,473	8.9%	42,875	445,164	9.6%	61,329	407,033	15.1%
NC	143,093	4,771,479	3.0%	385,884	4,847,336	8.0%	644,811	4,832,250	13.3%
MS	3	1,454,275	0.0%	97,344	1,511,958	6.4%	201,877	1,584,994	12.7%
AR	168,466	1,488,124	11.3%	14,578	1,529,065	1.0%	162,181	1,559,849	10.4%
NH	260	763,683	0.0%	391	755,770	0.1%	76,864	743,454	10.3%
SC	114,619	2,373,047	4.8%	312,894	2,445,044	12.8%	246,526	2,417,863	10.2%
MO	204,498	3,098,055	6.6%	506,416	3,072,893	16.5%	299,375	3,061,397	9.8%
KY	105,460	2,161,142	4.9%	273,663	2,523,833	10.8%	313,094	3,353,259	9.3%
OH	28,042	5,544,353	0.5%	289,970	6,290,618	4.6%	638,167	7,267,087	8.8%
NE	8,630	970,774	0.9%	19,290	999,353	1.9%	83,342	977,513	8.5%
IN	61,551	3,115,205	2.0%	148,129	3,355,485	4.4%	275,821	3,342,734	8.3%
IA	46,407	1,714,774	2.7%	58,092	1,576,475	3.7%	124,975	1,623,036	7.7%
KS	61,423	1,426,832	4.3%	62,626	1,467,092	4.3%	110,628	1,452,858	7.6%
MN	37,071	2,542,113	1.5%	108,232	2,602,360	4.2%	203,717	2,709,254	7.5%
CO	39,873	2,246,184	1.8%	111,330	2,403,001	4.6%	183,658	2,446,657	7.5%
VA	6,448	3,965,584	0.2%	175478	3,663,525	4.8%	201,014	3,706,158	5.4%
CT	5,838	1,600,768	0.4%	1,967	1,625,758	0.1%	101,267	2,044,906	5.0%
MD	8	1,938,948	0.0%	4,189	2,483,628	0.2%	108,881	2,856,999	3.8%
MT	8,979	549,136	1.6%	27,470	577,745	4.8%	20,101	563,920	3.6%
IL	112,410	5,701,533	2.0%	286,568	6,099,158	4.7%	196,150	6,138,749	3.2%
MA	3,907	3,077,679	0.1%	20,831	3,150,098	0.7%	70,729	3,384,865	2.1%
WA	69,377	2,987,355	2.3%	128,857	3,298,781	3.9%	74,252	4,009,332	1.9%
UT	37	1,056,718	0.0%	20,046	1,083,069	1.9%	18,250	1,069,087	1.7%
LA	44,103	2,186,249	2.0%	53,848	2,245,066	2.4%	37,691	2,325,796	1.6%
NM	20,776	904,861	2.3%	54,250	1,015,058	5.3%	68,975	4,533,949	1.5%
AK	18	315,419	0.0%	3,835	316,289	1.2%	4,045	295,821	1.4%
NY	12,778	7,811,335	0.2%	28,664	9,313,776	0.3%	23,756	9,063,297	0.3%
NJ	9,866	3,900,716	0.3%	25,744	3,953,683	0.7%	13,768	6,062,487	0.2%
HI	6,550	405,228	1.6%	8,713	411,232	2.1%	737	484,479	0.2%
RI	148	480,135	0.0%	2,381	506,379	0.5%	210	477,183	0.0%
VT	20,755	375,202	5.5%	31,293	379,139	8.3%	128	398,300	0.0%
WV	10	1,183,513	0.0%	7,039	1,033,802	0.7%	280	1,051,585	0.0%

Several advanced metering rollouts occurred in tandem with new time-of-use demand response programs. For example, Oklahoma added over 450,000 advanced meters between the 2010 and 2012 FERC Surveys, largely from the advanced metering deployments by the

[18] As noted elsewhere in this Report, entities revised what meters they included as being consistent with the definition of AMI used for this report.

Oklahoma Gas and Electric (OG&E). OG&E has stated that it is interested in delaying the need for constructing additional generation facilities until 2020; therefore, OG&E is working to combine smart grid technology (including advanced meters) with dynamic pricing to help manage demand and achieve this goal.[19] OG&E is using a combination of state and federal funding to complete this dual advanced metering/demand response program.[20]

Figure 2-3 provides the estimated national penetration rate of advanced metering by entity type. Advanced metering penetration increased for each entity type between 2010 and 2012. Cooperatives still had the highest penetration with 31 percent. However, advanced metering penetration for other entity types, such as political subdivisions[21] and investor-owned utilities, are reaching similar levels, with 29 percent and 25 percent market penetration respectively.

The growth in the political subdivision category was driven by Salt River Project, which was responsible for over 84 percent of the total advanced meters for this entity type. Salt River Project was the recipient of federal Smart Grid Investment Grant (SGIG) funding to help double its advanced metering meter penetration rate between 2010 and 2012; the SGIG project also used time-of-day pricing to allow customers to better monitor and manage their energy consumption.[22]

Customer Accessibility of Advanced Metering Data

The 2010 and 2012 FERC Surveys asked respondents with demand response or time-based rate programs to categorize the ways in which their customers are capable of receiving detailed energy usage data: over the internet, on their bills or invoices, or via a display unit (e.g., an in-home display). Figure 2-4 illustrates that internet-based access has become the dominant medium for customers to retrieve their energy usage data. In 2010, an estimated 5.4 million customers (both residential and nonresidential) were capable of using the internet to access information on their energy use. That number increased significantly to 17.5 million customers by 2012, becoming the dominant means of accessing energy usage information.

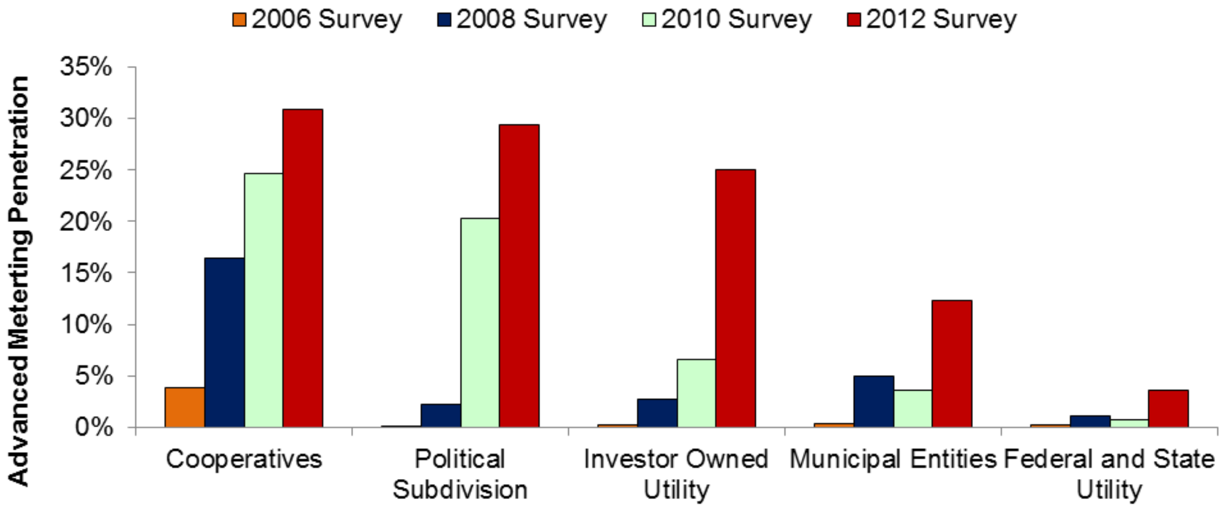
[19] Oklahoma Gas & Electric, Second Year Preliminary Results Confirm Smart Technology Helps Reduce Peak Energy Use, 1/24/2012 press release, available at http://phx.corporate-ir.net/phoenix.zhtml?c=106374&p=irol-newsArticle&ID=1652157&highlight=.

[20] *Ibid.*

[21] Political Subdivisions include public utility districts, irrigation districts, and associations like the Salt River Project.

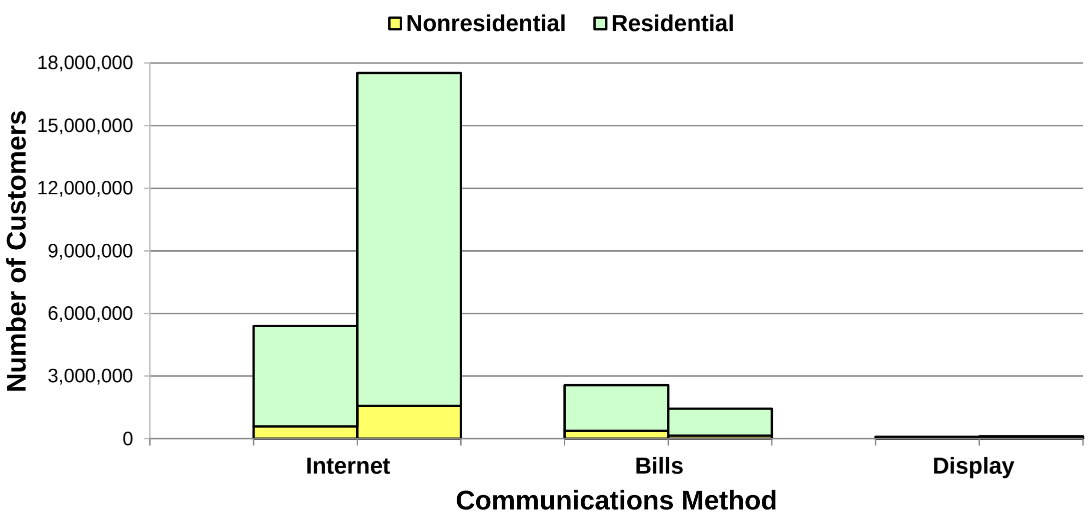
[22] Salt River Project added over 300,000 AMI meters between 2010 and 2012, and was a significant contributor to the estimated penetration of 30 percent for its entity type. Its rollout was driven by funding from U.S. Department of Energy, and its plan to install one million meters for its customers. Salt River Project smart meter information is available at http://www.srpnet.com/electric/home/millionmeters.aspx.

Figure 2-3. Estimated advanced metering penetration by type of entity in 2006, 2008 and 2010, and 2012 FERC Surveys



Ownership	Cooperatives	Political Subdivision	Investor Owned Utility	Municipal Entities	Federal and State Utility
2006 Survey	3.8%	0.1%	0.2%	0.3%	0.2%
2008 Survey	16.4%	2.2%	2.7%	4.9%	1.1%
2010 Survey	24.7%	20.3%	6.6%	3.6%	0.7%
2012 Survey	30.9%	29.4%	25.0%	12.4%	3.6%

Figure 2-4. Reported numbers of customers and communication methods for advanced metering by customer class



Developments and Issues in Advanced Metering

This section highlights developments in several key advanced metering policy areas: (1) the status of the advanced metering deployments funded by the American Recovery and Reinvestment Act (ARRA), (2) the Green Button initiative, (3) expanded customer offerings, (4) use of advanced metering data for non-billing applications, and (5) noteworthy state activities on consumer opt-out programs.

Status of the Advanced Metering Deployments Funded by the American Recovery and Reinvestment Act

The ARRA provided $4.5 billion in awards for smart grid deployment programs,[23] and a portion of that funding provided matching grants for advanced metering development. The SGIG program has funded investments in advanced meters, networks, and hardware that enable two-way communications between consumers and their electricity providers. According to U.S. Department of Energy data, it has invested $2.8 billion in advanced metering as of June 2012, and SGIG recipients have deployed and are operating 10.3 million advanced meters. A total of 15.5 million advanced meters are planned to be deployed under the ARRA program, and over two-thirds of these planned meters have been installed as of September 30, 2012.[24]

Green Button Initiative

The Green Button Initiative is an effort for utilities to voluntarily provide retail electricity customers with easily accessible and up-to-date data on their electricity usage. The initiative began in September 2011 when U.S. Chief Technology Officer Aneesh Chopra challenged the electric industry to provide customers access to their energy usage information electronically in a user-friendly format.[25] Since launching the Green Button Initiative in January 2012, 35 utilities have committed to participate,[26] which will provide 27 million households in 17 states[27] and the District of Columbia access to their energy usage information.[28] In a statement of support, the National Association of Regulatory Utility Commissioners (NARUC) stated, "Voluntary efforts like the Green Button Initiative will have a positive impact on both our electricity prices and the environment, and we salute the States and utilities that are pursuing these developments."[29]

Expanded Customer Service Offerings

Efforts to standardize the format of energy usage information and protect customer privacy[30] have fostered the rapid development of new applications to further engage and inform customers. Among these new offerings are home energy reports, customized alerts or notifications, and improved management software. Advanced metering data makes it possible for utilities and third-party service providers to offer customers these new and

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[23]U.S. Department of Energy, 2010 Smart Grid System Report, February 2012, p. 7, available at http://energy.gov/oe/downloads/2010-smart-grid-system-report-february-2012.
[24] Smartgrid.gov, Advanced Metering Infrastructure and Customer Systems, available at http://www.smartgrid.gov/recovery_act/deployment_status/ami_and_customer_systems.
[25] Aneesh Chopra, "Modeling a Green Energy Challenge after a Blue Button," Office of Science and Technology Policy, The White House, September 2011, available at http://www.whitehouse.gov/blog/2011/09/15/modeling-green-energy-challenge-after-blue-button.
[26] See http://www.whitehouse.gov/sites/default/files/microsites/ostp/energy_datapalooza_fact_sheet.pdf for more information.
[27] Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, North Carolina, Ohio, Oklahoma, Pennsylvania, Tennessee, Texas, Virginia, and West Virginia, as well as the District of Columbia.
[28] *See:* Green Button, Adopters, available at http://www.greenbuttondata.org/greenadopt.html.
[29] National Association of Regulatory Utility Commissioners, "NARUC Applauds States, Utilities for 'Green Button' Efforts," March 23, 2012 press release, available at http://www.naruc.org/News/default.cfm?pr=306.
[30] See, e.g., the NAESB Energy Service Provide Interface (see **Chapter 4**).

innovative products and services which are designed to help customers save money, qualify for incentives, and consume electricity more efficiently.

For example, the U.S. Department of Energy sponsored an "Apps for Energy" contest in April 2012 that offered $100,000 to software developers who created the best new apps to help customers utilize Green Button electricity usage data.[31] The winning application was submitted by Leafully, which created a program that compares a customer's energy usage to the number of trees needed to offset the pollution created by that electricity consumption.[32]

Other companies used social media and peer comparison/competition to promote awareness of energy consumption. For example, Opower recently partnered with Facebook and the National Resources Defense Council to launch an application that allows customers to post their electric usage data online and compare it to others with similarly-sized homes.[33]

Use of Advanced Metering Data for Non-Billing Applications

In addition to expanded service offerings, data derived from advanced metering allows utilities to help tackle long-standing issues such as outage management, power and voltage quality, overloaded customer services and overheating meter sockets. For example, advanced meters have the ability to provide "last gasp" messages. As soon as an advanced meter experiences an outage, an internal battery can provide enough power to transmit an outage message back to the utility. These messages can be actively monitored, or fed into an outage management system to determine the extent of outages and assist in dispatching the necessary resources. In addition to facilitating timely outage responses, advanced meters can reduce unnecessary service calls. For example, if a customer calls to report an outage, a call center representative can attempt to contact the customer's meter to determine immediately if the customer has power. This ability of advanced meters to detect outages proved valuable for several utilities on the East Coast during the restoration efforts following Hurricane Sandy in October 2012.[34] Many advanced meters also have the ability to sense the meter's internal temperature, related to its ability to maintain accuracy over its operating temperature range. This can be used to detect overheating conditions within the meter.

Advanced metering systems can also open up new ways of monitoring voltage throughout an electric distribution system; this can improve operational control and efficiency. Voltage typically varies across a distribution circuit, and to ensure that voltage is consistently within the allowable band (usually 114 to 126 volts), utilities have traditionally relied on engineering models to identify potential points in a circuit where voltage may fall outside the allowable range. Voltage levels outside allowable ranges can reduce customers' service quality and compromise the reliability of grid components such as transformers. However, since advanced meters provide data more frequently than traditional meters, a utility can monitor voltage levels using actual data throughout the circuit, rather than using engineering

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[31] U.S. DOE, Challenge.gov, Apps for Energy, available at http://appsforenergy.challenge.gov/.
[32] Leafully, What is Leafully?, available at https://www.leafully.com/tour/.
[33] Opower, Your electricity use vs Similar homes, available at https://social.opower.com/explore/
[34] For example, see http://www.technologyreview.com/view/506711/smart-meters-help-utility-speed-sandy-restoration/ for a description of how advanced meters helped Potomac Electric Power, and see http://www.greentechmedia.com/articles/read/a-smart-meter-in-the-superstorm for a description of how advanced metering helped Philadelphia Electric.

model estimates. Controlling voltage more precisely can also help utilities and consumers save energy; these conservation voltage reduction programs are also known as "Volt-Var."

Opt-Out Programs

Some consumers are concerned about the privacy of customer data, cybersecurity, failure rates, and overheating,[35] as well as possible adverse health effects from radio frequency emissions if the communications method uses radio frequencies. Because of these concerns, many consumer groups endorse opportunity for individual customers to forgo, or "opt-out," of advanced meter installations at their own premises.

State regulatory bodies are considering whether to permit opt-out programs, and are coming to varying conclusions. When evaluating an opt-out program, a state typically balances consumer concerns regarding advanced meters against the system cost-saving benefits of universal use in an area. Some groups argue that opt-out programs are not efficient, since having both analog and digital systems in one area could reduce a utility's ability to automate functions such as meter reading, billing, and outage detection.[36] Utilities also incur additional administrative costs to accommodate customers that opt out of advanced metering; for example, the utility might need to maintain meter reading trucks and additional staff to support the non-advanced metering customers.[37] Therefore, to maximize the potential system benefits of advanced metering, and to avoid additional administrative costs, some states have been hesitant to allow opt-out provisions in advanced metering deployment programs. For example, the Idaho Public Utilities Commission recently dismissed a consumer request to allow opting out of advanced meter installations, citing the potential costs of an opt-out program.[38]

Another issue concerning opt-out programs is how to allocate the extra cost of manually reading individual meters if some consumers choose not to use an advanced meter. The costs of an opt-out program could be allocated to (1) all rate payers in a service territory, (2) only the customers that choose to opt out, or (3) some combination of the two. For example, the Maine Public Utilities Commission[39] and the California Public Utilities Commission[40]

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[35] *See*: Maryland Public Service Commission, Notice of Opportunity to Comment, To: Service List for Case Nos. 9207, 9208, 9294, available at http://webapp.psc.state.md.us/Intranet/Casenum/caseform_new.cfm? ; Pennsylvania Public Utility Commission, Re: AMI Meter Deployment Inquiries: Commission staff August 24, 2012 data request, and PECO's September 7, 2012 responses; Gregory Karp, "ComEd confirms smart meters involved in 'small fires'" Chicago Tribune, August 2012, available at http://articles.chicagotribune.com/2012-08-30/business/chi-comed-confirms-smart-meters-involved-in-small-fires--20120830_1_smart-meters-comed-customers-poor-connection.

[36] *See:* "The Opt-Out Challenge," Electric Light & Power, March/April 2012, available at http://www.elp.com/index/current-issue/electric-light-power/volume--90/issue-02.html; Institute for Electric Efficiency, The Cost and Benefits of Smart Meters for Residential Customers, July 2011, p. 4, Available at: http://www.edisonfoundation.net/iee/Documents/IEE_BenefitsofSmartMeters_Final.pdf.

[37] *Ibid*

[38] Meters that opt-out need to be individually read by a meter reader. See Idaho Public Utilities Commission, Formal Complaint Objecting to Installation of AMI Meters, Case No. IPC-E-12- 04, Order No. 32500, available at http://www.puc.idaho.gov/internet/cases/elec/IPC/IPCE1204/ordnotc/20120327FINAL_ORDER_NO_32500.PDF.

[39] Maine Public Utilities Commission, Docket No. 2010-345, et al., Request for Commission Investigation in Pursuing the Smart Meter Initiative, et al., Order (Part I), and Order (Part II), May 19, 2011 and June 22, 2011,

recently approved opt-out programs where the costs were assigned only to customers choosing to opt out, on a tiered basis. The California and Maine programs offer differing opt-out fees under a variety of options, ranging from maintaining a traditional analog meter to simply having the wireless capabilities removed from an advanced meter.[41] Some other states do not permit utilities to charge opt-out fees. For example, Vermont enacted legislation eliminating opt-out fees in May 2012, and also required that any advanced meter already installed be removed without charge if the customer requests this option.[42]

However, to date customer participation rates in opt-out programs have been low. For example, less than one percent of Pacific Gas and Electric customers have opted out of advanced meter deployments.[43] Portland General Electric experienced an even lower opt-out rate; only 4 out of 720,000 customers chose to opt out.[44] These early advanced metering deployment results indicate that opt-out provisions support individuals' ability to make a choice, while only an insignificant number of customers have actually decided to opt out.[45]

The debate surrounding opt-out programs continues, and several states continue to assess the feasibility of implementing opt-out programs. For example, the California Public Utilities Commission began a second phase of proceedings in June 2012 to reexamine the opt-out issue and may consider extending an opt-out option to customer groups such as local governments and residents of apartment buildings/condominiums.[46] The second phase will also address the possibility that the Americans with Disabilities Act prohibits that Commission from charging opt-out fees for customers who have an analog meter for medical reasons. In addition, the Maryland Public Service Commission issued an interim order in

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available at https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/CaseMaster.aspx?CaseNumber=2010-00345.

[40] California Public Utilities Commission, Decision Modifying Decision 08-09-039 and Adopting an Opt-Out Program for Southern California Edison Company's Edison SmartConnect Program, Decision 12-04-018, Issued April 30, 2012, available at http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/165307.htm.

[41] On July 12, 2012, the Maine Law Court issued a decision that vacated the portion of Maine Public Utilities Commission's dismissal of a complaint pertaining to health and safety concerns associated with advanced meter usage in the Central Maine Power Company (CMP) service territory. The Maine PUC subsequently issued an order staying disconnection of CMP customers until the conclusion of an investigation. *See:* Maine Public Utilities Commission, Docket No. 2010-345, et al., Request for Commission Investigation in Pursuing the Smart Meter Initiative, et al., Order Staying Disconnection of CMP Customers for Failure to Pay Opt-Out Fees, August 8, 2012

[42] Vermont State Legislature, The Vermont Legislative Bill Tracking System, Senate Bill No. 214, An Act Relating to the Vermont Energy Act of 2012, Enacted May 18, 2012, available at http://www.leg.state.vt.us/database/status/summary.cfm?Bill=S.0214&Session=2012.

[43] United Telecom Council, Smart Meter Opt-Out – The Policies and Impacts, 9/27/2012 Webinar, as reported by intelligentutility, Few and fewer opting out of smart meters, September 30, 2012, available at http://www.intelligentutility.com/article/12/09/few-and-fewer-opting-out-smart-meters.

[44] *ibid*.

[45] Eric Lightner, Director of the Federal Smart Grid Task Force, DOE Office of Electricity Delivery and Energy Reliability, Roundtable 2 – Policymakers Talk, June 26, 2012.

[46] California Public Utilities Commission, Application of Pacific Gas and Electric Company for Approval of Modifications to its SmartMeter™ Program and Increased Revenue Requirements to Recover the Costs of the Modifications: Assigned Commissioner's Ruling Amending Scope of Proceeding to Add a Second Phase, Application No. 11-03-014, Enacted June 8, 2012, available at http://docs.cpuc.ca.gov/efile/RULC/168362.pdf.

May 2012 directing utilities to refrain from installing or activating advanced meters until a permanent course of action is determined.[47] Texas[48] and Nevada[49] have also been assessing the feasibility of opt-out programs.

[47]Maryland Public Service Commission, Case No. 9207: In the Matter of Potomac Electric Power Company and Delmarva Power and Light Company Request for the Deployment of Advanced Meter Infrastructure, and Case No. 9208: In the Matter of Baltimore Gas and Electric Company for Authorization to deploy a Smart Grid Initiative and to Establish a Surcharge Mechanism for the Recovery of Costs, Order No. 84926: Interim Order Regarding "Opt-out" Option for Smart Meters, May 25, 2012, available at http://webapp.psc.state.md.us/Intranet/Casenum/submit_new.cfm?DirPath=C:\Casenum\9200-9299\9207\Item_203\&CaseN=9207\Item_203.

[48] Public Utilities Commission of Texas, Project, Control No. 40190, Item 382: PUC Proceeding to Evaluate the Feasibility of Instituting a Smart Meter Opt-Out Program, available at http://interchange.puc.state.tx.us/WebApp/Interchange/application/dbapps/filings/pgControl.asp?TXT_UTILITY_TYPE=A&TXT_CNTRL_NO=40190&TXT_ITEM_MATCH=1&TXT_ITEM_NO=&TXT_N_UTILITY=&TXT_N_FILE_PARTY=&TXT_DOC_TYPE=ALL&TXT_D_FROM=&TXT_D_TO=&TXT_NEW=true.

[49] Public Utilities Commission of Nevada, Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV for approval of proposed trial Non-Standard Metering Option riders and changes to existing rules and schedules associated with implementation of the NSMO riders, Docket No. 12-05003, Filled May 2012.

CHAPTER 3. DEMAND RESPONSE

This chapter addresses the second and third topics in EPAct 2005 section 1252(e)(3):

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

This chapter presents results of the 2012 FERC Survey on demand response programs, including comparisons to previous FERC Survey results, and has three sections:

- Definition of Demand Response
- Survey Results
- Demand Response Developments at the FERC, and Barriers to Demand Response

Definition of Demand Response

The definition of demand response used in the survey and this report is:

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

The demand response program types and definitions in the 2012 FERC Survey conform to those used by NERC's Demand Response Availability Data System (DADS). This common terminology allows for some comparison with the DADS data. Table 4.1 contains the program classifications included in the 2012 Survey. Definitions for each of the classifications can be found in the **Appendix C** glossary.

Table 3-1. Demand response program types in the 2012 FERC Survey

Incentive-Based Programs	Time-Based Programs
• Demand Bidding and Buyback • Direct Load Control • Emergency Demand Response • Interruptible Load • Load as Capacity Resource • Non-Spinning Reserves • Regulation Service • Spinning Reserves	• Critical Peak Pricing with Control • Critical Peak Pricing • Peak Time Rebate • Real-Time Pricing • Time-of-Use Pricing • System Peak Response Transmission Tariff

Note: The 2012 FERC Survey also included an "Other" category for demand response program types that were not classified in either the Incentive-based DR Programs or Time-based Programs classifications.

Survey Results

Analytical Approach

Reported and estimated data on demand response and time-based rate programs are presented below. As with prior year Reports, the approach taken was to gather information via survey and to also supplement the data with Form EIA-861 data to report "annual resource contribution" as required in EPAct Section 1252(e)(3)(C). Values that are labeled as "reported" reflect the peak reduction (potential and actual) reported by entities in their survey responses. Values labeled as "estimated" represent an estimate of U.S. total peak reduction, and were derived using supplemental FERC and Form EIA-861 data, along with statistical methods, to fill in missing data. A detailed explanation of these estimation methods can be found in **Appendix H**.

Both reported and estimated demand response peak reduction are adjusted to minimize double-counting. **Appendix D** describes the methods Staff used to address double counting in the peak reduction data in more detail.

Summary of Report Findings

According to FERC Survey data, reported potential peak reduction in the U.S. increased from 2010 to 2012 by more than 10,000 MW, from 53,062 to 66,351 MW in 2012. This represents a 25 percent increase in reported potential peak reductions from demand response. Figure 3-1 illustrates a steady national increase in demand response capability[50] across all FERC survey years.

While demand response capability in the U.S. has steadily increased over the past few years, the key contributors to this trend vary across customer class, ownership type, and program type. The following sections summarize the 2012 FERC Survey findings on demand response.

<u>Growth in Reported Potential Peak Reduction by Customer Class</u>

Growth in reported potential peak reduction from 2006 to 2012 occurred among all customer classes, as illustrated in Figure 3-2.

Growth in Commercial and Industrial Potential Peak Reduction

Reported potential peak reductions by commercial and industrial customers increased by 31 percent, the largest increase of the three customer classes. This increase is due to new and expanded demand response programs, along with improved reporting of existing programs in the 2012 survey.[51] The Oklahoma Gas and Electric (OG&E) time-of-use program is one

[50] The terms "demand response capability" and "potential peak reduction" are used synonymously in this report.

[51] For example, the 2012 response for TVA indicates a significant increase in TVA's potential peak reduction from 2010. The apparent increase is because certain potential peak reductions reported in 2012 existed in 2010 but were not reported for TVA's programs in the 2010 FERC Survey. Similarly, the large changes in potential peak reduction from 2010 to 2012 for The Detroit Edison Company and Progress Energy Florida can be attributed to unreported 2010 data, rather than new program offerings or increased enrollment.

Figure 3-1. Total reported potential peak reduction in the 2006 through 2012 FERC Surveys

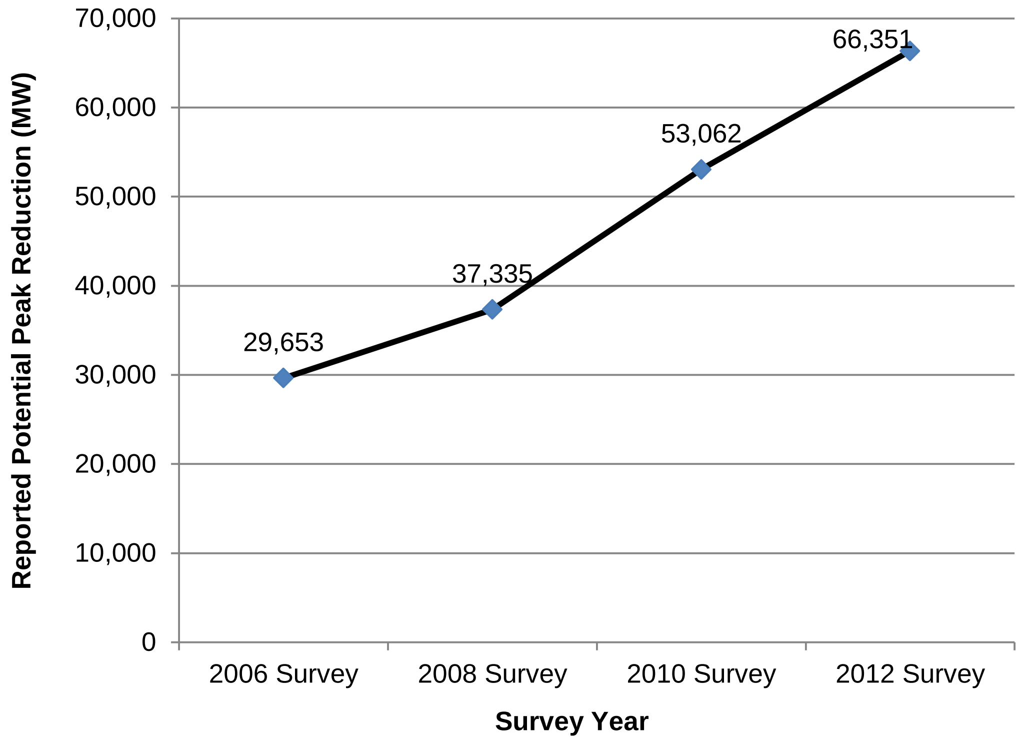
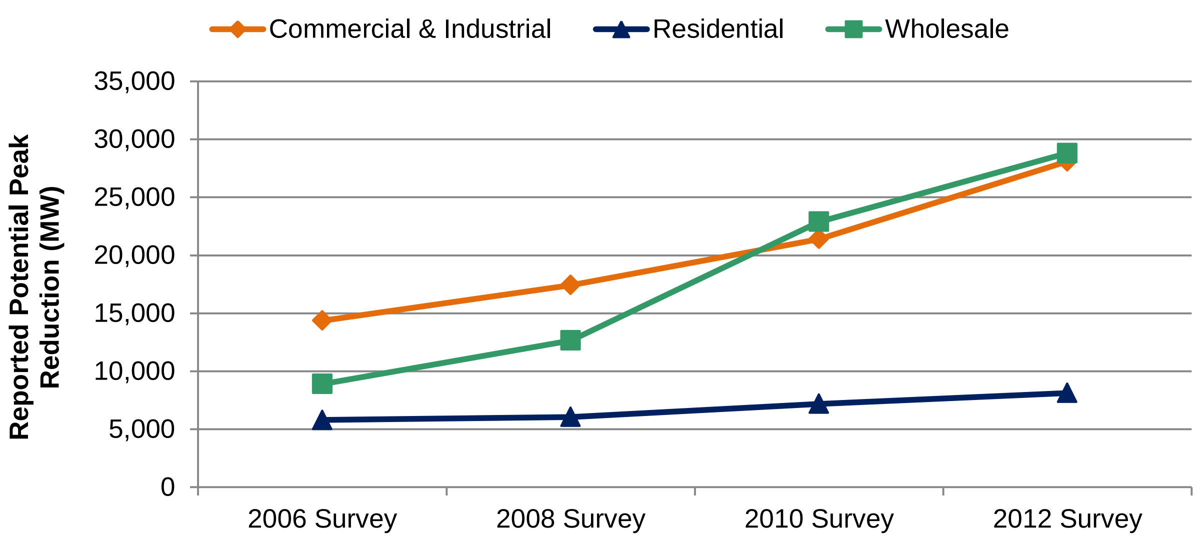


Figure 3-2. Reported potential peak reduction by customer class in 2006, 2008, 2010 and 2012



example of a significant demand response program expansion; the utility reported adding nearly 900 MW of demand response capability between 2010 and 2012 from commercial and industrial consumers. OG&E's demand response program was coordinated with an advanced metering deployment (see **Chapter 2**), and as a result, OG&E reported over 1,700 new commercial and industrial participants in its time-of-use rate program.[52]

Growth in Wholesale Potential Peak Reduction

Reported potential peak reduction for wholesale entities[53] grew by 26 percent, from 22,884 MW in 2010 to 28,807 MW in 2012. Increased enrollment of demand response resources in PJM Interconnection, LLC (PJM) and Midwest Independent Transmission System Operator (Midwest ISO) largely drove this increase, as illustrated in Figure 3-3.[54]

Figure 3-3 also shows a marked shift in the composition of wholesale demand response programs. Between 2010 and 2012, the reported potential peak reductions associated with emergency demand response programs decreased and load as a capacity resource increased, especially in the PJM and the Midwest ISO markets.

Growth in Residential Potential Peak Reduction

Reported potential peak reduction associated with residential customers grew by 13 percent, from 7,189 MW in 2010 to 8,134 MW in 2012. Seventy percent of this increase is attributable to investor-owned utilities' demand response programs. For residential customers, direct load control and time-based rates programs had the largest increases in reported potential peak reduction. For example, Baltimore Gas and Electric reported a significant increase in its residential direct load control program, from 272 MW of potential peak reduction in 2010 to 763 MW in 2012.[55]

Reported Potential Peak Reduction by Region

Nearly every region in the U.S. increased its reported potential peak reduction between 2010 and 2012, as illustrated in Figure 3-4. Reliability*First* Corporation (RFC) remained the region with the most reported potential peak reduction; RFC reported of 24,381 MW of potential peak reduction in 2012, an increase of 8,517 MW from 2010. Most of this reported growth is due to increased participation by demand response resources in PJM's forward capacity market.

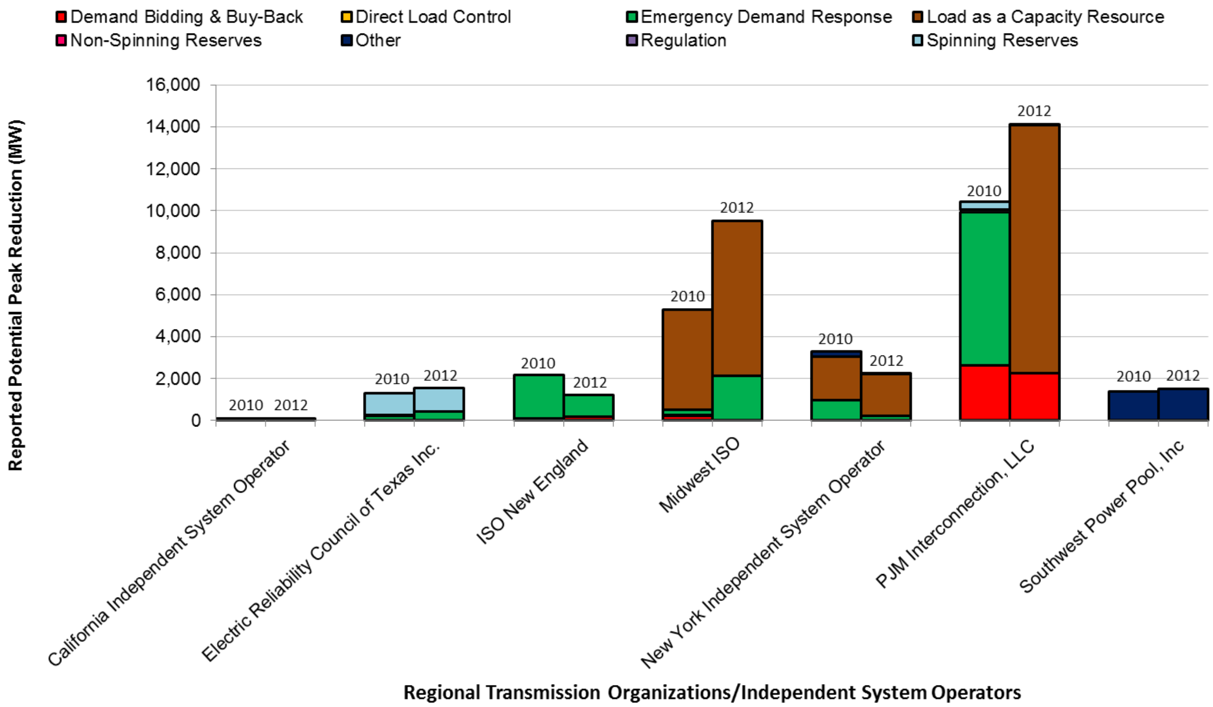
[52]Smartgrid.gov: Recovery Act Smart Grid Programs, Case Studies, Reducing Peak Demand to Defer Power Plant Construction in Oklahoma, August 2011, available at http://energy.gov/sites/prod/files/Case%20Study%20-%20Oklahoma%20Gas%20and%20Electric%20-%20Reducing%20Peak%20Demand%20to%20Defer%20Power%20Plant%20Construction%20-%20August%202011.pdf.

[53] Wholesale entities include ISOs, RTOs, curtailment service providers, wholesale power marketing agencies such as the Bonneville Power Administration, the Tennessee Valley Authority, generation and transmission corporations and joint action agencies that serve member companies, and wholesale electric marketers.

[54] Figure 3-3 shows the information provided by the ISOs and RTOs in 2010 and 2012 in their responses to the 2012 FERC Survey. This figure does not reflect any adjustments to eliminate double counting of potential peak reductions reported by both retail entities and an ISO or RTO.

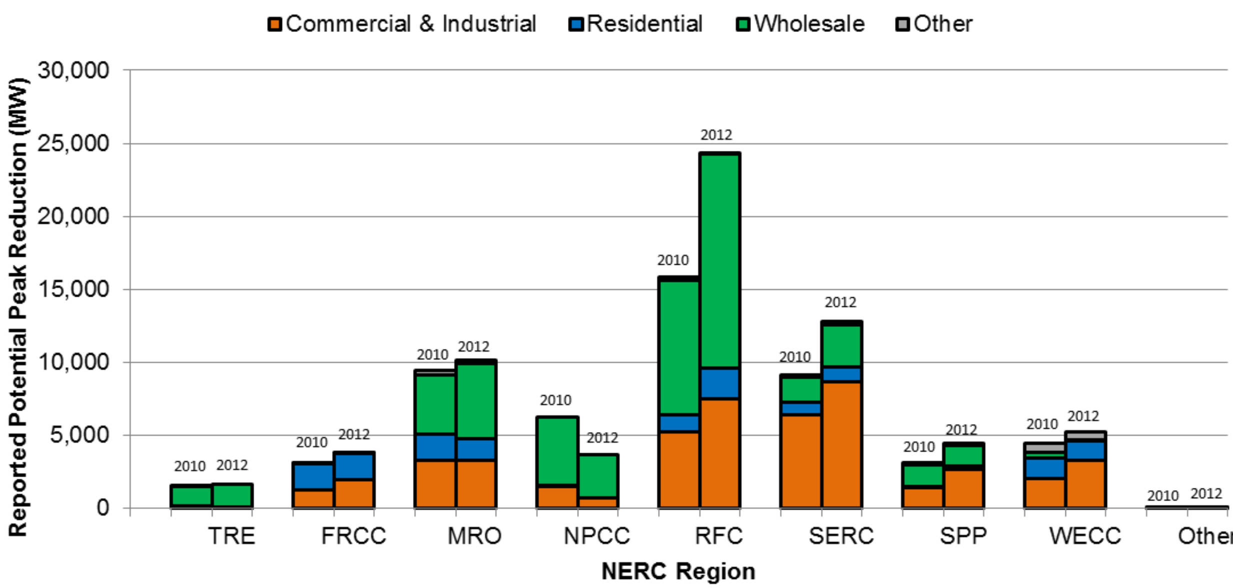
[55] Baltimore Gas and Electric deployed its direct load control program during a PJM-initiated emergency on a very hot day in July of 2011 and later measured the impact at approximately 600 MW. See http://webapp.psc.state.md.us/Intranet/Casenum/submit_new.cfm?DirPath=C:\Casenum\9100-9199\9154\Item_214\&CaseN=9154\Item_214.

Figure 3-3. Reported potential peak reduction by Independent System Operators and Regional Transmission Operators in 2010 and 2012



Note: This figure does not adjust for double-counting.

Figure 3-4. Reported potential peak reduction by region and customer class for the 2010 and 2012 FERC Surveys



SERC Reliability Corporation became the second largest NERC region for reported potential peak reduction, by adding 3,655 MW; this represents a 40 percent increase from 2010. Combined, SERC and RFC account for over 55 percent of the total U.S. reported potential peak reduction in 2012.

In the Northeast Power Coordinating Council (NPCC), the reported potential peak reduction declined by 40 percent between 2010 and 2012. A key driver for this drop in the reported potential peak reduction is due to significant declines in the amount of potential peak reduction reported by several key entities in New York.

Demand Response Program Trends

Figure 3-5 illustrates reported potential peak reduction by demand response program type.[56] These program types are organized into two main groupings: incentive-based demand response and time-based demand response programs. Traditionally, demand response programs have used incentives to encourage electricity customers to modify their electricity consumption when system reliability was threatened or market opportunities arose. Time-based programs, on the other hand, send price signals to electricity customers who voluntarily choose to modify their electricity consumption in response to these signals. As in previous years, incentive-based demand response program types represent the bulk of reported demand response potential, but time-based program types also significantly increased in 2012.

Four demand response program types made up 80 percent of the total reported potential peak reduction in 2012. These programs were:

- **Load as a capacity resource:** 29 percent of all reported demand response potential peak reduction
- **Interruptible load:** 24 percent of all reported demand response potential peak reduction
- **Direct load control:** 15 percent of all reported demand response potential peak reduction
- **Time-of-use:** 12 percent of all reported demand response potential peak reduction

The dominant program type in 2012 is load as a capacity resource (20,000 MW), a departure from the results of previous surveys. In 2010, the predominant program type was emergency demand response (13,000 MW); load as a capacity resource made up less than 9,000 MW of the total reported potential peak reduction. This change for load as a capacity resource and emergency demand response reflects the changes in wholesale market program offerings, along with changes in how PJM chose to categorize its Emergency Load Response – Full Option program.

[56] A significant challenge to developing program type classifications is linking retail programs to the classifications submitted by the ISO/RTO market operator, when a retail program is enrolled in a wholesale market program for demand response. FERC staff conducted a process to discern this linkage in order to eliminate double counting of programs in tabulations that include customer class. Further details on this process are explained in **Appendix H**.

Figure 3-5. Reported potential peak reduction by program type and by customer class in 2012 FERC Survey

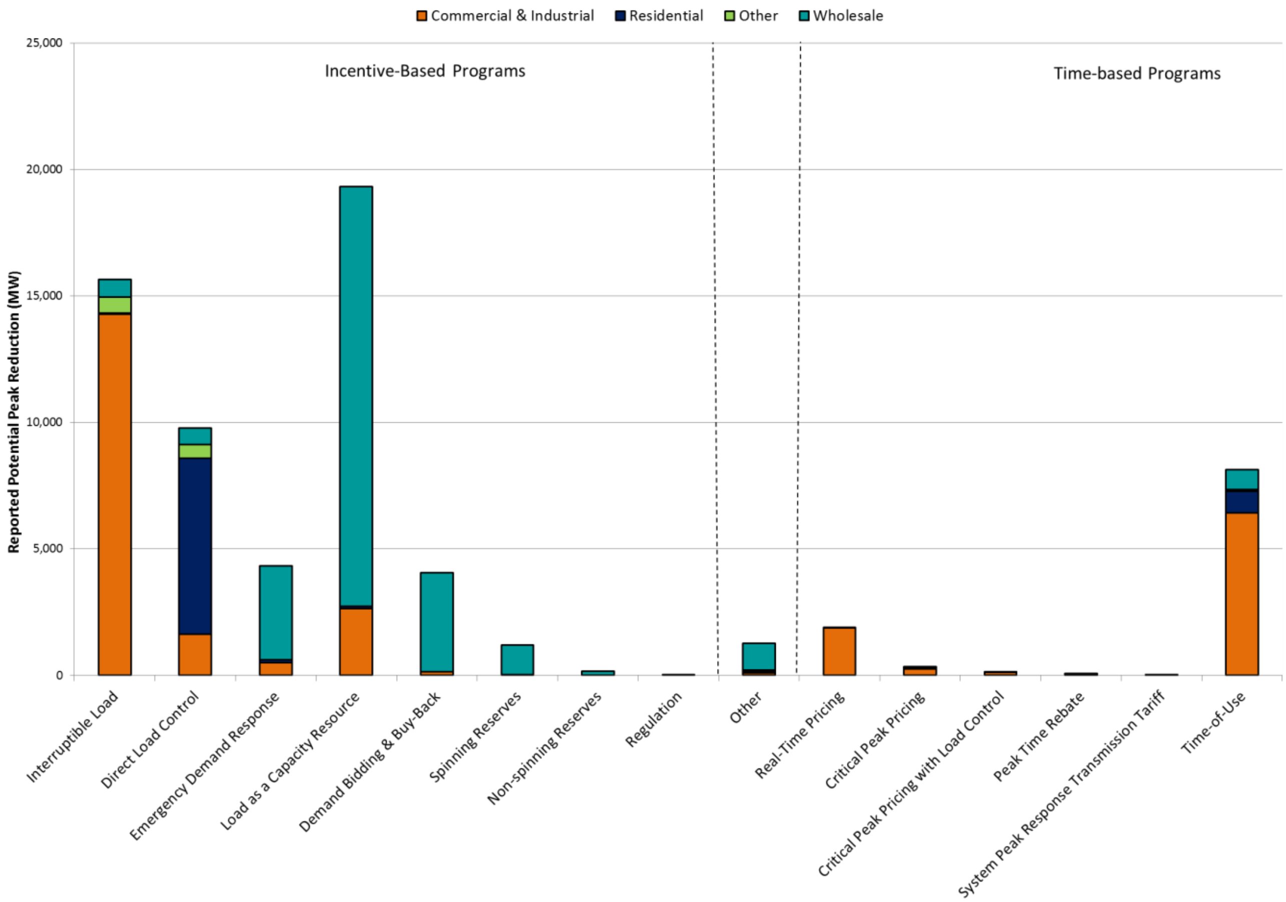


Table 3-2 lists reported peak reduction by program type and state.[57] The five states reporting the highest potential peak reductions are:

- **Michigan** – Michigan reported the highest potential peak reduction: 5,835 MW. Detroit Edison's time-of-use program for commercial and industrial customers accounts for 3,000 MW of this total.
- **Minnesota** – Although Minnesota respondents reported a slight decrease in demand response capability from 2010 to 2012, the state had second the largest reported potential peak reduction in 2012: 4,392 MW. Midwest ISO's "load as a capacity resource" demand response program consists largely of Minnesota's reliance on this demand response program type.

[57] In Table 3-2, Time-Based Demand Response Programs are the following program types: Critical Peak Pricing, Critical Peak Pricing with Load Control, Time-of-Use, Real-Time Pricing, and Peak Time Rebate. Other Incentive-Based Demand Response Programs are the following program types: Load as a Capacity Resource, Spinning Reserves, Non-Spinning Reserves, Regulation, Demand Bidding and Buy-Back, and System Peak Response Transmission Tariff.

Table 3-2. Reported potential peak reduction in Megawatts by program type and state

State	Time-Based	Direct Load Control	Other Incentive-Based	Emergency Demand Response	Interruptible Load	Other	State Total
AK	-	-	-	-	-	-	-
AL	183	17	-	-	1,647	-	1,847
AR	160	199	-	-	956	19	1,334
AZ	158	13	190	-	-	-	361
CA	381	612	1,112	256	660	-	3,020
CO	26	193	44	-	56	-	320
CT	-	-	48	339	5	-	392
DC	-	25	97	-	0	-	123
DE	117	76	186	-	20	9	408
FL	68	2,620	87	37	1,009	35	3,857
GA	686	244	7	-	328	-	1,264
HI	24	36	-	-	5	-	65
IA	3	136	346	154	605	-	1,244
ID	-	24	380	-	314	-	717
IL	9	189	1,658	58	1,298	-	3,213
IN	72	92	184	930	618	-	1,896
KS	25	65	28	20	249	-	387
KY	59	178	69	7	565	-	878
LA	-	67	-	-	-	-	67
MA	28	-	58	310	-	-	396
MD	232	822	1,357	-	66	-	2,478
ME	-	-	25	195	-	-	220
MI	3,383	240	1,306	271	550	86	5,835
MN	573	994	1,466	337	992	30	4,392
MO	84	40	-	-	83	-	207
MS	282	-	-	-	674	-	955
MT	3	-	-	-	-	-	3
NC	59	315	93	-	574	-	1,040
ND	116	295	18	6	-	-	435
NE	0	184	40	75	42	1,051	1,392
NH	-	-	11	62	-	-	73
NJ	-	112	786	9	3	-	910
NM	3	2	90	-	-	-	95
NV	-	130	-	32	-	-	162
NY	1	45	1,829	258	299	0	2,432
OH	3	88	2,536	44	475	-	3,145
OK	1,939	56	623	-	63	3	2,683
OR	-	1	14	-	6	-	21
PA	169	68	3,745	19	211	-	4,212
RI	12	-	11	74	-	-	96
SC	105	107	-	-	932	41	1,185
SD	13	605	-	18	20	-	656
TN	1,308	-	29	-	955	-	2,293
TX	4	71	1,943	420	137	2	2,577
UT	4	449	-	-	4	-	457
VA	85	118	1,988	10	82	-	2,283
VT	3	0	19	50	46	-	117
WA	1	1	1	-	20	-	23
WI	139	250	1,785	344	712	-	3,231
WV	-	-	560	4	364	-	929
WY	25	-	-	-	-	-	25

- **Pennsylvania --** Pennsylvania reported an increase in reported potential peak reduction in 2012 to 4,212 MW, largely from increased demand response participation in PJM's forward capacity market through the Emergency Load Response program.
- **Florida –** Florida continues to have a large reported potential peak reduction, and Florida's demand response capability is provided primarily by utilities' interruptible load and direct load control programs.
- **Wisconsin –** Wisconsin's reported potential peak reduction is primarily from a Midwest ISO program called "Load Modifying Resources."

Three other states had large increases in reported potential peak reduction between the 2010 and 2012: Michigan, Tennessee, and Oklahoma. These increases were due primarily to the demand response programs of Detroit Edison, the Tennessee Valley Authority, and Oklahoma Gas and Electric, respectively.

Actual Peak Reduction

In addition to providing information on reported potential peak reductions, survey respondents also provided information on actual (or realized) peak reductions that occurred in 2011 from demand response programs.[58] The actual peak reductions from demand response resources for the 2010 and 2012 FERC Surveys are presented by region in Figure 3-6 below. The 2012 FERC Survey respondents identified a total of 20,256 MW of actual peak reductions from demand response resources, representing use of 31 percent of the total reported potential peak reduction. This represents an increase from the 2010 Survey in actual peak reductions from demand response.

Figure 3-7 compares the 2012 reported potential peak reduction to actual peak reduction by region. While RFC reported the highest potential peak reduction, it reported using only 15 percent of this potential.[59] Every other NERC region used at least 25 percent of its potential demand response capability; NPCC realized 85 percent and TRE 90 percent of its reported potential peak reduction.

Estimated Potential Peak Reduction by Region

The above values for reported potential peak reduction likely understate the total potential peak reduction capability in the U.S. because not all those surveyed responded and for other reasons. Therefore, staff took steps to estimate the potential peak reduction of non-responding entities, using FERC Survey data and other sources of information, such as Form EIA-861 data.[60] The result is called the estimated potential peak reduction, in contrast to the reported potential peak reduction presented above.

[58] As a means of confirming the data, if the actual demand response peak reduction was larger than the reported potential peak reduction, the reported potential peak reduction was set equal to the actual demand response peak reduction.

[59] The ratio in RFC was low because no actual peak reductions from demand response resources were reported by the two of the largest programs in the RFC region – Detroit Edison's commercial and industrial time-of-use program and Commonwealth Edison's commercial and industrial interruptible load program. The RFC actual-to-potential ratio for the remaining programs reported was 45 percent.

[60] The estimation methodology is described in **Appendices D** and **H**.

Figure 3-6. Reported actual peak reduction by NERC region between 2010 and 2012 FERC Survey years

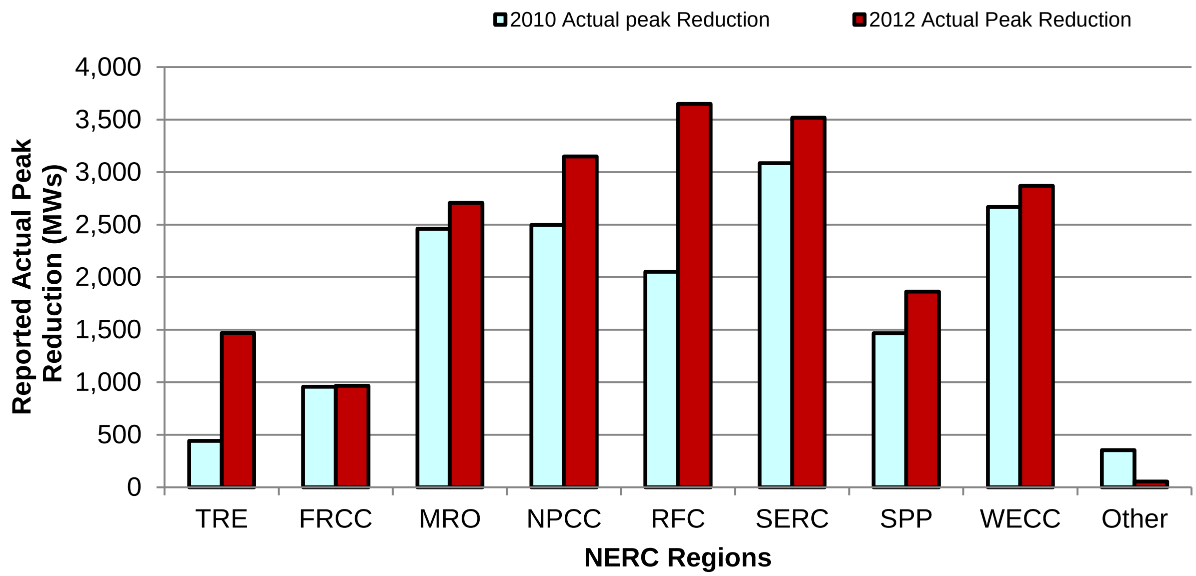


Figure 3-7. 2012 FERC Survey reported potential and actual peak reduction by region

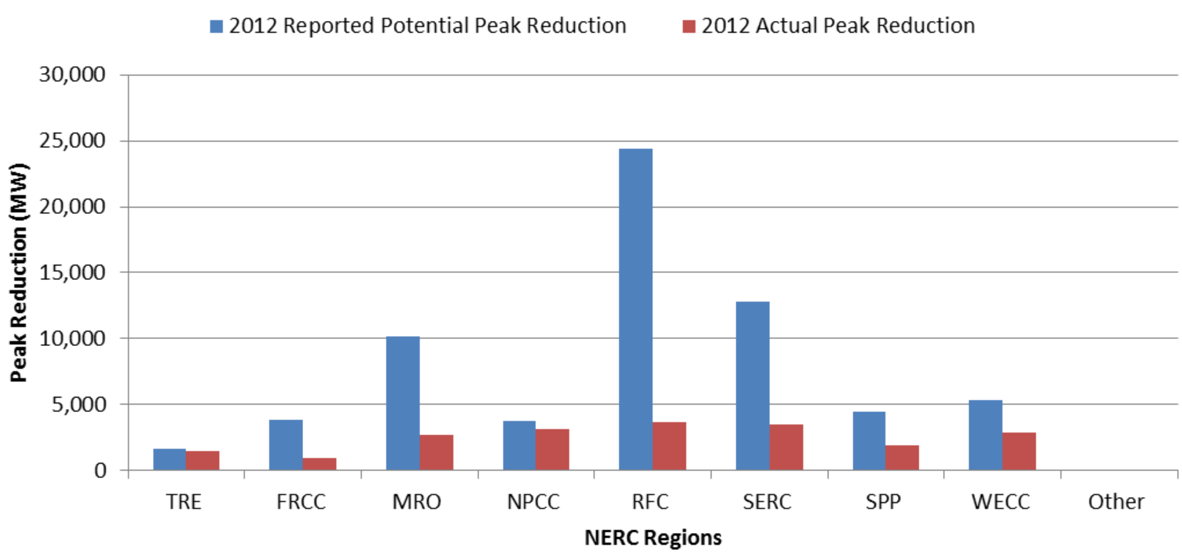


Figure 3-8 compares the estimated potential peak reduction by NERC region and customer class between 2010 and 2012. Total estimated potential peak reduction is 71,654 MW, an increase of almost 13,000 MW from 2010. RFC remained the region with highest estimate of potential peak reduction, with a total of 25,356 MW in 2012, an increase of 8,025 MW from the estimated 2010 potential peak reduction.

Figure 3-8. Estimated potential peak reduction by region and customer class in 2010 and 2012

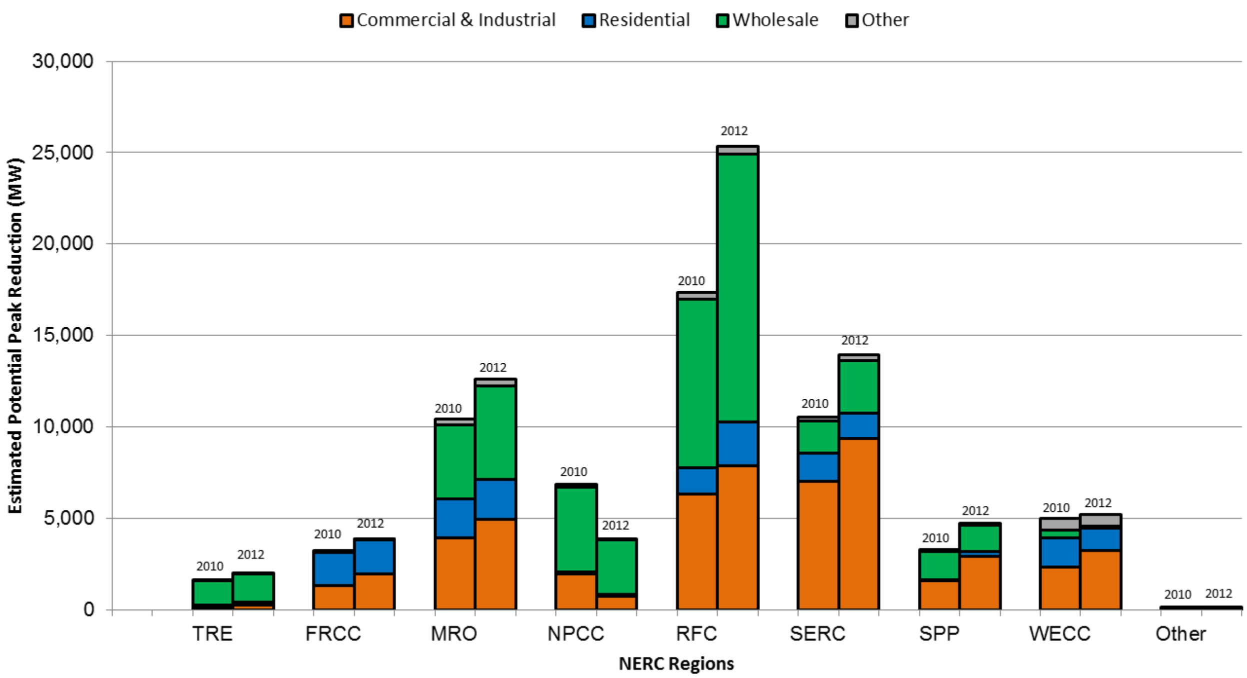


Figure 3-9 presents the estimated potential peak reduction by entity type and customer class across the 2010 and 2012 surveys. Investor-owned utilities remained the entity type with the largest estimated potential peak reduction, 27,476 MW in 2012. Commercial and industrial customers accounted for 75 percent of the estimated potential peak reduction for investor-owned utility demand response programs. ISO and RTO programs' estimated potential peak reduction increased by 20 percent to 25,489 MW in 2012.[61] Federal and state entities added an estimated 4,600 MW of estimated potential peak reduction between 2010 and 2012.

Plans for New Demand Response Programs

FERC Survey respondents were asked to "Provide your entity's near- and long-term plans for new demand response programs and time-based rates/tariffs." Table 3-3 summarizes these responses for three time periods. Direct load control programs were the dominant planned program type, followed by time-of-use rates programs and interruptible programs for all three time periods. The three main and roughly equal contributors to new demand response planned for 2012 comes from direct load control, interruptible load, and load as a capacity resource. For programs beginning in 2013 and 2014, 80 percent of the planned demand response from new programs was reported to come from an interruptible program or load as a capacity resource program.

[61] The estimated potential peak reductions attributed to RTO/ISO programs were reduced according to the methodology described in **Appendix D** to eliminate double-counting of retail demand response programs enrolled in wholesale market programs.

Figure 3-9. Estimated potential peak reduction by entity type and customer class in 2010 and 2012

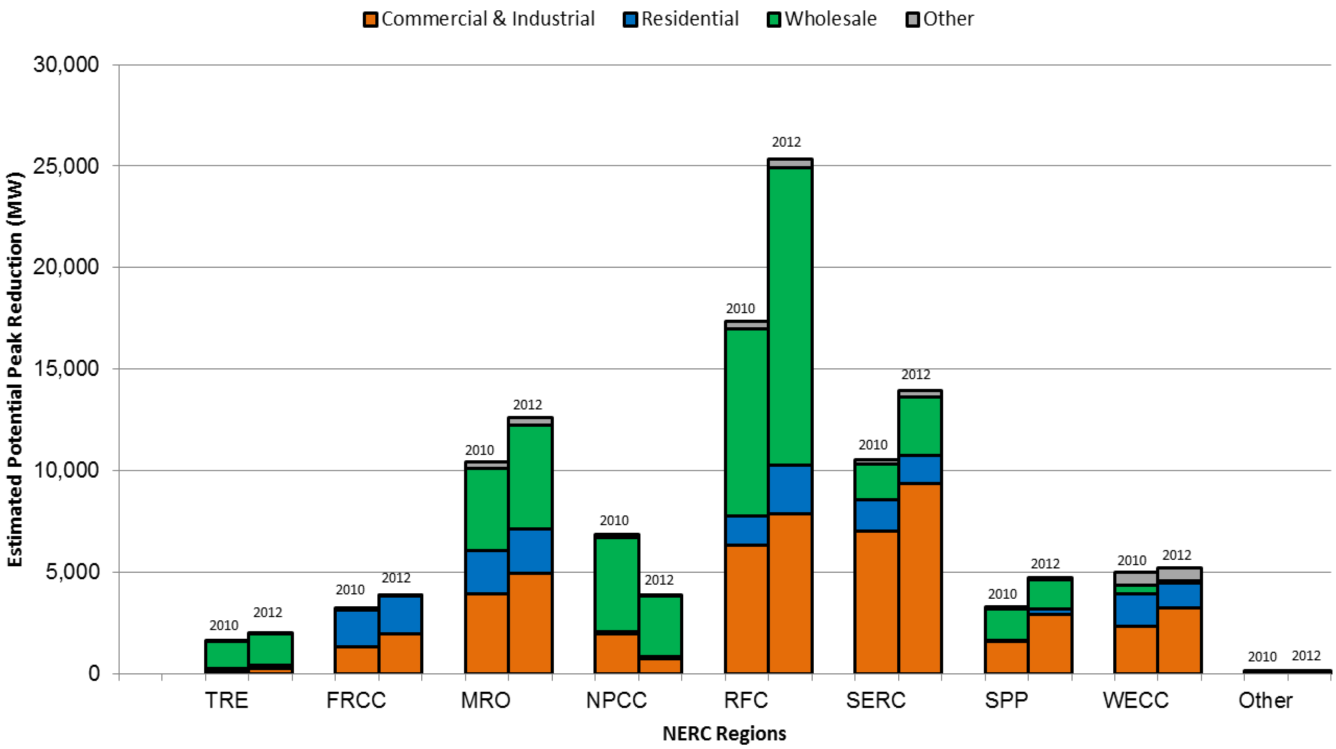


Table 3-3. Reported plans for new demand response programs and time-based rates/tariffs

	During Calendar Year 2012		During Calendar Years 2013 and 2014		During Calendar Years 2015 through 2017	
Program Type	Number of Programs	Potential Peak Reduction (MW)	Number of Programs	Potential Peak Reduction (MW)	Number of Programs	Potential Peak Reduction (MW)
Direct Load Control	489	4,579	38	884	18	291
Interruptible Load	20	5,842	15	9,696	6	211
Critical Peak Pricing with Controls	3	1	1	31	2	1
Load as Capacity Resource	9	5,906	5	9,837	-	-
Spinning Reserves	3	370	4	747	2	350
Non-Spinning Reserves	4	281	4	667	2	185
Emergency Demand Response	9	1,243	8	1,658	-	-
Regulation Service	2	60	1	75	-	-
Demand Bidding and Buyback	4	-	-	-	-	-
Time-of-Use Pricing	40	373	27	24	18	7
Critical Peak Pricing	8	12	12	15	9	14
Real-Time Pricing	3	-	5	125	6	1
Peak Time Rebate	7	64	5	3	1	-
System Peak Response Transmission Tariff	1	5	-	-	3	5
Other	7	222	6	691	2	101

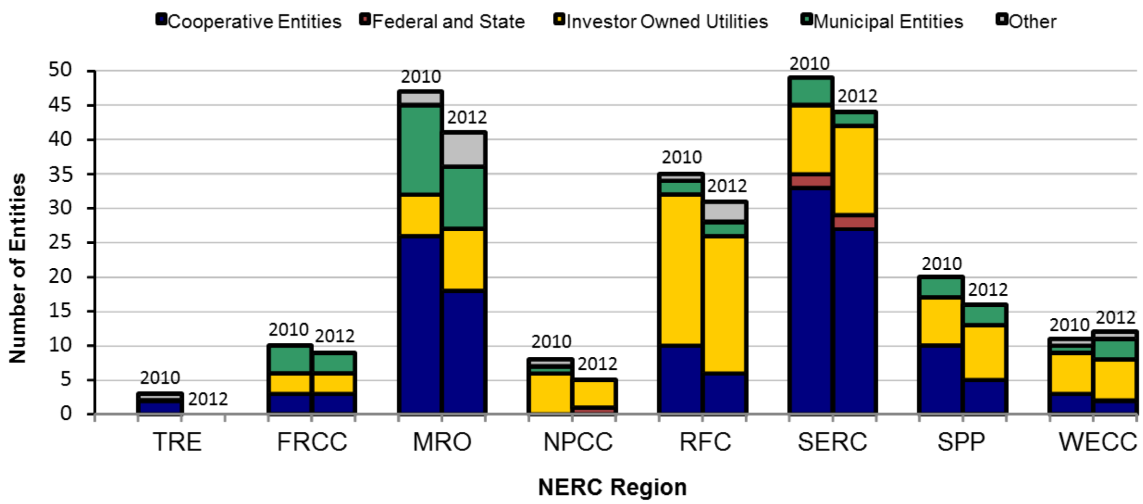
Participation in Demand Response Programs

This section discusses the reported participation of entities and customers in four specific types of demand response program: Interruptible Load, Direct Load Control, Time-of-Use, and Real-Time Pricing. Information on how many entities offer these programs and how many customers participate can provide insights into trends and regional differences.

Interruptible Load Demand Response Programs

Figure 3-10 illustrates changes in the number of entities providing interruptible load demand response between 2010 and 2012 by NERC region and entity type. Overall, the total number of entities providing interruptible service decreased from 183 providers in 2010 to 158 in 2012.[62] Cooperatives reported the largest decrease between 2010 and 2012 in the number of entities that operate interruptible demand response programs; a lower FERC Survey response rate for cooperatives may explain the decrease.

Figure 3-10. Number of entities reporting interruptible/curtailable rates by region and type of entity in 2010 and 2012[63]



Direct Load Control Demand Response Programs

The number of customers enrolled in a direct load control program by region is provided in Figure 3-11, along with the proportion of total retail customers by NERC region. The region with the most customers participating in direct load control programs in both 2010 and 2012 is RFC; however, FRCC and MRO had the highest proportions of retail customers participating in these programs. Over 12 percent of MRO's retail customers and almost 15 percent of FRCC's retail customers reportedly participated in direct load control programs in 2012.

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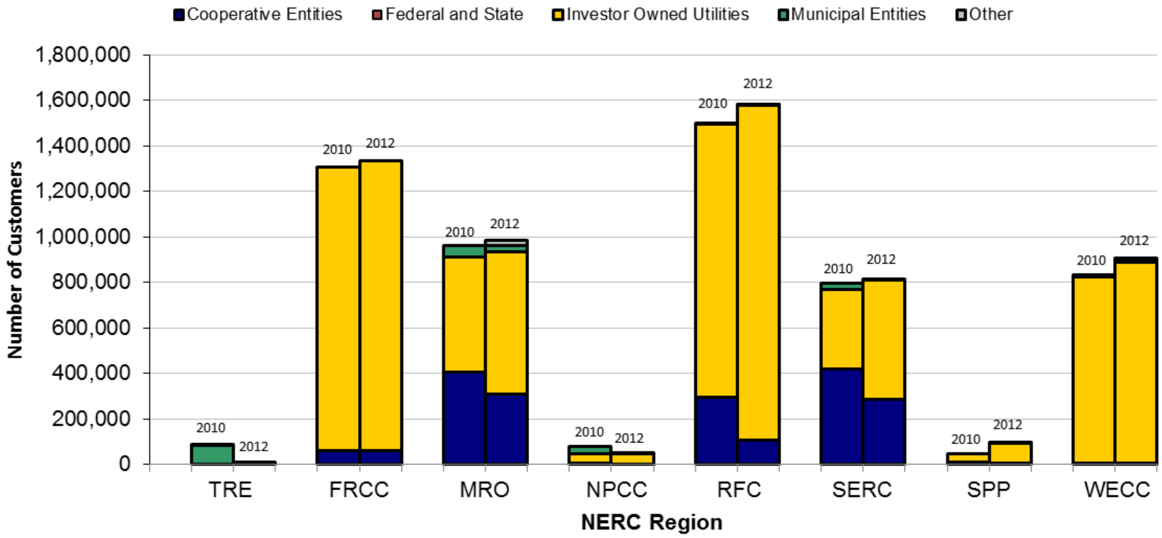
[62] The 2010 Report contains the number of interruptible/curtailable rate programs, rather than the number of entities reporting one or more of these types of programs. Figure 3-10 reflects the number of entities offering these programs in the 2010 FERC Survey.

[63] For the following figures that summarize entity and customer participation in demand response, the category "Cooperative Entities" refers to cooperatives, generation and transmission cooperatives, and political subdivisions. Similarly, municipal utilities and municipal marketing authorities are combined into "Municipal Entities." Federal entities, such as Southwestern Power Administration, and state utilities, such as the Arizona Power Authority, are combined into "Federal and State." Unless specifically identified, "Other" refers to curtailment service providers, retail power marketers, regional transmission organizations and independent system operators.

Figure 3-11. Reported number of customers enrolled in direct load control programs by region and type of entity in 2010 and 2012



	TRE	FRCC	MRO	NPCC	RFC	SERC	SPP	WECC	Other
Percent of total estimated customers in the region in a direct load control program	0.11%	14.54%	12.15%	0.25%	4.39%	2.28%	1.43%	3.09%	4.59%

Time-of-Use Demand Response Programs

Figure 3-12 illustrates the number of entities reporting residential time-of-use rates by NERC region and entity type. The number of entities offering residential time-of-use rate demand response programs increased slightly, from 144 in 2010 to 151 in 2012.[64] MRO continued to be the highest: 52 entities in the region reported offering a time-of-use rate for residential customers; over half of these programs were offered by municipally owned utilities in 2012.

While the number of entities offering residential time-of-use rates has been relatively constant from 2010 to 2012, Figure 3-13 indicates that the number of residential customers utilizing time-of-use rates is rising. The total number of residential customers on a time-of-use rate increased from 1.1 million in 2010 to almost 2.1 million in 2012, with almost all of this growth occurring in RFC. Approximately 800,000 new residential customers began using time-of-use rates in RFC between 2010 and 2012, primarily under the Potomac Electric Power Company and Delmarva Power and Light program expansions.

[64] The 2010 Report contains the number of residential time-of-use programs, rather than the number of entities reporting one or more of these types of programs. Figure 3-12 reflects the number of entities offering these programs in the 2010 FERC Survey.

Figure 3-12. Number of entities reporting residential time-of-use rates by region and type of entity in 2010 and 2012

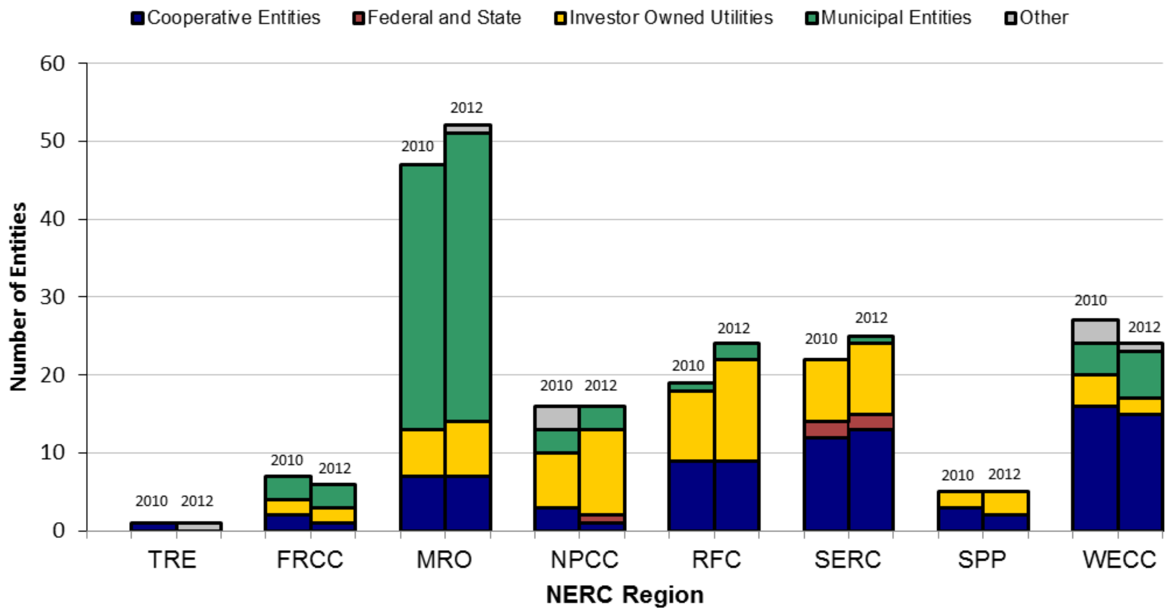
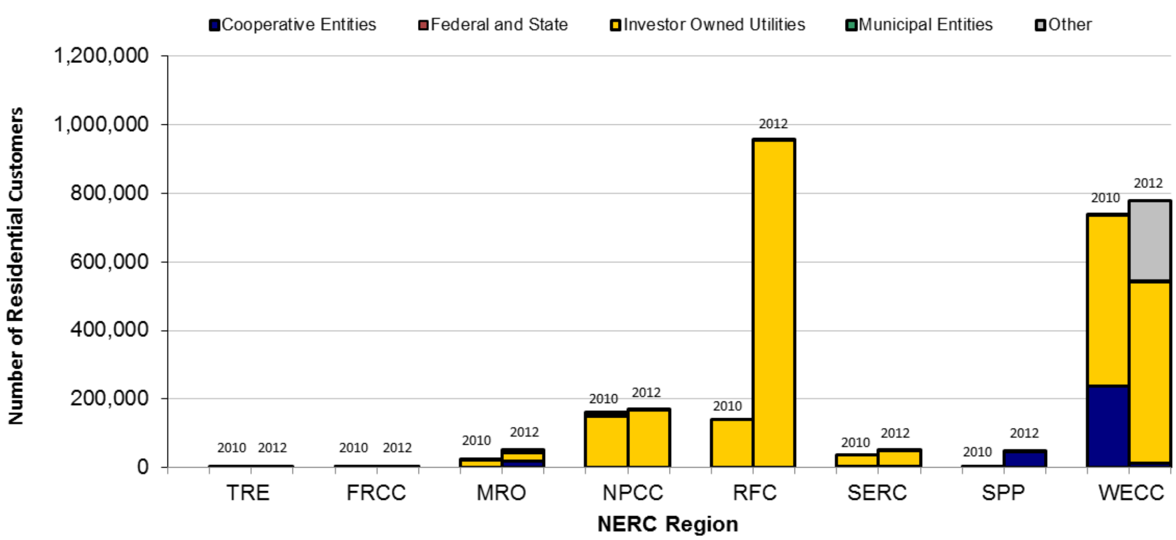


Figure 3-13. Reported number of residential customers enrolled in time-of-use rates by region and entity type in 2010 and 2012

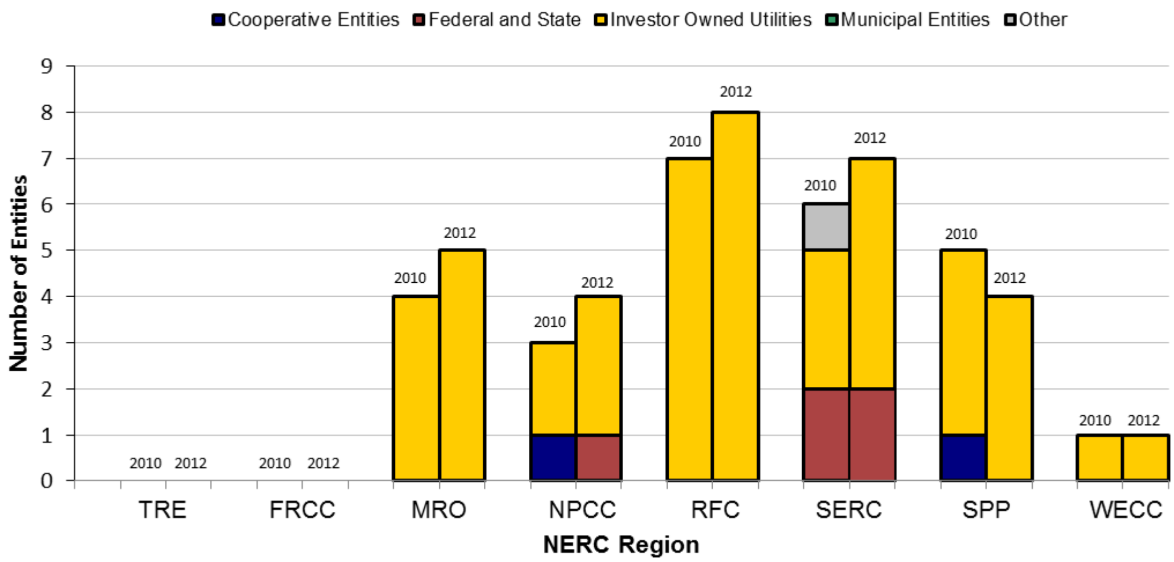


The large increase in time-of-use participation in the RFC region illustrates a shift from previous FERC Survey trends. In previous years, WECC was the dominant time-of-use demand response region; however, residential time-of-use program customers in WECC increased only slightly between the two survey years, to just over 775,000 customers (about 2.7 percent of all WECC customers).

Real-Time Pricing Programs

The number of entities that reported offering real-time pricing programs is presented in Figure 3-14, by region and entity type. Twenty-eight entities reported offering real-time pricing in 2012, a slight increase from the 25 entities reporting in 2010. Nearly all of the entities offering real-time pricing programs are investor-owned utilities.[65]

Figure 3-14. Number of entities reporting retail real-time pricing by region and entity type in 2010 and 2012



Demand Response Activities at the FERC

Since the publication of the November 2011 *Assessment of Demand Response and Advanced Metering*, the Commission has continued to further the goal of comparable treatment of demand response resources in wholesale markets, as well as to follow the provisions of law requiring it to develop a plan to realize the national potential for demand response.

This section summarizes the key demand response developments and actions undertaken by the Commission since the prior report, including several rulemakings and key demand-response-related RTO/ISO orders.

Commission Demand Response Activities

The Commission continues to assess and monitor the wholesale electric power markets under its jurisdiction, to ensure that resources that are technically capable of providing demand response services are treated comparably to supply-side resources. This section summarizes FERC actions taken in the past year that affect demand response resources in wholesale markets, including action the Commission has taken to address compensation and

[65] The 2010 Report contains the number of RTP programs, rather than the number of entities reporting one or more RTP program. Figure 3-14 reflects the number of entities offering these programs in the 2010 FERC Survey.

measurement and verification as well as Commission actions in response to RTO and ISO proposals related to demand response.

Commission Rulemakings on Demand Response Issues

NAESB Wholesale Demand Response Measurement and Verification NOPR

In April 2012, the Commission issued a Notice of Proposed Rulemaking (NOPR) to amend its regulations to incorporate by reference NAESB's business practice standards on the measurement and verification of demand response and energy efficiency resources that participate in organized wholesale electricity markets. The proposed demand response measurement and verification standards would add specificity to existing standards in several areas, including meter data reporting, advanced notification, telemetry, and meter accuracy. The Commission requested comments on whether the proposed demand response measurement and verification standards are sufficiently detailed to provide transparent measurement and verification across regions, and whether greater detail or conformity across regions would be appropriate. By contrast, the proposed energy efficiency measurement and verification standards would provide more substantial detail than the demand response standards to ensure effective evaluation of the performance of energy efficiency products and services. The proposed wholesale energy efficiency standards include four measurement and verification methodologies, as well as a mechanism for resource providers to propose, and organized markets to consider, alternative approaches.[66] Comments on the NOPR were received on July 30, 2012 and the Commission is evaluating those comments.

Order No. 745 Compliance Orders

Order No 745,[67] issued in March 2011, requires that RTOs and ISOs pay demand response resources participating in the day-ahead and real-time wholesale energy markets the locational marginal price (LMP) when two conditions are met: demand response resource are capable of balancing supply and demand in the wholesale energy markets, and dispatching and paying LMP to demand response resources is cost-effective as determined by a net benefits test. All six ISOs and RTOs, have made filings to comply with Order No. 745. Commission orders approving the compliance filings of PJM, ISO-New England (ISO-NE), and the Midwest ISO are discussed below. Commission proceedings on the compliance filings for the California ISO (CAISO), New York ISO (NYISO), and SPP remain open at the time of this writing.

<u>PJM Order No. 745 Compliance (Docket No. ER11-4106)</u>

PJM submitted its Order No. 745 compliance filing in July 2011. In its compliance filing, PJM proposed to revise its existing compensation methods for participants in PJM's Economic Load Response programs from LMP less applicable avoided generation and transmission charges in all hours to LMP in hours when a net benefits test is passed. PJM also proposed changes to (1) rules governing self-scheduling, (2) the customer baseline load methodology used to measure demand reductions in the energy and ancillary services

[66] *Standards for Business Practices and Communication Protocols for Public Utilities*, 139 FERC ¶ 61,041 (2012).

[67] *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, 76 FR 16,658 (Mar. 24, 2011), FERC Stats. & Regs. ¶ 31,322 (2011) (Order No. 745), *order on reh'g,* 137 FERC ¶ 61,215 (2011).

markets, and (3) how the costs for demand response are allocated. On December 15, 2011, the Commission accepted PJM's filing, subject to an additional compliance filing.[68] The Commission found that PJM's proposed tariff revisions went beyond what was required to comply with Order No. 745, which applies only if a demand response resource has the capability to balance supply and demand and if dispatch of the demand response resource is cost-effective as determined by a net benefits test. PJM submitted another compliance filing in March 2012 in response to the December order, which was accepted by the Commission in June 2012.[69]

ISO-New England Order No. 745 Compliance (Docket No. ER11-4336)

ISO-NE submitted its Order No. 745 compliance filing and proposed tariff revisions in August 2011. As part of its compliance filing, ISO-NE proposed (1) a net benefits test that established a threshold price for submitting demand response bids, (2) adjustments to its current baseline calculation methodology for measuring demand reductions, and (3) allocating costs hourly in proportion to the ISO-NE Real-Time Load Obligation[70] on a system-wide basis. ISO-NE proposed implementing these changes in two stages that would fully integrate demand response resources into its energy market by June 2016. The Commission accepted ISO-NE's Order No. 745 compliance filing in January 2012,[71] subject to a further compliance filing. ISO-NE submitted this second compliance filing in March 2012, which was accepted by the Commission in May 2012.[72]

Midwest ISO Order No. 745 Compliance (Docket Nos. ER12-1266 and ER11-4337)

The Midwest ISO submitted its Order No. 745 compliance filing in August 2011. It proposed to establish a monthly Net Benefits Price Threshold. The Midwest ISO also proposed to pay the applicable LMP to cost-effective demand response resources that clear either the day-ahead or real-time energy market. Additionally, the Midwest ISO proposed to allocate the costs associated with compensating demand resources in the real-time energy market to market participants located within the reserve zone of demand response resources that either purchase energy and benefit from reduced LMPs or serve load and avoid selling energy to retail customers at a loss. The Midwest ISO proposed to allocate any remaining costs to all load-serving entities systemwide on a *pro rata* load ratio share basis. The Commission accepted this compliance filing in part and rejected it in part in December 2011.[73] The Midwest ISO submitted its second Order No. 745 compliance filing in March 2012; d the Commission accepted the Midwest ISO's Order No. 745 compliance filing in July 2012.[74]

Order No. 719 Compliance Orders

The Commission issued Order No. 719 in October 2008 to improve the operation of organized wholesale electric power markets in several areas: (1) demand response, including

[68] *PJM Interconnection, L.L.C.*, 137 FERC ¶ 61,216 (2011).
[69] *PJM Interconnection, L.L.C.*, 139 FERC ¶ 61,256 (2012).
[70] Real-Time Load Obligation refers to the total load serving entities' MWh load obligation of market participants at each location during a given hour of operation. *See* ISO-NE Tariff, section III.3.2.1(b)(i).
[71] *ISO New England Inc.*, 138 FERC ¶ 61,042 (2012).
[72] *ISO New England Inc.*, Docket No. ER11-4336-005 (May 29, 2012) (delegated letter order)
[73] *Midwest Indep. Transmission Sys. Operator, Inc.*, 137 FERC ¶ 61,212 (2011) (Order No. 745 Compliance Order).
[74] *Midwest ISO*. 140 FERC 61,059 (2012).

pricing during periods of operating reserve shortage; (2) long-term power contracting; (3) market-monitoring policies; and (4) the responsiveness of RTOs and ISOs to their customers and other stakeholders.[75] Several compliance filings associated with Order No. 719 implementation were submitted and approved in 2012, and details on PJM and Midwest ISO's filings are provided below.

<u>PJM Order No. 719 Compliance—Scarcity Pricing (Docket No. ER09-1063-004)</u>

PJM submitted an Order No. 719[76] compliance filing and proposed tariff changes addressing shortage pricing requirements in June 2010, and the Commission accepted the changes in April 2012.[77] PJM proposed numerous tariff changes, including changes to PJM's demand response programs, based on its analysis that PJM's existing shortage pricing provisions fail to satisfy the shortage pricing requirements of Order No. 719. The Commission accepted PJM's tariff revisions and found that PJM's proposed pricing reforms would encourage existing demand response and generation resources to continue to provide supplies during shortage conditions, because these resources will be eligible to receive the prevailing energy and reserve market clearing price. In addition, the Commission found that PJM's proposal would (1) increase the accuracy of market clearing prices during shortage conditions, (2) minimize the need for out-of-market payments, and (3) provide clearer price signals to both demand response and generation resources.[78]

<u>Midwest ISO Order No. 719 Compliance (Docket Nos. ER12-1265 and ER09-1049)</u>

The Midwest ISO submitted its initial Order No. 719 compliance filing in April 2009. In this filing, MISO stated that its existing market design satisfied the requirements of Order No. 719 regarding both (1) the participation of demand response resources in ancillary services markets,[79] and (2) price formation during periods of operating reserve shortages.[80] The Midwest ISO submitted an additional filing in October 2009 that proposed tariff revisions to allow the participation of aggregators of retail customers (ARCs) in Midwest ISO's markets. The Commission accepted both Midwest ISO compliance filings in December 2011, subject to a further compliance filing. The Midwest ISO submitted its final Order No. 719 compliance filing in March 2012,[81] proposing tariff revisions regarding the provision of ancillary services by demand response resources, including measurement and verification protocols[82] and tariff revisions regarding the registration, information sharing, credit, and

[75] *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 (2008) (Order No. 719), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292 (2009), *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

[76] *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 73 Fed. Reg. 64,100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281, at P 165, *et seq.* (2008), *order on reh'g*, Order No. 719-A, FERC Stats. & Reg. ¶ 31,292 (2009), FERC Stats. & Regs. ¶ 31,292 (2009), *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

[77] *PJM Interconnection L.L.C.*, 139 FERC ¶ 61,057 (2012).

[78] *PJM Interconnection, L.L.C.*, 139 FERC ¶ 61,057 (2012).

[79] MISO April 2009 Compliance Filing, Transmittal Letter at 6-9, 11-12.

[80] *Id.* at 20-25.

[81] MISO March 14, 2012 Compliance Filing, Docket No. ER12-1265-000 (March 2012 Compliance Filing); MISO March 23, 2012 Amended Compliance Filing, Docket No. ER12-1265-001 (March 2012 Amended Filing).

[82] MISO March 2012 Compliance Filing, Transmittal Letter at 2-6.

other requirements for ARCs. The Midwest ISO proposed to compensate ARCs at the LMP.[83] The Commission accepted these proposed changes in July 2012.

Other Commission Demand Response Orders

In addition to rulemakings, the Commission also approved several revisions to RTO/ISO tariffs related to demand response resources in regional organized wholesale markets. The follow briefly describes these revisions and Commission actions.

California ISO Flexible Ramping Constraint (Docket No. ER12-50)

The CAISO proposed tariff changes to implement a flexible ramping constraint in October 2011 so as to provide CAISO with sufficient ramping capability to match real-time supply with real-time demand. The CAISO plans to procure this flexible ramping capability from committed, flexible generation resources, proxy demand resources, and participating load resources. The Commission accepted and suspended the proposed tariff changes in December 2011 to establish hearing and settlement judge procedures.[84] CAISO is continuing to work on developing a new flexible ramping product.

California ISO Regulation Energy Management (Docket No. ER11-4353)

In August 2011, CAISO submitted proposed revisions to its tariff to implement regulation energy management. Regulation energy management allows energy storage resources or demand response to provide regulation service. Under the proposal, scheduling coordinators for non-generator resources within CAISO's balancing authority area may choose to use regulation energy management if they require regulation resources. The Commission accepted CAISO's proposal in November 2011.[85]

Midwest ISO's Extended Locational Marginal Price Algorithm (Docket No. ER12-668)

The Midwest ISO filed proposed revisions to its tariff in December 2011 to improve the accuracy of pricing in its energy and operating reserve markets by allowing more resources, including emergency demand resources, to set the LMP in the day-ahead and real-time energy markets as well as the market clearing price in the day-ahead and real-time operating reserve markets. The Commission accepted Midwest ISO's proposal in July 2012, subject to further compliance filings.[86]

PJM Price Responsive Demand (Docket No. ER11-4628)

PJM filed proposed tariff changes in September 2011 to support the development of price responsive demand, an initiative for end-use customers to vary their load in response to wholesale electricity prices. PJM proposed to incorporate this demand responsiveness by allowing load serving entities (and other market participants), with the approval of their relevant regulatory authorities, to commit to reducing loads to specified levels when prices rise during emergency conditions. The mechanism is designed to allow the installed capacity requirement of load serving entities to be reduced to reflect the lowered need for peaking

[83] *Id.* at 7-16.
[84] California Independent System Operator Corporation, 137 FERC ¶ 61,191 (2011).
[85] *California Independent System Operator Corporation*, 137 FERC ¶ 61,165 (2011).
[86] *Midwest ISO.*, 140 FERC ¶ 61,067 (2012).

capacity due to price responsive demand commitments. Following a staff technical conference on this proposal, the Commission accepted PJM's filing effective May 15, 2012, subject to further compliance.[87]

PJM Targeted Sub-Zonal Dispatch (Docket No. ER12-1372)

PJM filed tariff revisions in March 2012 to support sub-zonal dispatch, and recognize the expanded selection of demand resource products. Sub-zonal dispatch would allow PJM to dispatch a targeted set of demand response resources to address localized emergency events, rather than calling on the full set of demand resources available within a zone. To implement sub-zonal dispatch, PJM also proposed requiring demand response providers to have the capability to receive electronic dispatch signals from PJM. PJM proposed that responses to sub-zonal dispatch be voluntary at first, with no penalty for non-performance. After a two-year transition period, PJM proposed assessing compliance charges for inadequate response to sub-zonal dispatch only if the sub-zone is defined and posted the day before the Load Management event. The Commission accepted PJM's proposed tariff revisions, which were effective June 1, 2012.[88]

PJM Regulation-Only CSPs (Docket No. ER12-1430)

PJM filed proposed tariff changes in April 2012 to expand the opportunity for demand response providers and end-use customers to participate in PJM's frequency regulation market. PJM's proposed changes would create an "Economic Load Response Regulation Only Registration" to (1) simplify the aggregation process for regulation-only resources; (2) allow two different demand response providers in the PJM Economic Load Response Program to provide demand response services to the same end-use customer, where one demand response provider provides regulation service; and (3) allow equipment-specific load data, rather than load data for an entire facility, to be submitted to verify that the regulation service that cleared the market was actually provided. The Commission accepted these tariff revisions in June 2012.[89]

PJM M&V Changes (Docket No. ER11-3322)

PJM filed proposed changes to its tariff in April 2011 to clarify how the performance of demand response capacity resources is measured during emergency dispatch and performance verification testing. PJM stated that its current rules allowed curtailment service providers to offset some customers' underperformance with the "excess" performance of other end-use customers in its portfolio, and argued that this type of aggregation gives the appearance of a greater supply of capacity. PJM proposed to modify the reference point of capacity demand response load reductions so that each end-use customer's actual load reduction results in a metered load that is less than the customer's peak demand (i.e., the peak contribution identified by PJM). After a technical conference on the subject, the Commission accepted PJM's proposal in November 2011 requiring PJM to submit a compliance filing to modify and clarify its proposal.[90]

[87] *PJM Interconnection L.L.C.*, 139 FERC ¶ 61,115 (2012).
[88] *PJM Interconnection L.L.C.*, 139 FERC ¶ 61,165 (2012).
[89] *PJM Interconnection L.L.C.*, 139 FERC ¶ 61,172 (2012).
[90] *PJM Interconnection L.L.C.*, 137 FERC ¶ 61,108 (2011).

Other Demand Response Developments and Issues

In addition to FERC rulemakings and RTO/ISO demand response initiatives, several noteworthy developments and activities occurred within and outside government. The following summarizes (1) the National Forum on the National Action Plan on Demand Response, (2) ARRA-funded consumer behavior studies, (3) the NERC DADS program, (4) demand response events during the summer of 2012, and (5) selected state activities.

National Forum on the National Action Plan on Demand Response

Over the past year, the U.S. Department of Energy, with support from Commission staff, conducted a National Forum on the National Action Plan on Demand Response.[91] Working groups comprised of national demand response experts and practitioners are preparing reports that identified knowledge and research gaps in four areas (cost-effectiveness, measurement and verification, program design and delivery, and modeling and tools) and the actions needed to help implement the action items included in the National Action Plan on Demand Response.

U.S. Department of Energy-Sponsored Consumer Behavior Studies

The ARRA includes funding and support for nine utility-sponsored consumer behavior studies as part of ARRA's SGIG program. The SGIG studies are designed to assess customer acceptance and adoption of time-based electricity rates and enabling technologies, such as advanced metering.[92] The studies, carried out in nine states and varying in size from 500 to 60,000 participants, assess consumer usage of a variety of technologies, such as web portals, in-home displays, and programmable communicating thermostats. The SGIG studies also examine several rate structures, from simple time-of-use rates, to more complex critical peak pricing plans, with some combinations offered on either an opt-in or opt-out basis. The consumer behavior studies began in 2010 and are scheduled to end in 2014. SGIG recipients are required to publish mid-term and final reports on the findings of their studies. As of July 2012, mid-term reports from Marblehead Municipal Light Department and Oklahoma Gas and Electric (OG&E) were published, along with a final SGIG consumer behavior report from OG&E. OG&E's final SmartStudy Together report suggests that customers are open to the program's new technology and time-based pricing schedules, especially programmable communicating thermostats and variable peak pricing with a critical peak component. Final results from the remaining SGIG consumer behavior studies are expected between 2012 and 2014.

[91] For more information on the National Action Plan on Demand Response, see *National Action Plan on Demand Response*, Federal Energy Regulatory Commission, June 2010; http://www.ferc.gov/industries/electric/indus-act/demand-response/dr-potential.asp, and FERC and DOE Staff, *Implementation Proposal for the National Action Plan*, July 2011, available at http://www.ferc.gov/legal/staff-reports/07-11-dr-action-plan.pdf.

[92] Smart Grid Investment Grant Program, Project Information: Consumer Behavior Studies, Information available at http://www.smartgrid.gov/recovery_act/project_information?keys=&project%5B%5D=15.

NERC Demand Response Data Collection

NERC developed a regular data reporting system for demand response resources to measure their contribution to reliability more precisely. NERC's Demand Response Availability Data System (DADS) collects and analyzes semiannual data from several categories of industry participants,[93] and reporting entities are required to submit information for a specified reporting period about (1) individual demand response programs, and (2) each event for which demand response was deployed for reliability purposes.

NERC is implementing DADS in four distinct phases:

- Phase I was completed in 2010 and served as a pilot stage for establishing the mechanism of data collection and metrics for data analysis. It featured information on reliability-based programs that are dispatchable and controllable.
- Phase II (the current phase of the DADS program) is mandatory[94] for programs that have been in service for one year or longer and have 10 MW or more of enrolled resources.
- Phase III is expected to begin in the summer of 2013 and will add voluntary reporting of non-controllable economic demand response programs such as time-of-use rates and critical peak pricing.
- Phase IV will require reporting of all demand response resources. It is projected to begin in 2014.

The first results of the DADS program were published in NERC's 2012 State of Reliability Report.[95] The report featured Phase II DADS data collected over the summer 2011 reporting period (April 1 – September 30, 2011). From data reported by 133 entities, NERC estimates an average of 53,005 MW of reliability demand response capacity throughout all the NERC regions of the United States and Canada.[96] NERC also reports there were 664 demand response events called during the summer 2011 reporting period, with an average sustained response period of 2 hours and 51 minutes.

The NERC State of Reliability Report also summarized DADS data by NERC region and program type. The ReliabilityFirst Corporation (RFC) region had the largest demand response capacity, with 24,386 MW registered. NERC also reported that the Interruptible Load and Direct Load Control were the most prevalent program types, accounting for 32 percent and 26 percent of all programs respectively.

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[93] Responsible Entities include: Balancing Authorities, Distribution Providers, Load-Serving Entities, and Purchasing-Selling Entities that are Registered NERC Entities. See the NERC Reliability Functional Model for more detail, available at http://www.nerc.com/page.php?cid=2%7C247%7C108.

[94] DADS data reporting is mandatory for all entities on the NERC Compliance Registry, through Section 1600 data requests. See http://www.nerc.com/files/DADS%20Quick%20Facts.pdf for more information. See also https://www.midwestiso.org/Library/Repository/Meeting%20Material/Stakeholder/DRWG/2011/20111003/20111003%20DRWG%20Item%2005%20DADS%20September%20Training%20Presentation.pdf for a discussion of NERC's authority under 18 C.F.R. Section 39.2(d).

[95] North American Electric Reliability Corporation, 2012 State of Reliability Report, May 2012, available at http://www.nerc.com/files/2012_SOR.pdf.

[96] The Western Electricity Coordinating Council, the Midwest Reliability Organization, and the Northeast Power Coordinating Council cover areas of the U.S. and Canada.

Summer 2012 Demand Response Deployments

This section provides a brief overview of major summer 2012 demand response deployments by region, along with links to additional data on summer 2012 demand response events. According to the National Oceanic Atmospheric Administration (NOAA), summer 2012 was one of the hottest summers on record for the U.S.[97] Above-average temperatures drove high peak electricity loads and large deployments of demand response resources across the country.

PJM reported several large deployments of demand response resources in June and July 2012. It estimated 17,148 MW in reductions from its economic demand response program over the month of June,[98] and PJM also issued hot weather alerts for June 20-21 instructing generators and transmission owners to defer unnecessary maintenance on plants and power lines.[99] In July, PJM reported large demand response deployments from July 2-8 and July 16-18. PJM deployed economic demand response resources from July 2-8; however, no emergency demand response was dispatched over this one-week period.[100] PJM again utilized economic demand response resources on July 16, and a mix of economic and emergency demand response resources from July 17-18. In the largest deployment on July 18, PJM estimates that over 2,500 MW of economic and emergency demand response resources was deployed.[101] The largest overall economic demand response responses in PJM primarily came from Virginia, Pennsylvania, and New Jersey in June-July 2012.[102] PJM did not report any large demand response deployments during August.

New York ISO (NYISO) called upon demand response resources in June and July 2012. NYISO called upon reliability demand response resources several times during June 20-22.[103] The New York Power Authority (NYPA) also deployed demand resources participating in its Peak Reduction program for the first time on June 20, reducing hourly peak loads in New York City up to 30 MW.[104] In July, NYISO utilized reliability demand response resources on July 18, and a mix of economic and reliability demand response

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97 State of the Climate Report, July 2012, available at http://www.ncdc.noaa.gov/sotc/.

98 Load Response Activity Report, August 2012, available at http://pjm.com/markets-and-operations/demand-response/~/media/markets-ops/dsr/2012-dsr-activity-report-20120810.ashx.

99 Energy Assurance Daily, June 20, 2012, available at http://www.oe.netl.doe.gov/docs/eads/ead062012.pdf.

100 PJM Estimated Demand Response Activity July 2 – 8, 2012 Report, available at http://pjm.com/markets-and-operations/demand-response/~/media/markets-ops/demand-response/pjm-hot-days-report-for-july-2-july-8-2012.ashx.

101 PJM Estimated Demand Response Activity July 16 – 18, 2012 Report, available at http://pjm.com/markets-and-operations/demand-response/~/media/markets-ops/demand-response/pjm-hot-days-report-july-16-18-2012.ashx.

102 Load Response Activity Report, August 2012, available at http://pjm.com/markets-and-operations/demand-response/~/media/markets-ops/dsr/2012-dsr-activity-report-20120810.ashx.

103 NYISO-Called Events & Tests, August 2, 2012, available at http://www.nyiso.com/public/webdocs/products/demand_response/general_info/Historic_EDRP_and_SCR_Activation_Information.pdf.

104 NYPA press release, June 20, 2012, available at http://www.nypa.gov/NYPAPressCenter/PressRelease/News/Hot%20Weather%20Leads%20to%20NYPAs%20Activation%20of%20Demand%20Response%20Program%20to%20Lower%20Electricity%20Use%20in%20NYC.html.

resources on July 17.[105] NYISO did not report any large demand response deployments during August.

In contrast to the Mid-Atlantic region, operators in the Midwest and New England primarily met summer heat wave loads through non-demand resources. For example, the Midwest ISO declared an emergency event on July 17 (which gave the Midwest ISO the option to utilize emergency demand response resources), but wind generation unexpectedly increased by about 200 MW shortly afterwards. As a result of this increase in supply, combined with changing weather conditions and voluntary conservation efforts, the Midwest ISO did not have to turn to emergency demand response resources.[106] ISO New England also did not report calling on demand response resources from June to August 2012, although the ISO called upon Real-Time Price Response Loads several times in late May.[107]

While the California ISO (CAISO) did not have any demand response deployments during summer 2012, the ISO did issue several Flex Alerts in August 2012. Flex Alert is a CAISO program that encourages California consumers to voluntarily conserve electricity and shift demand to off-peak hours when the ISO issues an alert. CAISO reports that its Flex Alert program led to significant voluntary reductions. For example, CAISO estimates that a Flex Alert issued on August 10 resulted in nearly 1,000 MW in load reductions. PG&E, one of the three large investor-owned utilities in California, estimates that over half of these reductions came from PG&E's voluntary demand response programs.[108]

Selected State Activities

State-regulated demand response activities over the past year have primarily focused on evaluating applications for large-scale rollouts of new time-based electricity pricing programs. States such as Arizona, California, and Maryland, as well as Arkansas, Oklahoma, Illinois, Idaho, Colorado, and Connecticut, have examined the issue of time-based rates, and many customers in these states are having their first experiences with these time-varying rates. The following section details developments in program rollouts in these nine states, and provides a spotlight on retail demand response programs in Texas.

Time-Based Pricing

Time-based pricing programs provide customers with economic incentives to shift consumption away from periods of increased demand,[109] giving an opportunity to save energy expenditures. In addition, shifts in consumption may reduce the need to construct

[105] NYISO-Called Events & Tests, August 2, 2012, available at http://www.nyiso.com/public/webdocs/products/demand_response/general_info/Historic_EDRP_and_SCR_Activation_Information.pdf.

[106] Summer Heat Wave, MISO Market Subcommittee Presentation, August 7, 2012, available at https://www.midwestiso.org/Library/Repository/Meeting%20Material/Stakeholder/MSC/2012/20120807/20120807%20MSC%20Item%2002b%202012%20Summer%20Heat%20Wave.pdf.

[107] See http://www.iso-ne.com/calendar/month.action?date=20120501&cats=18,19,20&type=2&link=yes&filter=off

[108] PG&E press release, available at http://www.pgecurrents.com/2012/08/17/pge-customers-heed-the-call-to-conserve/.

[109] Incentives include actual incurred electricity prices, a pre-specified incentive payment, or the customer's response to an emergency alert.

new power plants to meet increasing peak demand periods. Time-based pricing programs include a range of rate structures, such as critical peak pricing, critical peak rebates, real-time pricing, and variable peak pricing. A number of states and utilities took actions to implement time-based pricing programs in the past year. The Energy Information Administration (EIA) reports that twenty-nine states have adopted time-based pricing requirements, have requirements pending, or are studying these rate structures.[110]

In Arizona, an estimated one-third of the residential customers of Arizona Public Service and Salt River Project have voluntarily chosen to participate in one of their utility's time-of-use programs.[111] Both Arizona Public Service and Salt River Project offer web portals with user-friendly language to assist customers in making rate decisions, and offer features that allow residential customers to compare their rate options so that interested customers may choose the most cost-efficient rate program.[112] Arizona Public Service provides graphical comparisons of amounts paid under each available rate,[113] and Salt River Project provides customers with a web-based interactive tool that asks a series of questions so customers can choose a plan that fits their lifestyles.[114]

California is another state facilitating customer participation in dynamic pricing programs: all three investor-owned utilities in California plan to offer a dynamic pricing option to all customers by the end of 2012.[115] The California investor-owned utilities have had default time-of-use and critical peak pricing rates for their large commercial and industrial customers for several years, and while a law referred to as Senate Bill 645 currently prevents defaulting residential customers to these rates, efforts are being made to expedite the transition of residential customers to dynamic pricing plans "subject to resolution of pending proceedings and legal resolution of SB 695 provisions."[116] The California Public Utilities Commission

[110] EIA, Table 3 Existing or Pending Legislative or Regulatory Activity for Demand Response, available at http://www.eia.gov/analysis/studies/electricity/pdf/smartggrid.pdf.

[111] King, Chris, "Why energy consumers love VOLUNTARY dynamic pricing," eMeter: Smart Grid Watch, March 18, 2011, available at http://www.emeter.com/smart-grid-watch/2011/why-energy-consumers-love-voluntary-dynamic-pricing/.

[112] *See:* APS, Residential Rate Comparison, available at https://www.aps.com/main/services/demos/RateComparisonAudio.htm; SPR, Choose your price plan & save on electric bills, available at http://www.srpnet.com/prices/home/ChooseYourPricePlan.aspx.

[113] Ibid

[114] Schwartz, Judith, "Salt River Project: The Persistence of Choice," A National Town Meeting on Demand Response and Smart Grid, ADS Conference Presentation, June 28, 2012, available at http://www.demandresponsetownmeeting.com/presentations/.

[115] California Public Utilities Commission, Public Utilities Code Section 748 Report to the Governor and Legislature on Actions to Limit Utility Cost and Rate Increases, May 2012, available at http://www.cpuc.ca.gov/NR/rdonlyres/339C0DD6-0298-4BC7-AAD9-A27779AA43D4/0/2012SB695ReporttoGovernorandLegislatureFinalv2.pdf.

[116] For example, see California Public Utilities Commission, Proceeding A.10-08-005: Application of Pacific Gas and Electric Company for Approval to Defer Consideration of Default Residential Time-Variant Pricing until Its Next General Rate Case Phase 2 Proceeding, or in the Alternative for Approval of its Proposal for Default Residential Time-Variant Pricing and For Recovery of Incremental Expenditures Required for Implementation (U39E), available at http://delaps1.cpuc.ca.gov/CPUCProceedingLookup/f?p=401:1:392034754001701::NO:RP:: Proceeding A.10-07-009: In the Matter of the Application of San Diego Gas & Electric Company (U902E) for Approval of its Proposals for Dynamic Pricing and Recovery of Incremental Expenditures Required for Implementation; available at http://delaps1.cpuc.ca.gov/CPUCProceedingLookup/f?p=401:1:1372938263824701::NO:RP: Proceeding A.11-06-007: Application of Southern California Edison Company (U338E) To Establish Marginal

recently authorized portions of the investor-owned utilities' programs' dynamic pricing requests for 2012 through 2014 as part of the utilities' demand response programs and budget proposals.[117]

Maryland is also active in implementing dynamic pricing programs. The Maryland Public Service Commission approved applications from Baltimore Gas and Electric and Potomac Electric Power Company to offer peak time rebate programs. The Baltimore Gas and Electric program was approved for rollout in June 2013, while Potomac Electric Power Company planned to offer its program to over 5,000 customers in July 2012.[118] Both programs will be available on an opt-in basis to customers who have advanced meters installed.

Several other states also examined and approved dynamic pricing programs and rates. These include:

- **Arkansas and Oklahoma.** The Arkansas Public Service Commission and the Oklahoma Corporation Commission have each allowed the Oklahoma Gas and Electric Company to offer residential customers variable peak pricing rates on an opt-in basis.[119, 120]
- **Illinois.** In Illinois, both Ameren Utilities and Commonwealth Edison Company have received approval from the Illinois Commerce Commission to establish residential real-time pricing programs.[121]
- **Idaho.** The Idaho Public Utilities Commission approved a voluntary Idaho Power dynamic pricing program, initially proposed for 1,200 customers. After Idaho Power submits a report on its 2012 results, the program may be expanded to additional customers in 2013.[122]

Costs, Allocate Revenues, Design Rates, and Implement Additional Dynamic Pricing Rates, available at http://delaps1.cpuc.ca.gov/CPUCProceedingLookup/f?p=401:1:1372938263824701::NO:RP:.

[117] The decision authorized thee-year budgets of approximately $191.9 million for PG&E, $196.3 million for SCE and $65.8 million for SDG&E.

[118] Maryland Public Service Commission, In the Matter of Baltimore Gas and Electric Company for Authorization to Deploy a Smart Grid Initiative and To Establish a Surcharge for the Recovery of Cost, Case No. 9208, Order No. 84925, Item 143, Issued May 24, 2012, available at: http://webapp.psc.state.md.us/Intranet/home.cfm; and Maryland Public Service Commission, In the Matter of Potomac Electric Power Company and Delmarva Power and Light Company Request for the Deployment of Advanced Metering Infrastructure, Case No. 9207, Item 207, Order No. 84966, Issued June 8, 2012, available at: http://webapp.psc.state.md.us/Intranet/home.cfm.

[119] Oklahoma Corporation Commission, Standard Pricing Schedule: R-VPP Residential Variable Peak Pricing Program, Docket No. PUD 201000016, Order No. 575500, Approved May 2010, available at http://www.oge.com/Documents/OK/3.50%20R-VPP.pdf.

[120] Arkansas Public Service Commission, Oklahoma Gas and Electric Company Residential Variable Peak Pricing, Docket No. 10-067-U. Order No. 6, Approved June 2011, available at http://www.oge.com/Documents/ARK/2011%20Arkansas%20Docket%2010-067-U/R-VPP%206-6-2011.pdf.

[121] Illinois Commerce Commission, Real Time Pricing, available at http://www.icc.illinois.gov/Electricity/RTP.aspx.

[122] Idaho Public Utilities Commission, Case No. IPC-E-12-05: In the Matter of the Application of Idaho Power Company for Approval of Modifications to Schedules 1, 4, and 5 Implementing a Time Variant Pricing Plan,

- **Colorado.** In April 2011, the Colorado Public Utilities Commission (CPUC) closed a docket on exploring the issues related to smart grid and advanced metering by issuing a decision that included conclusions and next steps for the state.[123] In this document, the CPUC noted that one of the primary benefits of advanced meters is to provide a platform for dynamic pricing.
- **Connecticut.** In Connecticut, all electric distribution companies must offer voluntary critical peak pricing or real-time pricing programs for all customer classes.[124] As a result, the Connecticut Public Utilities Regulatory Authority has approved variable peak pricing rates for customers of both the Connecticut Light and Power Company[125] and the United Illuminating Company.[126]

Texas Retail Demand Response

The Public Utility Commission of Texas has developed a process to integrate the deployment of advanced metering with competitive demand response retail service markets. After an electric utility installs an advanced meter, residential customers in Texas have the option to choose demand response services and compatible technologies from a number of competing companies. Eligible demand response service providers include both retail energy providers and vendors of third-party products and services.[127] Third-party providers that participate in Texas' program have noted that they must engage and educate consumers on the benefits of demand response technology.

The Public Utility Commission of Texas, ERCOT, and interested stakeholders are also working on reducing barriers to increased demand response participation among advanced metering customers.[128,129] Through a series of workshops, stakeholders are examining a

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Order No 32499, March 27, 2012, available at:
http://www.puc.idaho.gov/orders/recent/Final_Order_No_32499.pdf.

[123] Colorado Public Utilities Commission, In the Matter of the Investigation of the Issues Related to Smart Grid and Advanced Metering Technologies: Order Stating Conclusions and Next Steps, Adopted March 2011, available at https://www.dora.state.co.us/pls/efi/EFI_Search_UI.Show_Decision?p_session_id=&p_dec=13836.

[124] *See:* Connecticut Public Utilities Regulatory Authority, Docket No. 03-07-02RE11: Application of the Connecticut Light and Power Company to Amend its Rate Schedule – Review of VPP Tariffs, September 21, 2011 Decision, available at
http://www.dpuc.state.ct.us/dockhist.nsf/8e6fc37a54110e3e852576190052b64d/d72d04fcf84696c185257958005bd05a?OpenDocument.

[125] Ibid.

[126] Connecticut Public Utilities Regulatory Authority, Docket No. 05-06-04RE04: Application of The United Illuminating Company To Increase Its Rates and Charges, – Public Act 07-242, Seasonal Rates, Non Generation-Related Time-of-Use Pricing and Related Rate Design Issues, September 28, 2008, Final Decision, available at
http://www.dpuc.state.ct.us/dockhist.nsf/8e6fc37a54110e3e852576190052b64d/17989d79124999ea8525752300524e43?OpenDocument.

[127] *See:* ERCOT, Demand Side Working Group (DSWG), AMI's Next Frontier Workshop, Agenda Item #6:Technology/Product Providers Perspectives, August 30, 2011, available at
http://ercot.com/calendar/2011/08/20110830-DSWG.

[128] ERCOT, Demand Side Working Group (DSWG), AMIT-DSWG Workshop, 'AMI's Next Frontier: Demand Response Part 2', December 16, 2011, available at http://ercot.com/calendar/2011/12/20111216-DSWG.

broad variety of potential barriers, including (1) the short duration of retail contracts (e.g., 12 or 24 months) that may not allow retail demand response providers to recover product and service costs, (2) the lack of regulatory requirements for retail energy providers to offer specific products, (3) limited third-party access to data, and (4) the reliability of communication networks.

Barriers to Demand Response

Demand-response can be accomplished through a variety of means and ways. As evidenced by the activities described above, the federal government, the Commission, and state and local governments have made progress on removing barriers to customer participation in demand response. Nevertheless, and depending on the type of demand-response to be pursued, several outstanding barriers remain.

- **Limited Number of Retail Customers on Time-Based Rates.** Previous Commission staff annual reports highlighted the low number of retail customers who purchase electricity based on time-based rates. While there is progress, without an expanded implementation of time-based rates across the U.S., the development of new technologies and programs and the fulfillment of the nation's demand response potential may be slowed.
- **Measurement and Cost-Effectiveness of Reductions**. While the lack of consistency in the measurement and verification of demand reductions and the lack of demand responsive-specific cost-effectiveness tools remain as barriers, significant progress to reduce these barriers occurred in the past year. NAESB completed some work on measurement and verification and the Commission issued a Notice of Proposed Rulemaking in April proposing to adopt the Phase II wholesale demand response measurement and verification standards. Furthermore, changes to the measurement and verification of demand response in organized wholesale energy and ancillary markets indicate movement toward more consistency across the various RTOs. Finally, focused review of these two issues is occurring within the National Forum on the National Action Plan on Demand Response.
- **Lack of Uniform Standards for Communicating Demand Response Pricing, Signals and Usage Information.** Communications to and interactions with demand response resources and end-use devices are typically based on company- and technology-specific proprietary protocols and techniques. The lack of common information models and protocols resulted in the potential for duplicative systems and inefficient transfer of pricing and usage information between parties. As discussed in **Chapter 4**, recent standards development work being led by the National Institute of Standards and Technology and the Smart Grid Interoperability Panel should help remove this barrier, if industry embraces and utilities these standards.
- **Lack of Customer Engagement.** Customers need to be effectively educated and informed about demand response and smart grid opportunities. Effective outreach

[129] Public Utility Commission of Texas, PUCT Project 34610: Implementation Project Relating to Advanced Metering, available at http://www.puc.state.tx.us/industry/projects/electric/34610/34610.aspx.

and communication are needed to explain demand response, time-based pricing and smart grid investments and the impacts of these at the customer level. Otherwise, customers may respond negatively to actions taken by their electric providers, e.g., the deployment of advanced meters. As the experiences of Oklahoma Gas and Electric and Arizona Public Service demonstrate, successful customer engagement efforts can be used to support smart grid investments, thereby promoting customer support. The efforts of the Smart Grid Consumer Collaborative to draw upon best practices may prove helpful.[130]

- **Lack of Demand Response Forecasting and Estimation Tools**. As the National Action Plan on Demand Response identified, "new tools and methods should be developed to directly incorporate demand response into dispatch algorithms and resource planning models," and "to forecast and model the capability of demand resources to adjust consumption in near real-time."[131] Current planning and forecasting tools are not sufficiently robust to model adequately the capability of demand response to serve as an alternative to building new generation and transmission and to act as a resource to alleviate transmission congestion. The efforts sponsored by U.S. Department of Energy to develop interconnection-wide plans that include demand side resources may help address this need. In addition, the National Forum on the National Action Plan on Demand Response is examining other modeling needs. The National Forum effort is inventorying existing demand response tools and models, and is identifying needed modeling and tools.

[130] Consumer engagement is a key topic for the Smart Grid Consumer Collaborative (SGCC). See SGCC, Consumer Engagement, available at http://smartgridcc.org/category/consumer-engagement.
[131] FERC, *National Action Plan on Demand Response*, June 2010, pp. 75-76.

CHAPTER 4. SMART GRID DEVELOPMENTS SUPPORTING DEMAND RESPONSE

This chapter reports on two key smart grid developments that support the further development of demand response resources: (1) the development of new communications and demand response standards by the National Institute of Standards and Technology's Smart Grid Interoperability Panel, and (2) the Smart Grid Demonstration Program sponsored by the U.S. Department of Energy.

Demand Response-Related Smart Grid Standards Development

In Title XIII of the Energy Independence and Security Act of 2007 (EISA), Congress addressed the need for standards for communication and interoperability of the grid to enable, among other things, the incorporation of demand response and demand-side resources into grid operations.[132] EISA directed the National Institute of Standards and Technology (NIST) to coordinate the development of a framework to achieve interoperability of smart grid devices and systems, including protocols and model standards for information management.[133] In turn, NIST set up the Smart Grid Interoperability Panel (SGIP), a public-private consensus-based organization, to coordinate standards development with input from a broad range of smart grid stakeholders.[134]

In 2009, the Commission issued a Smart Grid Policy Statement that identified demand response as one of four key functional priorities for smart grid interoperability standards development.[135] In the Policy Statement, the Commission reiterated that demand response can play a important role in integrating variable sources of renewable generation, and in maintaining system security in constrained areas.[136] NIST agreed that demand response is a priority for interoperability standards development, and has devoted considerable resources to this effort.[137] The following section reviews the progress of the SGIP efforts.

Demand Response Activities within the NIST/SGIP Process

The NIST Framework and Roadmap for Smart Grid Interoperability, Release 2.0 states the following:

"…the SGIP focuses on two principal areas where value can be added:

- **Analysis** of cross-functional area applications. Such applications often require coordination between one or more technologies, and this coordination introduces

[132] Public Law No. 110-140, 121 Stat. 1492, 1783-84, codified at 15 U.S.C. 17381 *et seq*. (2007).
[133] EISA sec. 1305(a), codified at 15 U.S.C. 17385(a).
[134] NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 2.0, at page 142.
[135] Federal Energy Regulatory Commission, *Smart Grid Policy*, 128 FERC ¶ 61,060 (2009). The other three functional priorities are wide-area situational awareness, energy storage, and electric transportation. The Commission also identifies two cross-cutting priorities, namely cyber security and communication and coordination across inter-system interfaces.
[136] *Id*., at P 74.
[137] NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 1.0.

issues and requirements beyond the original scope of the technology or technologies.

- **Coordination** among all groups which must complement each other on the resolution of a gap or overlap in Smart Grid technologies.

The first of these focus areas, Analysis, is provided by the SGIP through the working group structure, primarily through the Domain Expert Working Groups. The second of these focus areas, Coordination, is provided by the SGIP through the origination and oversight of the Priority Action Plan (PAP) groups."[138]

NIST and the SGIP established the following Priority Action Plans for demand response. As the name suggests PAPs are created when the SGIP determines there is a need for interoperability coordination on some urgent issue."[139]

- Standardized demand response information and signals;
- Standardized energy usage information;
- Wholesale demand response communication protocols; and
- Facility-level communication standards.

A number of standards related to demand response have received supermajority support within the SGIP,[140] or have made major strides to develop new standards, as described in the following sections.

Standardized demand response information and signals

Recognizing the need for electricity providers to be able to communicate demand response and distributed energy resources signals (e.g., price, information on system conditions, and dispatch instructions) with each other and with customers, the SGIP sponsored several PAPs to develop common protocols for communicating (1) price information, (2) demand response signals, and (3) equipment status for demand response and distributed energy resources.[141] Two standards development organizations, the Organization for the Advancement of Structured Information Standards (OASIS) and NAESB, did much of the standards development work, in collaboration with the PAP working groups.

The OpenADR Alliance, a diverse group of utilities, independent system operators, regulators, demand response providers, and controls suppliers is currently testing various forms of the OpenADR 2.0 standard.

[138] *Supra* at page 143.
[139] *Id.*, at page 150.
[140] When smart grid standards are supported by a supermajority, they are included in SGIP's Catalog of Standards. The Catalog of Standards is a compendium of standards and practices considered to be relevant for the development and deployment of an interoperable Smart Grid, Information on the Catalog of Standards is available at http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/SGIPCatalogOfStandards.
[141] PAP 3 (Develop Common Specification for Price and Product Definition) facilitated the development of the OASIS Energy Market Information Exchange (eMIX) standard. PAP 4 (Develop Common Schedule Communication Mechanism for Energy Transactions) helped produce the OASIS WS-Calendar standard. PAP 9 (Standard Demand Response and Distributed Energy Resources Signals) facilitated the development of the OASIS Energy Interoperation standard and OpenADR 2.0. For more information on the SGIP PAP process, see http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/WebHome.

Standardized energy usage information

In recognition of the importance of energy usage information to the smart grid, and the lack of a common, standardized approach, the SGIP established PAP 10 (Standard Energy Usage Information). The associated working group had the mission to develop a standardized information model for energy usage and to develop business rules for authorizing access to this usage information. Without these efforts, software developers and utilities would each need to develop customized, one-off solutions. Much of the work for this PAP has been led by NAESB. The result of NAESB's work (the Energy Usage Information standard) has been included in the Catalog of Standards. NAESB has also developed an Energy Service Provider Interface (ESPI) that provides a way for Energy Usage Information to be shared, in a controlled manner to ensure confidentiality, between participants in the energy services markets.

The Green Button initiative is also based on the framework created by the NAESB Energy Usage Information and ESPI standards. As discussed in **Chapter 2**, Green Button is an industry-led effort to provide electricity customers with easy access to their energy usage data in a consumer-friendly and computer-friendly format. To further develop the Green Button effort, the SGIP recently approved the creation of a new PAP 20 (Green Button ESPI Evolution).

There were several national-scale efforts over the past two years that have focused on providing privacy protection for consumer energy usage information. The SGIP Cyber Security Working Group devoted an entire chapter of the NIST IR 7628[142] to privacy principles. NAESB has also developed a set of guidelines[143] with respect to customer data being shared between utilities and third-party service providers.

Wholesale demand response communication protocols

The SGIP recently formed the PAP 19 working group (Wholesale Demand Response Communication Protocol) to develop and enhance data exchange between RTOs and demand response aggregators, which may include utilities.[144] The new effort is not intended to compete with standards for communicating with end-use customers, but rather is designed to create a seamless transfer of information and signals from wholesale system operators to demand response aggregators and then to end-use customers.

The PAP 19 working group is in the process of identifying electricity market requirements and gaps within current standards frameworks (including but not limited to Energy Interoperation, OpenADR 2.0 and the IEC Common Information Modeling), to adequately address demand response wholesale market interfaces.[145]

[142] NISTIR 7628, Guidelines for Smart Grid Cyber Security: Vol. 2, Privacy and the Smart Grid, available at http://nist.gov/smartgrid/upload/nistir-7628_total.pdf.

[143] North American Energy Standards Board, REQ.22 Third Party Access to Smart Meter-Based Information (2011)

[144] PAP 19 began its deliberations in March 2012.

[145] PAP 19 developed a Wholesale Demand Response Communication Protocol that was out for comment in Autumn 2012. See http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/PAP19WholesaleDR for more information.

Facility-level standards

The standards discussed in the preceding sections focus on the interchange of information and data among parties and across domains, and are not directly focused on the transfer of information or communications at the facility level. To address facility-level communications, the SGIP created two additional PAPs focused on communication and information exchange within buildings and premises.

One PAP deals with the Smart Energy Profile, which originally was a proprietary protocol developed for residential end users by the Zigbee Alliance, a collaboration of vendors and utilities. The Smart Energy Profile has since changed into an open standard that is harmonized with several previously competing communications standards. A new version 2.0 that communicates with home area networks is expected to be published by the end of 2012. It however is not compatible with the older Smart Energy Profile 1.0 and successor versions already installed in many meters. This lack of compatibility has troubled state commissions in Texas and California. In response, the SGIP established PAP 18 to focus on the technical issues associated with migration and the coexistence of two Smart Energy Profile versions. PAP 18 succeeded in identifying best practices and means to allow continued use of Smart Energy Profile 1.x and transition towards the use of Smart Energy Profile 2.0.[146]

A second PAP (PAP 17) focuses on interoperability among building energy management systems for primarily commercial buildings, although the standard could also be used in industrial facilities and residences. The standard is being developed through a partnership between ASHRAE and NEMA. This standard enables communications of demand response signals from system operators and aggregators, through building energy management systems, to equipment within facilities. It also can allow communications about electrical loads within the facility back to the utility and other electrical service providers.

Smart Grid Demonstration Program

The Smart Grid Demonstration Program[147] operated by the U.S. Department of Energy aims to demonstrate how a suite of existing and emerging smart grid concepts can be innovatively applied and integrated to prove technical, operational, and business model feasibility. The goal of the program is to demonstrate new and more cost-effective smart grid technologies, tools, techniques, and system configurations that significantly improve on the ones commonly used today. This program is currently funding 16 smart grid regional demonstration projects and 16 energy storage projects.[148] Most of these support advanced metering or demand response programs.

The regional smart grid demonstration projects were selected to verify smart grid viability, quantify smart grid costs and benefits, and validate new smart grid business models at scales that can be readily replicated across the country. Of these 16 projects, the nine that employ

[146] A white paper on this transition received supermajority support within the SGIP and is available at http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/PAP18SEP1To2TransitionAndCoexistence.
[147] This program was authorized by the Energy Independence and Security Act of 2007, Section 1304, and amended by the Recovery Act.
[148] The total budget for the 32 projects is about $1.6 billion; the federal share is about $600 million.

demand response technologies or otherwise enhance demand response are described below.[149]

- **AEP's gridSMART Demonstration Project** demonstrates the ability to maximize distribution system efficiency and reliability, and consumer use of demand response programs to reduce energy consumption, peak demand costs, and fossil fuel emissions.

- **Battelle Memorial Institute's Pacific Northwest Smart Grid Demonstration Project** is a collaboration between utilities, universities, and technology partners across five states More than 20 types of responsive Smart Grid assets, including demand response, storage, and direct load control, will be tested across six regional and utility operational objectives at 15 unique distribution sites operated by 12 utilities.

- **Kansas City Power and Light's Green Impact Zone SmartGrid Demonstration** is built around a SmartSubstation with a local distributed control system that includes advanced generation, distribution, and customer technologies.

- **Long Island Power Authority's Long Island Smart Energy Corridor** will integrate advanced metering technology with automated substation and distribution systems to reduce peak demand and energy costs, while improving the ability to identify and respond to outages.

- **Los Angeles Department of Water and Power's Smart Grid Regional Demonstration** is a collaboration between a consortium of research institutions to develop new Smart Grid technologies, quantify costs and benefits, validate new models, and create prototypes to be adapted nationally. The project consists of four broad initiatives: demand response, electric vehicle integration, customer behavior, and cyber security.

- **National Rural Electric Cooperative Association's Enhanced Demand and Distribution Management Regional Demonstration** demonstrates Smart Grid technologies with 27 cooperatives in 11 states. The project will conduct studies in advanced volt/volt-ampere reactive for total demand; demand response; critical peak pricing; water heater and air conditioning load control; thermal storage; energy usage portal pilots; consumer in-home energy display pilots; AMI integration; distribution co-op meter data management system applications; and self-healing feeders for improved reliability.

- **NSTAR Electric and Gas Corporation's Automated Meter Reading-Based Dynamic Pricing** will enable residential dynamic pricing (time-of-use, critical peak rates, and peak time rebates) and two-way direct load control by capturing automated meter reading (AMR) data transmissions and communicating through existing customer-sited broadband connections in conjunction with home area networks.

[149] SmartGrid.gov, Smart Grid Demonstration Program, available at http://www.smartgrid.gov/recovery_act/overview/smart_grid_demonstration_program.

- **Pecan Street Project's Energy Internet Demonstration** is developing and implementing an Energy Internet in Austin, Texas. Smart Grid technologies include advanced metering, energy control gateways, advanced billing software, and smart thermostats, distributed generation, thermal storage, battery storage, and smart irrigation systems.

- **Southern California Edison Company's Irvine Smart Grid Demonstration** will deploy advanced Smart Grid technologies in an integrated system to be more reliable, secure, economic, efficient, safe, and environmentally friendly. The technology demonstrations will include three main areas: (1) Energy Smart Customer Devices; (2) Year 2020 Distribution System including distribution automation with looped circuit topology, advanced voltage/VAR control, advanced distribution equipment, smart metering, utility-scale storage, and dispatched renewable distributed generation; and (3) a Secure Energy Network to demonstrate end-to-end management of a complex high performance telecommunication system.

APPENDIX A: SECTION 1252 OF THE ENERGY POLICY ACT OF 2005

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 non-regulated 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 non-regulated 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 AND ABBREVIATIONS

AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading OR Automatic Meter Reading
ARRA	American Recovery and Reinvestment Act of 2009
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
kW	Kilowatt
ISO	Independent system operator
ISO-NE	Independent System Operator of New England
LMP	Locational Marginal Price
Midwest ISO	Midwest Independent Transmission System Operator
MRO	Midwest Reliability Organization
MW	Megawatt
MWh	Megawatt-hour
NAESB	North American Energy Standards Board
NERC	North American Electric Reliability Corporation
NIST	National Institute of Standards and Technology
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
RTO	Regional transmission organization
SERC	SERC Reliability Corporation
SGIG	Smart Grid Investment Grant
SGIP	Smart Grid Interoperability Panel
SPP	Southwest Power Pool, Inc.
TRE	Texas Regional Entity
WECC	Western Electricity Coordinating Council

Appendix C: Glossary

Note: The terms and definitions provided in this glossary were provided to survey respondents and are for the limited purpose of the survey.

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

Advanced Meters: Meters that measure and record usage data at hourly intervals or more frequently, and provide usage data to both consumers and energy companies at least once daily. Data are used for billing and other purposes. Advanced meters include basic hourly interval meters, meters with one-way communication, and real-time meters with built-in two-way communication capable of recording and transmitting instantaneous data.

Aggregator: See "**Curtailment Service Provider**"

Ancillary Services: Services that ensure reliability and support the transmission of electricity to customer loads. Such services may include: energy imbalance, operating reserves, contingency reserves, spinning (also known as synchronized, ten-minute spinning, responsive) reserves, supplemental (also known as non-spinning, non-synchronized, ten-minute non-synchronous, thirty-minute operating) reserves, reactive supply and voltage control, and regulation and frequency response (also known as regulation reserves, regulation service, up-regulation and down-regulation).

Bid Limit: The maximum bid, in $/MWh, that can be submitted by a demand response program participant. If there is no bid limit, leave blank.

Capacity (program type): Displacement or augmentation of generation for planning and/or operating resource adequacy; penalties are assessed for nonperformance.

Capacity Market Programs: Arrangements in which customers offer load reductions as system capacity to replace conventional generation or delivery resources. Participating customers typically receive notice of events requiring a load reduction and face penalties when failing to curtail load. Incentives usually consist of up-front reservation payments.

Capacity Service: A type of demand response service in which **demand resources** are obligated over a defined period of time to be an available resource for the system operator.

Commercial and Industrial: Belonging to either of the energy-consuming sectors that consist of (a) a broad range of facility types including office buildings, retail establishments, hospitals, universities, the facilities of federal, state, and local governments and non-profit organizations, institutional living quarters, master-metered apartment buildings, and homes on military bases; and (b) manufacturing facilities and equipment used for producing, processing, or assembling goods and encompassing the following types of activities: manufacturing; processing; agriculture, forestry and fisheries; mining; and construction. Also, a business labeled as "industrial" by the North American Industry Classification

System or by the energy provider on the basis of energy demand or annual usage exceeding some specified limit set by the energy provider.

Coincident Reduction Capability: The amount of demand response curtailments that would be realized if all demand response products were called simultaneously and all responded by curtailing load at prearranged levels or at their enrolled quantity.

Critical Peak Pricing with Load Control: Demand-side management that combines direct load control with a pre-specified high price for use during designated critical peak periods, triggered by system contingencies or high wholesale market prices.

Critical Peak Pricing: Rate and/or price structure designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies by imposing a pre-specified high rate or price for a limited number of days or hours.

Curtailment Service Provider: Businesses that sponsor demand response programs that recruit and contract with end users, and sell the aggregated demand response to utilities, RTOs and ISOs. A Curtailment Service Provider is sometimes called an Aggregator and is not necessarily a load-serving entity.

Customer Sector: A group of customers: **residential, commercial and industrial**, and **other** (for example, **transportation**, **agricultural**).

Demand Bidding & Buy-Back: A program which allows a demand resource in retail and wholesale markets to offer load reductions at a price, or to identify how much load it is willing to curtail at a specific price.

Demand Resource or Demand-Side Resource: An electricity consumer that can decrease its power consumption in response to a price signal or direction from a system operator.

Demand Response: Changes in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity, 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 Program: A company's service/program/tariff related to demand response, or the change in customer electric usage from normal consumption patterns in response to changes in the price of electricity over time or in response to incentive payments designed to induce lower electricity use at times of high wholesale market prices, or a change in electric usage by end-use customers at the direction of a system operator or an automated preprogrammed control system when system reliability is jeopardized. Includes both time-based rate programs and incentive-based programs.

Demand Response Program/Tariff and Program/Tariff Types: A company or utility's service/product/compilation of all effective rate schedules, general terms and conditions and standard forms related to demand response and/or AMI services and classification thereof.

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. Also known as direct control load management.

Display Unit/In-home Display: Customer on-site device that receives (from a service provider or from a smart meter) and displays for the customer information such as usage and pricing data, messages, and alerts.

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

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

Electric Utility: A corporation, person, agency, authority, or other legal entity or instrumentality producing, transmitting, or distributing electricity for use primarily by the public. This includes: investor-owned electric utilities, municipal and state utilities, federal electric utilities, and rural electric cooperatives. A few entities that are tariff based and affiliated with companies owning distribution facilities are also included in this definition.

Emergency Event: An abnormal system condition (for example, system constraints and local capacity constraints) that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System.

Emergency Demand Response Event: The period of time during which participants in a Demand Response Program must reduce load. The Emergency Demand Response Event is announced by the program sponsor in response to an Emergency Event declared by it or by another entity such as a utility or RTO/ISO. Demand Response Program sponsors, utilities and RTO/ISOs typically declare these emergency events.

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

End-Use Customer: A firm or individual that purchases electricity for its own consumption and not for resale; an ultimate consumer of electricity.

Energy Payment for MWh Curtailed ($/MWh): Compensation paid or received for reductions in electric energy consumption.

Energy Service Providers: See **Power Marketers**.

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

Entity ID Number: The respondent should enter the ID number which appears on the survey transmittal e-mail, or the ID number used for the entity's response to the Form EIA-861 Survey.

Event Limits: The maximum number of times a demand response resource may be called during a specified period of time (typically one year or one season).

Federal Electric Utility: A utility that is either owned or financed by the Federal Government.

Generation and Transmission Company (G&T Company): A company that provides both energy production and facilities for transmitting energy to wholesale customers. G&T companies are usually formed by rural electric cooperatives and electric utilities to pool the costs and risks of constructing and managing the generation facilities and high-voltage transmission infrastructure which are needed to deliver energy to their customers.

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

In-home Display: See **Display Unit/In-home Display**.

Industrial Sector: The energy-consuming sector that consists of manufacturing facilities and equipment used for producing, processing, or assembling goods. The Industrial Sector encompasses the following types of activities: manufacturing; processing; agriculture, forestry and fisheries; mining; and construction. The term Industrial Sector may also designate a business labeled as "industrial" by the North American Industry Classification System or by the energy provider on the basis of energy demand or annual usage exceeding some specified limit set by the energy provider. See **Commercial and Industrial** sector.

Internet: The worldwide, publicly accessible series of interconnected computer networks that transmit data by packet switching using the standard Internet Protocol.

Interruptible Load: Electric consumption subject to curtailment or interruption under tariffs or contracts that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. In some instances, the demand reduction may be effected by action of the System Operator (remote tripping) after notice to the customer in accordance with contractual provisions.

Interval: The period of time for which advanced meters measure energy usage (and possibly other data). Increments are typically in minutes, and may consist of five-minute intervals, 15-minute intervals, or hourly intervals.

Interval Meter: An electric meter that measures energy use in increments of one hour or less.

Interval Usage: The amount of energy, measured in kWh, consumed during a period of time, typically five minutes, 15 minutes, or an hour.

Investor-Owned Electric Utility: A privately-owned electric utility whose stock is publicly traded. It is rate regulated and authorized to achieve an allowed rate of return.

Joint Action Agency: A body consisting of utility companies, municipalities who own public utilities, and/or municipalities who purchase energy from private utilities, which acts as a committee for making decisions regarding the acquisition and delivery of energy resources or related services.

Load as a Capacity Resource: Demand-side resources that commit to make pre-specified load reductions when system contingencies arise.

Load Serving Entity: Entities that provide electric service to end-users, wholesale customers, or both.

Mandatory Participation: Participation in the demand response program is required based on the customer's size or rate class. Customers are not offered the option of refusing to respond to requests for load reduction.

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

Maximum Demand of Customers: The highest level of total demand, in MW, for customers participating in a demand response program, excluding any demand reduction that results from the program. The maximum non-coincident demand of the participating customers that would occur without the program.

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.

Megawatt (MW): One thousand kilowatts or one million watts of electric power.

Megawatt-hour (MWh): One thousand kilowatt-hours or one million watt-hours of electric energy.

Member Company: Member of a joint action agency or generation and transmission company that supplies wholesale electricity and energy services.

Minimum Payment Rate: The smallest amount of money, in dollars per megawatt-hour, that a program sponsor will pay a demand response program participant for reduced energy consumption.

Minimum Reduction: A level established by the demand response program sponsor as the least amount of demand reduction, in megawatts, 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 shortest period of time that customers are obligated to participate in a demand response program.

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

NERC Regional Entity: One of the eight groups listed below (formerly known as Reliability Councils) organized within the major interconnections in the North American bulk power system. They work with the North American Electric Reliability Corporation to improve the reliability of the bulk power system. Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), Reliability*First* Corporation (RFC), SERC Reliability Corporation (SERC), Southwest Power Pool RE (SPP), Texas Regional Entity (TRE), Western Electricity Coordinating Council (WECC). The states of Alaska and Hawaii are not within a NERC Regional Entity, but for purposes of this survey appear as a choice in NERC Regional Entity fields.

Non-Spinning Reserves: Demand-side resource that may not be immediately available, but may provide solutions for energy supply and demand imbalance after a delay of ten minutes or more.

Opt-In: A Time-Based Rate/Tariff or demand response program in which a customer will be enrolled only if the customer chooses to enroll.

Opt-Out: A Time-Based Rate/Tariff or demand response program in which a customer will be enrolled unless the customer chooses not to enroll; a program that is the default for a class of customers but that allows individual customers to choose an alternative rate/tariff or program.

Other (as shown in Q3, Q5 & Q6): Customers who are in a customer class that is not listed.

Other Demand Response Program/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 that are not **Residential, Commercial and Industrial,** or **Other**.

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

Penalties: Fines or reductions in payments that result when a demand response program participant fails to meet targeted reductions in power demand or chooses to not reduce consumption during a demand response event.

Potential Peak Reduction: The sum of the load reduction capabilities (measured in megawatts) of the demand response program participants, within the specified customer sector, whether reductions are made through the direct control of the utility system operator or by the participant in response to price signals or a utility request to curtail load. It reflects the demand reduction capability, as opposed to the actual peak reduction achieved by participants.

Power Marketers: Business entities, including energy service providers, which are engaged in buying and selling electricity, but which do not necessarily own generating or transmission facilities. Power marketers and energy service providers take ownership (title) of the electricity, unlike power brokers, who do not take title to electricity. Power marketers are involved in interstate commerce and must file with the FERC for authority to make wholesale sales. Energy service providers will not file with the FERC but may file with the states if they undertake only retail transactions.

Program Type: The category of demand response arrangements between retail or wholesale entities and their retail or wholesale customers. Examples of these arrangements include*:* critical peak pricing, critical peak pricing with load control, direct load control, interruptible load, load as a capacity resource, regulation, non-spinning reserves, spinning reserves, demand bidding and buy-back, time of use pricing, real-time pricing, system peak response transmission tariff, peak time rebate, and emergency demand response, all of which are defined in this glossary.

Program End Date: A date specified when the demand response and/or time-based rate program is no longer in effect.

Program Start Date: A date specified when a demand response and/or time-based rate program began.

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

Publicly Owned Electric Utility: Utilities operated by municipalities, political subdivisions, and state and federal power agencies (such as the Bonneville Power Administration and the Tennessee Valley Authority).

Realized Demand Reduction: The largest hourly demand reduction (in megawatts) that occurred when the demand response program was called, or that was attributable to the demand response program, during the 2011 calendar year.

Real Time Meters: Meters that measure energy as used, with built-in two-way communication capable of recording and transmitting instantaneous data.

Real Time Pricing: Rate and price structure in which the retail price for electricity typically fluctuates hourly or more often, to reflect changes in the wholesale price of electricity on either a day-ahead or hour-ahead basis.

Regulation Service: A type of Demand Response service in which a Demand Resource increases and decreases load in response to real-time signals from the system operator. Demand Resources providing Regulation Service are subject to dispatch continuously during a commitment period. This service is usually responsive to Automatic Generation Control (AGC) to provide normal regulating margin. Also known as regulation or regulating reserves, up-regulation and down-regulation.

Reliability: A measure of the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.

Reliability Event: An event, such as the loss of a line or generator, or imbalance between supply and demand, which threatens the safe operation of the grid.

Reserve: A service in which demand resources are obligated to be available to provide demand reduction upon deployment by the system operator, based on reserve capacity requirements that are established to meet reliability standards.

Residential: The energy-consuming sector consisting of private households. Common uses of energy associated with this sector include space heating, water heating, air conditioning, lighting, refrigeration, cooking, and running a variety of other electric-powered devices. The residential sector excludes institutional living quarters. This sector excludes deliveries or sales to master-metered apartment buildings or homes on military bases (these buildings or homes are included in the commercial sector).

Response Time: The maximum time allowed in a demand response program for a program participant to react to the program sponsor's notification, in hours.

Retail: Sales covering electrical energy supplied for residential, commercial, industrial, and other (e.g., agricultural) end-use purposes. Electricity supplied at retail cannot be offered for resale.

Retail Customer: A purchaser of energy that consumes electricity for residential, commercial, or industrial use, or a variety of other end-uses.

Retail Electric Customer: See Retail Customer.

Rural Electric Cooperative: A member-owned electric utility company serving retail electricity customers. Electric cooperatives may be engaged in the generation, wholesale purchasing, transmission, and/or distribution of electric power to serve the demands of their members on a not-for-profit basis.

Specific Event Limits: The maximum number of times that a participant in a demand response program may be called to reduce energy consumption during a year.

Spinning/Responsive Reserves: Demand-side resource that is synchronized and ready to provide solutions for energy supply and demand imbalance within the first few minutes of an Emergency Event.

System Peak Response Transmission Tariff: The terms, conditions, and rates and/or prices for customers with interval meters who reduce load during peaks as a way of reducing transmission charges.

Tariff: A published volume of all effective rate schedules, terms and conditions under which a product or service will be supplied to customers.

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

Time-of-Use: A rate where usage unit prices vary by time period, and where the time periods are typically longer than one hour within a 24-hour day. Time-of-use rates reflect the average cost of generating and delivering power during those time periods.

Transportation: An energy consuming sector that consists of electricity supplied and services rendered to railroads and inter-urban 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. In this survey, transportation customers should be counted in the **Other** category.

Transportation Program/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 transportation customers.

Type of Entity: The category of organization that best represents the energy market participant. The available options include: investor-owned utility, municipal utility, cooperative utility, state-owned utility, federally-owned utility, independent system operator, retail power marketer, wholesale power marketer, regional transmission operator, curtailment service provider, transmission, or other.

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

Wholesale: Pertaining to a sale of electric energy for resale.

Wholesale Customer: An entity that purchases electric energy for resale.

APPENDIX D: 2012 FERC SURVEY METHOD

Background

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. Commission staff determined that a survey of a full set of private and public entities that provide electric power and could provide demand response to customers would help fulfill the requirement.

In the first half of 2012 Commission staff:

- Identified survey respondents, i.e., the "survey population;" and
- Developed a voluntary survey based on a PDF vehicle.

Beginning in February of 2012 Z, INC. and their subcontractor DNV KEMA

- Developed a sampling design based on the 2010 FERC Demand Response and Advanced Metering Survey;
- Revised a custom survey processing system in Microsoft Access to interface with the FERC provided PDF Survey;
- Reviewed the list of survey respondents and removed companies who are out business or do are not appropriate recipients of the survey[150];
- Distributed the 2012 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 originally requested from all 3,349 entities from all 50 states representing all aspects of the electricity delivery industry: investor-owned utilities, municipally owned utilities, wholesale and retail power marketers, state and federal agencies, and (rural electric) cooperatives. The 2012 FERC Survey respondent list was based on the list of entities that the Energy Information Administration (EIA) uses for their Form EIA-861 Survey Form. The FERC staff added three categories of respondents to the base set of EIA contacts – Regional Transmission Organizations (RTOs)/Independent System Operators (ISOs), curtailment service providers, and transmission companies.

During the survey processing period it was determined fifteen entities were no longer in operation or should not have received the survey. These entities were removed from the survey respondent list, resulting in a list of 3,334 active respondents. Out of this active group, 1,978 entities responded to the 2012 FERC Survey (a response rate of 59.3 percent), an increase from the 2010 FERC Survey response rate of 52 percent.

Development of the FERC Survey and Sampling Design

The 2012 FERC Survey was conducted subject to the same Office of Management and Budget (OMB) authorization that was provided to the Commission for similar surveys

[150] A surveyed company may have been acquired by another company, for example.

previously. The 2010 authorization of March 31, 2013 was used.[151] As was done in the previous three surveys, Commission staff fielded the survey on a voluntary rather than a mandatory basis. Commission staff designed the survey to collect the needed information using nine questions organized in three sections. The three sections include one parent section containing questions one through seven and two child sections covering retail and wholesale demand response programs:

Parent record (only one record per Utility)

Question 1: Company and contact information including utility ID, company name and ownership type. Primary contact information along with their supervisor's information.

Question 2: Advanced and total meter counts by State and customer class

Question 3: Number of retail customers and meters by NERC region and customer class. (optional, skip if there are demand response programs)

Question 4: Number of retail customers that can access the amount and frequency of their electricity use by method and by customer sector.

Question 5: Plans for demand response programs over next 5 years by number of programs and potential peak reduction.

Question 6: NERC regions and states in which you operate

Question 7: Number of retail customers for each NERC and State combination in Question 6,

by customer class.

Child 1 Record (Add additional pages as needed)

Question 8: Detailed retail demand response program information by NERC region, State, Customer class, and Program type.

Child 2 Record (Add additional pages as needed)

Question 9: Detailed wholesale demand response program information by NERC region, State, and Program type.

By shifting the detailed Demand Response program information to the end of the survey, the burden on small utilities without demand response programs was lessened because they were only asked to complete Questions 1 through 3. Also, by having all the information relative to one demand response program on one page (Child record), respondents could as many pages as required to cover each of their programs. The content of the 2012 FERC Survey mirrored

[151] Links to the 2012 FERC Survey documents can be found at http://www.ferc.gov/industries/electric/indus-act/demand-response/2012/survey.asp.

the 2010 FERC Survey collected. The structure of the survey was duplicative of the 2010 survey.

The Survey Population

To analyze the survey data and calculate statistics for this report, Commission staff reviewed the composition of the survey population, and found that there were 3,349 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.

Table D-1. Survey Population for the 2012 FERC Survey

Group Name	2012 N0.	2010 No.
Municipally Owned Utility	1,834	1,840
Cooperatively Owned Utility	874	878
Investor-Owned Utility	194	207
Retail Power Marketer	135	128
Wholesale Power Marketer	42	46
Political Subdivision	127	127
Municipal Power Agency	19	21
Federal and State	35	29
Regional Transmission Organization/ Independent System Operator	7	7
Curtailment Service Provider	11	11
Transmission	9	7
Total Classified	3,287	3,301
Unclassified	47	57
Active Total	3,334	3358
Inactive (removed from survey population)	15	96
Grand Total	3,349	3,454

FERC Survey Methodology

On March 23, 2012, the survey was distributed through a mass e-mailing. This message included an introduction to the survey as well as directions and the glossary (see **Appendix C**). The survey itself was attached to the e-mail. The survey form was in PDF format, programmed such that the respondents could respond directly on the PDF form. They then would e-mail their surveys to a main collecting point, an e-mail account set up specifically for the collection of the surveys. For any inquiries or questions the respondents might have, they could reach out to the FERC staff for help at DRSurvey@ferc.gov and DRSurvey-Help@ferc.gov.

Z, INC., in collaboration with the FERC staff, strove to maximize the response rate through various means. If respondents required specific information, a phone hotline was established, open daily between 9 am and 6 pm. FERC staff also initiated its own dissemination of the survey through postal mail, to capture any respondents that might not have internet access or a functional e-mail account. Additionally, Z, INC assisted in the sending out of a reminder e-mail to all those who had not responded as of April 25, 2012. Z, INC. also contacted all companies that were statistically significant (i.e., large companies and those selected for the sample), as well as all medium-sized companies, reaching more than 1,200 companies individually. Finally, FERC Chairman Jon Wellinghoff sent out a letter to all cooperating organizations, including members and representatives of the National Association of Regulatory Commissioners, American Public Power Association, Edison Electric Institute, and the National Rural Electric Cooperative Association, asking them to reach out to members and the industry to encourage submission of the survey.

As responses were returned to us, Z, INC. employed a rigorous system of verification and due diligence. Beyond the software used to collect the submissions to the e-mail account established by the FERC staff, Z, INC. also searched through the e-mail account looking for attachments that had not been included in the data upload or other related problems. Anomalies and seemingly incorrect information received a flag, indicating the necessity for personal follow-up.

Continuous efforts were also made to ensure the optimal structure and processing of the incoming data. Z, INC. created a specialized database for the 2010 FERC-731 Survey. This database included all available information for on each entity in the survey population, This data base allowed for a more efficient process overall, reducing the labor involved with cleaning data.

Working with the Data

As discussed in **Chapters 2** and **3**, the FERC staff used the 2012 FERC Survey to estimate advanced metering penetration rate and potential peak reduction. The following discussion describes the analysis undertaken by the FERC staff and Z, Inc.'s subcontractor DNV KEMA, who was responsible for the analysis.

Advanced Metering

The FERC staff developed estimates of the penetration rate of national and regional advanced metering required by Congress at the national, regional, and state levels, as well as by load serving entity type. These estimates were to reflect the full universe of entities in the United States that own electricity meters for retail. The FERC Survey population encompasses all such entities. As such, the primary data source of the estimates produced is the set of respondent data from the 2012 FERC Survey. Some entities in the FERC Survey did not respond, requiring statistical estimation of advanced metering penetration in their retail service territories so that the estimates account for the whole survey population.

The approach taken by DNV KEMA was to make statistically informed imputations of the number of customers, advanced meters, and total meters for non-responding entities leveraging related published information from the 2011 preliminary Form EIA-861 Survey and FERC Survey. The Form EIA-861 Survey file 2 contains customer counts at the entity level by customer class, which is highly correlated with total meter counts, a FERC Survey item. Other FERC Survey items – customer counts and advanced meters – have direct counterparts in the Form EIA-861 Survey. For the "other" customer class (i.e., retail customers not classified as residential, commercial, or industrial), there is not a comparable field in the Form EIA-861 Survey from which to link to the 2012 FERC Survey. For this customer class balance group, the 2010 FERC Survey was used as the source of missing data.[152]

When an entity did not respond to the 2012 FERC Survey at all, or responded but did not provide a valid entry for the number of advanced meters for a customer class, DNV KEMA used direct substitution of an entity's advanced meters by sector from the reported value by that entity in the 2011 Form EIA-861 Survey. Having the 2011 Form EIA-861 Survey preliminary database available for comparison was valuable because both surveys collected 2011 summary information. If the sector-level advanced meter count for an entity was not available in the preliminary 2011 Form EIA-861 Survey database made available to DNV KEMA for this analysis, the imputation methodology from the 2010 FERC Survey analysis was used, with updated databases supporting it.

Having access to the preliminary 2011 Form EIA-861 Survey database was valuable also because it contains fields for both advanced and AMR meters. DNV KEMA developed an editing procedure to identify instances where it appeared likely that the respondent was misreporting AMR meters as advanced meters in the 2012 FERC Survey.

The logic used in the editing procedure started with computing the percent difference in advanced meters between the 2012 FERC Survey and the 2011 Form EIA-861 Survey and the percent difference between the meters in the 2012 FERC Survey advanced metering and the Form EIA-861 Survey AMR meter count. If an entity did not provide an advanced meter count on the Form EIA-861 Survey but did provide a count for AMR meters, and the AMR meter count was within 50 percent of the reported advanced meter count on the 2012 FERC Survey, DNV KEMA edited the advanced metering value. The 2012 FERC survey was set to zero since the entity likely misreported an AMR meter count which does not meet the FERC definition of advanced metering.

If the entity reported meter counts for both AMI and AMR on the Form EIA-861 Survey, and the 2012 FERC Survey advanced meter count was found to be significantly closer to the sum of the AMR and AMI meter totals than just the AMI meters on the Form EIA-861, the determination was that the respondent likely included both AMI and AMR meters on the 2012 FERC Survey, when it should have only included AMI meters. In these instances, the Form EIA-861 total AMI meters were used in the analysis.

Demand Response

The FERC Survey responses were extrapolated to estimate the demand response for the entire FERC Survey population by imputing survey answers for nonrespondents using an

[152] A secondary data source field that is used directly or following a statistical modification, in place of a missing value on the FERC Survey, is referred to as a "donor variable".

imputation method that limits the bias introduced. The DNV KEMA approach for imputation utilized direct substitution of responses by the entity for comparable survey items (same survey year and identical or nearly identical wording and/or response categorization) from related surveys when such responses are available. When direct substitution was not available, responses from identical or closely related questions of past survey years were utilized, with a class-level growth rate multiplier applied. Classes were defined according to customer sector and size exactly as is documented in the 2010 report.

For potential peak reduction, the imputation process below was implemented for the tables supporting figures 4.12 and 4.13, which give estimated potential MW by entity type, NERC region, and customer sector.

If an entity did not provide potential peak reduction in the 2012 FERC Survey, data on potential peak reduction from the 2011 Form EIA-861 was used. However, since the Form EIA-861 data only contains potential peak reduction at the entity/sector level, but not by state or demand response program type, imputations were made at this entity/sector level, not at the state or program type level. If there was no response for potential peak reduction in the 2012 FERC survey response and an imputation was made with the EIA data, the potential peak reduction value was assigned to the entity's primary NERC region.

If an entity did not provide potential peak reduction either the 2012 FERC Survey or the 2011 Form EIA-861, but provided a response to the 2010 Form EIA-861 for this item, it was multiplied by a the class-level growth rate between 2010 and 2011 and used as the imputed value. If the customer sector for the demand response program was listed as "Other", and the entity did not provide potential peak reduction in the 2012 FERC Survey, the 2010 FERC Survey response value multiplied by a class-level growth rate factor was used as the imputed value. No imputation was used for wholesale potential peak reduction.

Eliminating Double-Counting in Wholesale Demand Response

The methodology used for tabulating wholesale potential peak reduction was designed to identify and separate potential peak reduction that is solely wholesale in nature and is not associated with any programs offered by retail entities (such as an investor-owned utility). If a retail entity reported that 50 MW of potential peak reduction was enrolled in an ISO or RTO wholesale market demand response program, the 50 MW may have also been included in the ISO or RTO's survey response. The 50 MW could be counted as both retail demand response, since it was reported by a retail entity in Q8, and as wholesale demand response, since it was reported by the ISO or RTO in its Q9 submission for wholesale entities. The 50 MW should be counted only once as either retail or wholesale. The FERC staff decision rule for this and each prior survey has been to count it as retail demand response.

To accomplish this, DNV KEMA merged the enrolled potential demand response reported by retail entities in Q8 with the Q9 reports by wholesale entities as negative values of the same magnitude. In principle, the tabulation of the combined values would give the final wholesale potential demand response. This, however, does not work because ISO/RTOs classify their demand response programs by purpose, such as load as a capacity resource or emergency demand response, while retail entities generally classify programs according to the mechanism employed for reducing load, such as an air conditioner or water heater direct load control program, or according to the contract agreement with a large commercial or industrial customer. To align the programs to reduce double counting, DNV KEMA reclassified the program type listed for retail entities to match the program type listed by the ISO or RTO market program that the retail program was enrolled in. Note that the retail program types were only recategorized in this step for the enrolled potential demand response for the purpose of eliminating double counting. The entity's response for potential peak reduction by sector was according to the original program type in their response.

Appendix E: FERC Survey Respondents

Appendix E lists the entities that responded to the 2012 FERC Survey, organized by entity type.

Cooperatively Owned Utility

4-County Electric Power Assn	MS
A & N Electric Cooperative	MD,VA
Adams Electric Cooperative	IL
Adams Electric Cooperative, Inc.	PA
Adams Rural Electric Cooperative, Inc.	OH
Adams-Columbia Electric Cooperative	WI
Alaska Village Elec. Coop. Inc.	AK
Albemarle Electric Member Corp.	NC
Alder Mutual Light Co., Inc.	WA
Alger-Delta Cooperative Electric Association	MI
Allamakee- Clayton El Coop, Inc	IA
Allegheny Electric Cooperative, Inc.	PA
Amicalola Electric Membership Corp	GA
Anza Electric Cooperative, Inc.	CA
Appalachian Electric Cooperative	TN
Arizona Electric Power Cooperative, Inc.	AZ
Arkansas Electric Cooperative Corporation	AR
Arkansas Valley Electric Cooperative Corporation	AR,OK
Ashley-Chicot Electric Cooperative, Incorporated	AR
Atchison-Holt Electric Coop	IA,MO
Bailey County Electric Cooperative	TX
BARC Electric Coop Inc	VA
Barron Electric Coop	WI
Barrow Utilities & Electric Coop., Inc.	AK
Barry Electric Cooperative	MO
Bartlett Electric Cooperative Inc	TX
Basin Electric Power Coop	ND
Bayfield Electric Cooperative	WI
Bedford Rural Elec Coop, Inc	PA
Beltrami Electric Cooperative, Inc	MN
Benton Rural Electric Association	WA
Big Bend Electric Cooperative, Inc	WA
Big Country Electric Cooperative, Inc.	TX
Big Flat Electric Co-op., Inc.	MT
Big Horn County Elec Coop, Inc	MT
Big River Electric Coop	KY
Black Hills Electric Cooperative, Inc	SD
Black River Electric Cooperative	MO
Blue Grass Energy Cooperative Corporation	KY
Blue Ridge Electric Coop Inc - (SC)	SC
Blue Ridge Mountain EMC - (GA)	GA
Bluebonnet Electric Cooperative Inc.	TX
Bon Homme Yankton Electric Association, Inc.	SD
Boone Valley Electric Coop	IA
Brazos Electric Power Cooperative, Inc.	TX
Broad River Electric Cooperative, Inc.	NC,SC
Brunswick Electric Membership Corporation	NC
Buckeye Power, Inc.	OH
Buckeye Rural Electric Cooperative, Inc.	OH
Butler County Rural Elec Coop - (IA)	IA
Butler Rural Electric Cooperative Association, Inc.	KS
Butler Rural Electric Cooperative, Inc.	OH
Butte Electric Cooperative	SD
C&L Electric Cooperative Corporation	AR
Caddo Electric Cooperative, Inc.	OK
Calhoun County Electric Cooperative Association	IA
Cam Wal Electric Cooperative, Inc	SD
Canadian Valley Electric Cooperative	OK
Caney Fork Electric Cooperative, Inc.	TN
Capital Electric Cooperative, Inc.	ND
Carbon Power & Light Inc	WY
Carroll County REMC	IN
Carroll Electric Cooperative Corporation	AR,MO
Carroll Electric Cooperative, Inc	OH
Carroll Electric Membership Corporation	GA
Carteret-Craven Electric Membership Corporation	NC
Cass County Electric Cooperative	ND
Cass Electric Cooperative	IA
Cavalier Rural Electric Coop, Inc.	ND
Central Alabama Electric Cooperative	AL
Central Electric Cooperative	SD
Central Electric Cooperative, Inc.	PA
Central Electric Power Cooperative	MO
Central Electric Power Cooperative, Inc.	SC
Central Georgia Electric Membership Corp.	GA
Central Iowa Power Cooperative	IA
Central Valley Electric Coop., Inc.	NM
Charles Mix Electric	SD
Cherryland Electric Coop Inc	MI
Chippewa Valley Electric Coop	WI
Choctawhatchee Electric Cooperative, Inc.	FL
Clark County REMC	IN
Clark Electric Coop	WI
Claverack REC	PA
Clay County Electric Cooperative Corporation	AR
Clay Electric Cooperative, Inc.	FL
Clay-Union Electric Corporation	SD
Clearwater Power Company	ID,OR,WA
Clearwater-Polk Electric Cooperative, Inc.	MN
Cloverland Electric Cooperative	MI
Coahoma electric Power Association	MS
Coastal Electric Cooperative	GA
Codington-Clark Electric Cooperative, Inc.	SD
Coles-Moultrie Electric Cooperative	IL
Colquitt Electric Membership Corporation	GA
Columbia Power Cooperative Association	OR
Concordia Electric Cooperative, Inc.	LA
Connexus Energy	MN
Consolidated Electric Cooperative	MO
Consumers Energy	IA
Consumers Power Inc.	OR
Cookson Hills Electric Cooperative	OK
Cooperative Light and Power	MN
Coosa Valley Electric Cooperative	AL
Coos-Curry Electric Cooperative, Inc.	OR
Cordva Electric Cooperative, Inc.	AK
Corn Belt Energy Corporation	IL
Corn Belt Power Cooperative	IA
Craig-Botetourt Electric Cooperative	VA,WV
Craighead Electric Cooperative Corporation	AR
Crow Wing Cooperative Power & Light Company	MN
Cumberland Electric Membership Corporation	TN
Dairyland Power Cooperative	IA,MN,WI

Cooperatively Owned Utility (Continued)

Dakota Electric Association	MN
Darke Rural Electric Coop, Inc	OH
Deep East Texas Electric Coop Inc	TX
Delaware Electric Cooperative, Inc.	DE
Dixie Electric Cooperative	AL
Dixie Electric Membership Corporation	LA
Dixie Electric Power Association	MS
Dixie Escalante REA Inc.	AZ,UT
Doniphan Elec Coop Assn, Inc	KS
Douglas Electric Cooperative, Inc	OR
Douglas Electric Cooperative, Inc.	SD
Dubois Rural Electric Cooperative, Inc.	IN
Duck River Electric Membership Corporation	TN
Dunn County Electric Cooperative	WI
East End Mutual Elec Co Ltd	ID
East River Electric Power Cooperative, Inc.	SD
East-Central Iowa Rural Electric Cooperative	IA
Eastern Maine Electric Cooperative, Inc	ME
Eau Claire Electric Coop	WI
Edgecombe-Martin County Electric Membership Corp.	NC
Edisto Electric, Cooperative, Inc.	SC
Egyptian Electric Cooperative Association	IL
Empire Electric Association, Inc.	CO
Energy United Electric Membership Corp	NC
Excelsior Electric Membership Corporation	GA
Fairfield Electric Cooperative Inc.	SC
Farmers Electric	ID
Farmers Electric Cooperative	TX
Farmers Electric Cooperative Corporation	AR
Farmers Electric Cooperative, Inc	IA
Farmers' Electric Cooperative, Inc.	MO
Farmers' Electric Cooperative, Inc.	NM
Federated Rural Electric	IA,MN
Fergus Electric Cooperative, Inc.	MT
First Electric Cooperative Corporation	AR
Flathead Electric Cooperative, Inc.	MT
Flint Electric Membership Corporation	GA
Florida Keys Electric Cooperative	FL
Four County EMC	NC
Fox Islands Electric Cooperative, Inc.	ME
Franklin Electric Cooperative	AL
Franklin Rural Electric Cooperative- (IA)	IA
Freeborn-Mower Coop Services	MN
French Broad Electric Membership Corporation	NC,TN
Fulton County REMC	IN
Gascosage Electric Cooperative	MO
Gibson Electric Membership Corporation	TN
Golden Spread Electric Cooperative, Inc.	TX
Goldenwest Electric Cooperative, Inc.	MT,ND
Graham County Electric Cooperative, Inc	AZ
Grundy County Rural Electric Coop	IA
Grundy Electric Cooperative, Inc.	MO
Guernsey-Muskingum Electric Cooperative, Inc.	OH
Habersham Electric Membership Corporation	GA
Halifax Electric Membership Corporation	NC,VA
Hart Electric Membership Corporation	GA
Hawkeye Tri-County El Coop Inc	IA
Haywood Electric membership Corp.	GA,NC,SC
H-D Electric Cooperative, Inc	MN,SD
Heart of Texas Electric Cooperative, Inc.	TX
Heartland Power Coop	IA
Heartland Rural Electric Cooperative Inc	KS
Hendricks County Rural Electric Membership	IN
Henry County REMC	IN
High Plains Power, Inc.	WY
Highline Electric Association	CO,NE
HILCO Electric Cooperative, Inc.	TX
Hill County Electric Cooperative, Inc.	MT
Holmes-Wayne Electric Cooperative, Inc.	OH
Holy Cross Electric Assn, Inc	CO
Hood River Electric Cooperative	OR
Houston County Electric Cooperative, Inc.	TX
Humboldt County R E C	IA
Idaho County Light & Power Cooperative Assoc., Inc.	ID
Illinois Rural Electric Cooperative	IL
Indian Electric Cooperative, Inc.	OK
Inter-County Energy Cooperative	KY
Intercounty Electric Cooperative Assn.	MO
Iowa Lakes Electric Coop	IA
Irwin Electric Membership Corp	GA
Itasca-Mantrap Cooperative Electrical Association	MN
J-A-C Electric Cooperative Inc	TX
Jackson County Rural electric Membership Corporation	IN
Jackson Electric Cooperative	WI
Jackson Electric Membership Corporation	GA
Jackson Energy Cooperative Corp - (KY)	KY
Jackson Purchase Energy Corporation	KY
Jasper County REMC	IN
Jasper-Newton Electric Cooperative	TX
Jefferson Energy Cooperative	GA
Jemez Mountains Electric Cooperative, Inc.	NM
Jo-Carroll Energy, Inc. (NFP)	IL
Jones-Onslow Electric Membership Corporation	NC
Jump River Electric Cooperative, Inc.	WI
KAMO Electric Cooperative, Inc	OK
Kankakee Valley Rural Electric Membership Corp	IN
Kansas Electric Power Cooperative, Inc.	KS
Kauai Island Utility Cooperative	HI
KC Electric Association, Inc.	CO
KEM Electric Cooperative, Inc.	ND
Kingsbury Electric Cooperative, Inc.	SD
Kodiak Electric Association, Inc.	AK
Kosciusko REMC	IN
La Plata Electric Assn. Inc.	CO
Laclede Electric Cooperative	MO
Lacreek Electric Association, Inc.	NE,SD
Lagrange County Rural E M C	IN
Lake Country Power	MN
Lake Region Electric Cooperative	MN
Lamb County Electric Cooperative	TX
Lane Electric Cooperative Inc	OR
Lee County Electric Cooperative, Incorporated	FL
Lewis County Rural Electric Coop Association	MO
Licking Valley RECC	KY
Lincoln Electric Cooperative	MT
Linn County Rural Electric Cooperative Association	IA

Cooperatively Owned Utility (Continued)

Los Alamos County	NM
Lower Yellowstone REA Inc.,	MT,ND
Lumbee River Electric Membership Corporation	NC
Lynches River Electric Cooperative, Inc.	SC
Lyntegar Electric Cooperative, Inc.	TX
Lyon-Coffey Electric Cooperative, Inc.	KS
M & A Electric Power Cooperative	MO
M.J.M. Electric Cooperative, Inc.	IL
Magic Valley Electric Cooperative, Inc.	TX
Maquoketa Valley Rural Electric Cooperative	IA
Marshall County REMC	IN
McCone Electric Co-op., Inc.	MT
McDonough Power Cooperative	IL
McKenzie Electric Cooperative, Inc.	ND
McLean Electric Coop	ND
McLeod Cooperative Power Association	MN
Meade County RECC	KY
Mecklenburg Electric Cooperative	NC,VA
Menard Electric Cooperative	IL
Middle Kuskokwim Electric Cooperative, Inc	AK
Midland Power Coop	IA
Mid-Ohio Energy Cooperative, Inc.	OH
Mid-South Electric Cooperative	TX
Midwest Electric, Inc.	OH
Midwest Energy Cooperative	IN,MI,OH
Midwest Energy, Inc.	KS
Minnesota Valley Electric Cooperative	MN
Minnkota Power Cooperative, Inc.	ND
Mississippi County Electric Cooperative, Inc.	AR
Missouri Rural Electric Cooperative	MO
Modern Electric Water Company	WA
Monroe County Electric Co-Operative, Inc.	IL
Moreau-Grand Electric Cooperative, Inc.	SD
Mountain Parks Electric, Inc.	CO
Mountain View Electric Association, Inc.	CO
Navasota Valley Electric Cooperative	TX
Navopache Electric Cooperative, Inc.	AZ,NM
Nemaha-Marshall Electric Cooperative Association, Inc	KS
New-Mac Electric Cooperative, Inc.	MO
NineStar Connect	IN
Niobrara Electric Association	NE,SD,WY
Noble County REMC	IN
Nobles Cooperative Electric	MN
Nodak Electric Coop Inc	ND
Nolin Rural Electric Cooperative Corporation	KY
North Alabama Electric Cooperative	AL
North Arkansas Electric Cooperative, Incorporated	AR
North Carolina Electric Membership Corp	NC
North Central Electric Coop	ND
North East Mississippi E P A	MS
North Georgia Electric Membership Corporation	GA
North Plains Electric Coop Inc	TX
North Star Electric Cooperative, Inc.	MN
North Western Electric Cooperative, Inc.	OH
Northeast Oklahoma Electric Cooperative	OK
Northeastern REMC	IN
Northern Lights, Inc.	ID,MT,WA
Northern Neck Electric Cooperative	VA
Northern Virginia Electric Cooperative	VA
Northwestern Electric Cooperative, Inc.	OK
Northwestern REC	PA
NorVal Electric Cooperative	MT
Nueces Electric Cooperative	TX
Oahe Electric Cooperative Inc.	SD
Oakdale Electric Coop	WI
Ocmulgee Electric Membership Corporation	GA
Oglethorpe Power Corporation	GA
Okanogan County Electric Cooperative Inc	WA
Okefenoke Rural El Member Corp	GA
Oklahoma Electric Cooperative	OK
Osceola Electric Cooperative, Inc.	IA
Otero County Electric Cooperative, Inc.	NM
Ouachita Electric Cooperative Corporation	AR
Ozark Border Electric Cooperative	MO
Ozark Electric Cooperative, Inc.	MO
Ozarks Electric Cooperative Corporation	AR,OK
Panola-Harrison Electric Cooperative, Inc.	LA,TX
Parke County Rural E M C	IN
Peace River Electric Cooperative, Inc.	FL
Pearl River Valley Electric Power Association	MS
Pee Dee Electric Membership Corp.	NC
Peninsula Light Company	WA
Pennyrile Rural Electric Coop	KY
People's Cooperative Services	MN
People's Electric Cooperative	OK
Petit Jean Electric Cooperative Corporation	AR
Pickwick Electric Cooperative	TN
Piedmont Electric Membership Corporation	NC
Pierce-Pepin Coop Services	WI
Pioneer Electric Cooperative, Inc.	AL
Pitt and Greene Electric Membership Corporation	NC
PKM Electric Coop, Inc	MN
Planters Electric Membership Corporation	GA
Polk-Burnett Electric Coop	WI
Poudre Valley Rural Electric Association, Inc.	CO
Powder River Energy Corporation	MT,WY
Prairie Energy Coop	IA
Prentiss County Electric Power Association	MS
Price Electric Coop Inc	WI
Prince George Electric Cooperative	VA
Raccoon Valley Electric Power Cooperative	IA
Raft River Rural Electric Cooperative, Inc.	ID
Ralls County Electric Cooperative	MO
Rappahannock Electric Cooperative	VA
Ravalli County Electric Cooperative, Inc.	MT
Rayburn Country Electric Cooperative, Inc.;	TX
Rayle Electric Membership Corporation	GA
REA Energy Cooperative, Inc.	PA
Red Lake Electric Cooperative, Inc.	MN
Red River Valley	MN
Red River Valley Rural Electric Association	OK
Renville-Sibley Cooperative Power Association	MN
Rich Mountain Electric Cooperative, Inc.	AR
Richland Electric Coop	WI
Rita Blanca Electric Cooperative, Inc.	TX
Riverland Energy Cooperative	WI

Cooperatively Owned Utility (Continued)

Rock Energy Cooperative	IL,WI
Rolling Hills Electric Cooperative, Inc.	KS
Roseau Electric Coop	MN
Rosebud Electric Cooperative	SD
Roughrider Electric Cooperative, Inc	ND
Rural Electric Cooperative, Inc.	OK
Rushmore Electric Power Cooperative, Inc	SD
Rusk County Electric Cooperative, Inc.	TX
Sac Osage Electric Coop, Inc	Mo
Salem Electric	OR
Salmon River Electric Cooperative, Inc.	ID
Salt River Electric Coop. Corp.	KY
Sam Houston Electric Cooperative, Inc.	TX
Sangre de Cristo Electric Association	CO
Santee Electric Cooperative, Inc.	SC
Scenic Rivers Energy Coop	WI
Se-Ma-No Electric Cooperative	MO
Sequachee Valley Electric Coop	TN
Shelby Electric Cooperative	IL
Shelby Energy Cooperative	KY
Shenandoah Valley Electric Cooperative	VA
Sheridan Electric Co-op., Inc.	MT
Sho-Me Power Electric Cooperative	MO
Sierra Electric Cooperative, Inc.	NM
Sioux Valley SW Elec Coop	MN,SD
Slash Pine Electric Membership Corporation	GA
Smarr EMC	GA
Snapping Shoals El Member Corp	GA
South Central Arkansas Electric Cooperative,	AR
South Central Electric Association	MN
South Central Power Company	OH
South Kentucky Rural Electric Coop Corp	KY,TN
South Mississippi Electric Power Association	MS
South Plains Electric Cooperative	TX
South Side Electric	ID
Southeast Electric Cooperative, Inc.	MT,SD,WY
Southeastern Electric Cooperative, Inc.	OK
Southern Illinois Power Cooperative	IL
Southern Indiana REC, Inc.	IN
Southern Maryland Electric Cooperative, Inc.	MD
Southwest Arkansas Electric Cooperative Corporation	AR
Southwest Electric Cooperative	MO
Southwest Texas Elec Coop, Inc	TX
Southwestern Electric Cooperative, Inc.	IL
Square Butte Electric Cooperative	ND
St Croix Electric Coop	WI
Steuben Rural Electric Cooperative, Inc.	NY
Sumter Electric Cooperative, Inc.	FL
Sumter Electric Membership Corporation	GA
Surry-Yadkin Elec Member Corp	NC
Suwannee Valley Electric Cooperative, Inc.	FL
T.I.P. Rural Electric Cooperative	IA
Tallapoosa River Electric Cooperative, Inc.	AL
Talquin Electric Cooperative, Inc,	FL
Taylor Electric Cooperative	WI
Tennessee Valley Electric Coop	TN
The Brown Atchison Electric Cooperative Assn., Inc.	KS
The Frontier Power Company	OH
The Midwest Electric Cooperative Corporation	NE
The Radiant Electric Cooperative, Inc.	KS
The Satilla Rural Electric Membership Corporation	GA
Three Notch Electric Membership Corporation	GA
Tippah Electric Power Association	MS
Traverse Electric Cooperative, Inc.	MN,ND,SD
Tri-County Electric Coop	MN
Tri-County Electric Cooperative, Inc	TX
Tri-County Electric Cooperative, Inc.	OK
Tri-County Electric Membership Corporation	NC
Trinity Valley Electric Cooperative, Inc.	TX
Turlock Irrigation District	CA
Twin County Electric Power Association	MS
Twin Valley Electric Cooperative	KS
Union County Electric Cooperative, Inc.	SD
Union Electric Membership Corp	NC
Union Rural Electric Coop, Inc.	OH
United Electric Cooperative	IA,MO
United Electric Cooperative Services, Inc.	TX
United Power	CO
Upper Cumberland Electric Membership Corporation	TN
Upper Missouri G & T Electric Cooperative, Inc.	MT,ND
Upshur Rural Electric Cooperative Corp	TX
Upson Electric Membership Cooperation	GA
Valley Electric Association, Inc.	CA,NV
Valley Rural Electric Cooperative, Inc.	PA
Verdigris Valley Electric Cooperative	OK
Vermont Electric Cooperative, Inc.	VT
Vernon Electric Coop	WI
Victoria Electric Coop., Inc.	TX
Vigilante Electric Cooperative, Inc	MT
Volunteer Electric Coop	TN
Wabash County REMC	IN
Wake Electric	NC
Warren Electric Cooperative, Inc	PA
Warren Rural Electric Coop Corp	KY
Washington Electric Co-Op Inc.	VT
Washington Electric Membership Corporation	GA
Wayne-White Counties Electric Cooperative	IL
Webster Electric Cooperative	MO
Wells Rural Electric Company	NV,UT
West Central Electric Cooperative, Inc.	MO
West Oregon Electric Cooperative, Inc.	OR
Western Cooperative Electric Association, Inc.	KS
Western Illinois Electrical Coop	IL
Western Indiana Energy REMC	IN
Western Iowa Power Cooperative	IA
Wheatland Electric Cooperative, Inc.	KS
Wheatland Rural Electric Cooperative	WY
Whetstone valley electric cooperative, Inc	SD
White County Rural Electric Membership Corporation	IN
Whitewater Valley REMC	IN
Wild Rice Electric Coop, Inc	MN
Wiregrass Electric Cooperative, Inc.	AL
Withlacoochee River Electric Cooperative, Inc.	FL
Woodruff Electric Cooperative Corporation	AR
Yazoo Valley Electric Power Association	MS
York Electric Cooperative, Inc.	SC

Curtailment Service Provider

Energy Curtailment Specialists, Inc.	CA,DC,DE,IL,IN,MD, NJ,NY,OH,PA,TX,VA, WV
Energy Investment Systems, Inc.	NY
Energy spectrum, Inc	NJ,NY
EnerNOC, Inc	MD
Galt Power, Inc	PA
KEYTEX Energy LLC	PA
Richards Energy Group, Inc.	PA

Federal Utility

Colorado River Indian Irrigation Project	AZ
Mission Valley Power	MT
Southeastern Power Administration	GA
Southwestern Power Administration	AR,MO,OK
Tennessee Valley Authority	AL,GA,KY,MS,NC,TN, VA
Western Area Power Administration	AZ,CA,CO,IA,KS,MN, MT,ND,NE,NJ

Investor-Owned Utility

Black Hills Power, Inc.	MT,SD,WY
AEP Texas Central Company	TX
AEP Texas North Company	TX
Alabama Power Company	AL
Alaska Power & Telephone Co	AK
Alpena Power Company	MI
Amana Society Service Co.	IA
Aniak Light & Power Co., Inc.	AK
Appalachian Power Company	VA,WV
Arizona Public Service	AZ
Atlantic City Electric Company	NJ
Avista Corporation, dba Avista Utilities	WA
Baltimore Gas and Electric Company	MD
Bangor Hydro Electric Company	ME
Bear Valley Electric Service	CA
Black Hills/Colorado Electric Utility Co. LP	CO
Block Island Power Co	RI
Central Hudson Gas & Electric Corporation	NY
Central Maine Power Co	ME
Central Vermont Public Service Corporation	VT
Cheyenne Light, Fuel and Power Company	WY
Chitina Electric, Inc.	AK
Citizens' Electric Company	PA
Cleco Power LLC	LA
Cleveland Electric Illuminating Co	OH
Columbus Southern Power Company	OH
Commonwealth Edison Company	IL
Competitive Energy Services, LLC	ME
Connecticut Light and Power Company	CT
Consolidated Edison Company of New York	NY
Consumers Energy Company	MI
Dahlberg Light and Power Company	WI
Delmarva Power and Light Company	DE,MD
Duke Energy Carolinas, LLC	NC,SC
Duke Energy Corporation	OH
Duke Energy Indiana, Inc	IN
Duke Energy Kentucky, Inc	KY
Duquesne Light Company	PA
Entergy Arkansas Inc	AR
Entergy Gulf States Louisiana, LLC	LA
Entergy Louisiana Inc.	LA
Entergy Mississippi, Inc.	MS
Entergy New Orleans, Inc.	LA
Entergy Texas, Inc.	TX
Fale-Safe, Inc	OR
Fishers Island Electric company	NY
Fitchburg Gas and Electric Light Company	MA
Florida Power & Light Company	FL
Florida Public Utilities Co.	FL
Georgia Power	GA
Granite State Electric Company	NH
Green Mountain Power Corporation	VT
Gulf Power Company	FL
Gustavus Electric Company	AK
Hawaii Electric Light Company, Inc.	HI
Hawaiian Electric Company, Inc.	HI
Hughes Power & Light Co.	AK
Idaho Power Company	ID,OR
Indiana Michigan Power Company	IN,MI
Indiana-Kentucky Electric Corp	IN
Interstate Power and Light Company	IA
Jersey Central Power & Light Co	NJ
Kansas City Power & Light Company	KS,MO
Kansas Gas & Electric Company	KS
KCP&L Greater Missouri Operations Company	MO
Kentucky Power Company	KY
Kentucky Utilities	KY
Kingsport Power Company	TN
Louisville Gas & Electric and Kentucky Utilities	KY,VA
Luminant ET Services Company	TX
Massachusetts Electric Company	MA
Maui Electric Company, Limited	HI
McGrath Light and Power	AK
Metropolitan Edison Co	PA
Miami Power Corporation	OH
MidAmerican Energy Company	IA,IL,SD
Minnesota Power, Inc.	MN
Mississippi Power	MS
Monongahela Power Co	WV
Mt Carmel Public Utility Company	IL
Nantucket Electric Company	MA
Nevada Power Company	NV
New York State Electric & Gas	NY
Niagara Mohawk Power Corporation	NY
Northern Indiana Public Service Company	IN
NorthWestern Energy	MT
NSTAR Electric Company	MA
OGE Energy Corporation	AR,OK
Ohio Edison Co	OH
Ohio Power Company	OH
Ohio Valley Electric Corporation	OH
Oncor Electric Delivery Company LLC	TX
Orange & Rockland Utilities Inc	NY

Investor-Owned Utility (Continued)

Otter Tail Power Company	MN,ND,SD
Pacific Gas and Electric Company	CA
PacifiCorp	CA,ID,OR,UT,WA,WY
PECO Energy Company	PA
Pennsylvania Electric Co	PA
Pennsylvania Power Co	PA
Portland General Electric Company	OR
Potomac Electric Power Company	DC,MD
PPL Electric Utilities	PA
Progress Energy Carolinas	NC,SC
Progress Energy Florida	FL
Public Service Company of New Hampshire	NH
Public Service Company of New Mexico (PNM)	NM
Public Service Company of Oklahoma	OK
Public Service Electric & Gas Company	NJ
Puget Sound Energy, Inc.	WA
Rochester Gas & Electric	NY
Rockland Electric Co	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 Company	SC
Southern California Edison (SCE)	CA
Southern Indiana Gas & Elec Co	IN
Southwestern Electric Power Company	AR,LA,TX
Superior Water, Light and Power Company	WI
Tampa Electric Company	FL
The Dayton Power and Light Company	OH
The Detroit Edison Company	MI
The Empire District Electric Company	AR,KS,MO,OK
The Narragansett Electric Company	RI
The Potomac Edison Company	MD,WV
The Toledo Edison Co	OH
The United Illuminating Company	CT
Tucson Electric Power	AZ
Union Electric Company	MO
Unitil Energy Systems, Inc.	NH
Upper Peninsula Power Corporation	MI,WI
Virginia Electric & Power Co	NC,VA
West Penn Power Company	PA
Westar Energy, Inc.	KS
Western Massachusetts Electric Company	CT
Wheeling Power Company	WV
Wisconsin Electric Power Company	MI,WI
Wisconsin Public Service Corporation	WI
Wisconsin River Power Company	MI,WI
Wisconsin Power and Light Company	WI
Xcel Energy	MI,WI

Municipal Power Agency

Alabama Municipal Electric Authority	AL
Centralia City Light	WA
City of Alton	IA
City of Anthony	KS
City of Bentonville - (AR)	AR
City of Drain	OR
City of Mooreland - (OK)	OK
City of New Roads	LA
City of Starke	FL
City of Vermillion	SD
Eugene Water & Electric Board	OR
Fillmore City Electric Department	UT
Indiana Municipal Power Agency	IN
Intermountain Power Agency	CA
Ipnatchiaq Electric Company	AK
Massachusetts Municipal Wholes Electric Co	MA
Missouri Basin Municipal Power Agency	SD
Municipal Electric Authority of Georgia	GA
Municipal Energy Agency of Mississippi	MS
New York Municipal Power Agency	NY
Northern Municipal Power Agency	MN
Oklahoma Municipal Power Authority	OK
Pocahontas Municipal Utilities	IA
Public Utility District No.1 of Grays Harbor County	WA
Sacramento Municipal Utility Dist	CA
Texas Municipal Power Agency	TX
Town of Pendleton	IN
Utah Municipal Power Agency	UT
Village of Trenton	NE
Vinton Public Power Authority	LA
Wyoming Municipal Power Agency	WY

Municipally Owned Utility

Adrian Public Utilities	MN
Aitkin Public Utilities	MN
Albany Water, Gas & Light Commission	GA
Algoma Utility Commission	WI
Alta Vista Municipal Utilities	IA
Ames, City of	IA
Anita Municipal Utilities	IA
Atlantic Municipal Utilities	IA
Auburn Board of Public	NE
Austin Utilities	MN
Bagley Public Utilities	MN
Bainbridge Municipal Electric Utility	IN
Bamberg Board of Public Works	SC
Bancroft Municipal Utilities	IA
Baraga Electric Utility	MI
Barnesville Municipal Electric	MN
Barton Village, Inc.	VT
Bath Electric Gas & Water System	NY
Beaver City Corporation	UT
Benton County Electric System	TN
Biwabik Public Utilities	MN
Bloomer Electric & Water Co	WI
Blooming Prairie Public Utility Commission	MN
Board of Public Works of The City of Lewes	DE
Board of Water, Electric & Communications	IA

Municipally Owned Utility (Continued)

Bolivar Energy Authority	TN
Borough of Berlin (PA)	PA
Borough of Butler- (NJ)	NJ
Borough of Ellwood City	PA
Borough of Ephrata	PA
Borough of Goldsboro	PA
Borough of Grove City	PA
Borough of Hatfield	PA
Borough of Kutztown - (PA)	PA
Borough of Lansdale	PA
Borough of Lavallette- (NJ)	NJ
Borough Of Lehighton	PA
Borough of Middletown	PA
Borough of Mifflinburg	PA
Borough of Mont Alto	PA
Borough of Olyphant- (PA)	PA
Borough of Park Ridge - (NJ)	NJ
Borough of Pemberton	NJ
Borough of Perkasie	PA
Borough of Pitcairn - (PA)	PA
Borough of Quakertown- (PA)	PA
Borough of Royalton	PA
Borough of Schuylkill Haven - (PA)	PA
Borough of Smethport	PA
Borough of South River (NJ)	NJ
Borough of St Clair- (PA)	PA
Borough of Tarentum (PA)	PA
Borough of Wampum	PA
Borough Watsontown (PA)	PA
Boscobel Municipal Utilities	WI
Borough of Catawissa	PA
Borough of Duncannon	PA
Bowling Green Municipal Utilities	KY
Boylston Municipal Light Department	MA
Brainerd Public Utilities	MN
Braintree Electric Light Department (BELD)	MA
Bremen Electric Light & Power Co	IN
Brigham City Corporation	UT
Bristol Virginia Utilities	VA
Brodhead Water & Light Commission	WI
Brooklyn Municipal Utilities	IA
Brownfield Power & Light	TX
Brownsville Public Utilities Board	TX
Brownsville Utility Department	TN
Burlington Electric Department	VT
Cairo Public Utility Company	IL
Canby Utility Board	OR
Canton Municipal Utilities	MS
Carrollton Board of Public Works	MO
Cascade Municipal Utilities	IA
Cedarburg Light & Water Commission	WI
Centerville Municipal Power & Light	IN
Centuria Municipal Electric Utility	WI
Chicopee Municipal Lighting Plant	MA
Chillicothe Municipal Utility	MO
City & Borough of Sitka, Electric Department	AK
City & County of San Francisco	CA
City of Hickman	KY
City of California	MO
City of Abbeville	LA
City of Abbeville- SC	SC
City of Aberdeen	MS
City of Acworth	GA
City of Ada	MN
City of Adel	GA
City of Afton	IA
City of Akron (IA)	IA
City of Akutan	AK
City of Albany - (IL)	IL
City of Albany- (MO)	MO
City of Albemarle	NC
City of Albion	ID
City of Alcoa Electric Department	TN
City of Alexander City	AL
City of Alexandria	MN
City of Algona	IA
City Of Alma	KS
City of Alpha	MN
City of Altamont	IL
City of Altamont - (KS)	KS
City of Anaheim Public Utilities Department	CA
City of Anoka	MN
City of Ansley	NE
City of Anthon	IA
City of Aplington	IA
City of Arapahoe	NE
City of Arcadia	WI
City of Arcadia - (KS)	KS
CITY OF ARLINGTON	MN
City of Arma	KS
City of Ashland	KS
City of Athens	AL
City of Atka	AK
City of Auburn (IA)	IA
City of Auburn Electric Utility	IN
City of Augusta	KS
City of Ava (MO)	MO
City of Axtell	KS
City of Azusa	CA
City of Blackwell	OK
City of Baldwin City Kansas	KS
City of Bandon	OR
City of Banning	CA
City oF Bartlett, Texas	TX
City of Bartow	FL
City of Bastrop	TX
City of Batavia	IL
City of Baudette	MN
City of Beaver City	NE
City of Bedford, Virginia	VA
City of Bellville (TX)	TX
City of Benham	KY
City of Benkelman	NE
City of Benton - (AR)	AR
City of Berea Municipal Utility	KY
City Of Beresford	SD

Municipally Owned Utility (Continued)

City of Bethany	MO
City of Big Stone City	SD
City of Bloomfield	IA
City of Blountstown	FL
City of Blue Earth	MN
City of Blue Mound	KS
City of Bluffton/Bluffton Utilities	IN
City of Boerne	TX
City of Boulder City	NV
City of Bountiful	UT
City of Bowie	TX
City of Brady	TX
City of Breckenridge- (MN)	MN
City of Breda	IA
City of Breese	IL
City of Brenham	TX
City of Brewster (MN)	MN
City of Bridgeport Ne	NE
City of Bristol - (TN)	TN
City of Broken Bow	NE
City of Bronson	KS
City of Brookings	SD
City of Brownton	MN
City of Bryan (OH)	OH
City of Buffalo (IA)	IA
City of Buffalo, Minnesota	MN
City of Buford	GA
City of Buhl	MN
City of Burke	SD
City of Burley - (ID)	ID
City of Burlingame	KS
City of Burlington	CO
City of Burt	IA
City of Burwell	NE
CITY OF BUSHNELL	FL
City of Butler (MO)	MO
City of Cabool	MO
City of Calhoun	GA
City of Cambridge	NE
City of Camden, SC	SC
City of Cameron	MO
City of Camilla	GA
City of Carlyle, Illinois	IL
City of Carmi, Illinois	IL
City of Cartersville, Georgia	GA
City of Cascade Locks	OR
City of Casey	IL
City of Castroville	TX
City of Cawker City	KS
City of Celina	OH
City of Central City	NE
City of Centralia (KS)	KS
City of Centralia, Missouri	MO
City of Ceylon	MN
City of Chapman	KS
City of Chattanooga - (TN)	TN
City of Chelsea	MI
City of Cheney	WA
City of Chetopa	KS
City of Chewelah	WA
City of Chignik	AK
City of Cimarron	KS
City of Claremore	OK
City of Cleveland - (OH)	OH
City of Clewiston	FL
City of Clinton- (TN)	TN
City of Clinton, Combined Utility System	SC
City of Cody	WY
City of Coffeyville, Kansas	KS
City of Colby	KS
City of Coleman	TX
City of Collins	MS
City of Collinsville	OK
City of Columbia	MO
City of Columbia City	IN
City of Columbiana	OH
City of Columbus	MS
City of Columbus, Ohio	OH
City of Comanche	OK
City of Commerce, GA	GA
City of Coon Rapids	IA
City of Corona	CA
City of Covington	GA
City of Covington - (TN)	TN
City of Cozad / Board of Public Works	NE
City of Crane (MO)	MO
City of Crete	NE
City of Crystal Falls	MI
City of Cuba	MO
City of Cushing	OK
City of Danville	IA
City of David City	NE
City of Dayton (IA)	IA
City of Denver (IA)	IA
City of Detroit Lakes	MN
City of Dighton	KS
City of Dike	IA
City of Doerun	GA
City of Dothan	AL
City of Douglas	GA
City of Dover Public Utilities	DE
City of Dowagiac	MI
City of Due West	SC
City of Duncan	OK
City of Durant (IA)	IA
City of Dysart	IA
City of Earlville	IA
City of East Grand Forks - (MN)	MN
City Of East Point Power East Point Georgia	GA
City of Eaton Rapids	MI
City of Edgar (NE)	NE
City of Edmond	OK
City of Egegik	AK
City of Elberton	GA
City of Elfin Cove	AK
City of Elizabethton	TN

Municipally Owned Utility (Continued)

City of Elk Point	SD
City of Ellaville	GA
City of Ellensburg	WA
City of Ellsworth	IA
City of Elroy	WI
City of Elwood	KS
City of Emerson	NE
City of Enterprise	UT
City of Erie (KS)	KS
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 Fairview	OK
City of Faith	SD
City of Fallon (NV)	NV
City of Falls City	NE
City of Farmersville	TX
City of Farmington	NM
City of Fayetteville	TN
City of Flandreau	SD
City of Flora	IL
City of Florence (AL)	AL
City of Floresville	TX
City of Fonda	IA
City of Fontanelle	IA
City of Forest Grove Light and Power	OR
City of Fort Meade	FL
City of Fort Morgan	CO
City of Fort Pierre - (SD)	SD
City of Fosston	MN
City of Fountain	CO
City of Franklin (NE)	NE
City of Franklin Power & Light	VA
City of Frederick	OK
City of Fredonia	KS
City of Fulton	MO
City of Galion	OH
City of Gallatin	MO
City of Gallup	NM
City Of Galt	MO
City of Galva	KS
City of Garden City	KS
City Of Garland	TX
City Of Gas City	IN
City of Gastonia	NC
City of Geary	OK
City of Geneseo	IL
City of Geneva	IL
City of Georgetown	TX
City of Giddings	TX
City of Gilbert	MN
City of Giltner	NE
City of Gladstone	MI
City of Glasco	KS
City of Glen Elder	KS
City of Glendale	CA
City of Glenwood Springs - CO	CO
City of Goldthwaite	TX
City of Gonzales	TX
City of Goodland	KS
City of Gothenburg	NE
City of Graettinger	IA
City of Grafton - (ND)	ND
City of Grand Island	NE
City of Grand Junction (IA)	IA
City of Granite	OK
City of Grant	NE
City of Grantville	GA
City of Greendale	IN
City of Greensburg (KS)	KS
City of Gridley	CA
City of Griffin	GA
City of Groton	SD
City of Grove City	MN
City of Guttenberg	IA
City of Hagerstown, IN	IN
City of Hallettsville	TX
City of Halstad	MN
City of Hampton	GA
City of Harbor Springs	MI
City of Harrisonville	MO
City of Hart Hydro	MI
City of Hartford (AL)	AL
City of Hartley	IA
City of Hastings	NE
City of Haven	KS
City of Hawarden	IA
City of Healdsburg (CA)	CA
City of Hebron	NE
City of Hecla	SD
City of Hemphill	TX
City of Henning	MN
City of Herington	KS
City of Hermann	MO
City of Herndon	KS
City of Hertford (NC)	NC
City of Higginsville	MO
City of Highland	IL
City of Hill City	KS
City of Hillsboro	KS
City of Holdrege	NE
City of Hominy (OK)	OK
City of Hope	ND
City of Hopkinton	IA
City of Horton	KS
City of Houston	MO
City of Howard	SD
City of Hubbard	OH
City of Hubbell	NE
City of Hudson	OH
City of Hugoton	KS

Municipally Owned Utility (Continued)

City of Hunnewell	MO
City of Huntingburg - (IN)	IN
City of Imperial	NE
City of Indianola	NE
City of Isabel (KS)	KS
City of Itta Bena	MS
City of Iuka	KS
City of Jackson	GA
City of Jackson (OH)	OH
City of Jacksonville Beach	FL
City of Janesville	MN
City of Jasper, TX	TX
City of Jetmore	KS
City of Jonesville (LA)	LA
City of Kahoka	MO
City of Kandiyohi	MN
City of Kansas City	KS
City of Kasson	MN
City of Kennett	MO
City of Kiel	WI
City of Kimball	NE
City of Kingfisher	OK
City of Kings Mountain	NC
City of Kiowa (KS)	KS
City of Kirkwood (MO)	MO
City of La Crosse	KS
City of La Grange	TX
City of La Grange (GA)	GA
City of La Plata	MO
City of Lafayette	AL
City of Lake City Electric Utility	MN
City of Lake Crystal (MN)	MN
City of Lake Mills	IA
City of Lake Park- (IA)	IA
City of Lake View	IA
City of Lake Worth Utilities	FL
City of Lakefield	MN
City of Lakeland, Lakeland Electric	FL
City of Lakota	ND
City of Lamar	MO
City of Lamar- (Colorado)	CO
City of Lampasas (TX)	TX
City of Lanett	AL
City of Larchwood	IA
City of Larned	KS
City of Larsen Bay	AK
City of Las Animas Municipal Light & Power	CO
City of Laurel (NE)	NE
City of Laurens	IA
City of Laurinburg	NC
City of Lawler (IA)	IA
City of Lawrenceville	GA
City of Le Sueur (MN)	MN
City of Lebanon	OH
City of Lehigh	IA
City of Lenox (IA)	IA
City of Lexington	NE
City of Liberal	MO

City of Liberty	TX
City of Lincoln Center	KS
City of Lincoln Electric System	NE
CITY OF LINDSAY	OK
City of Lindsborg	KS
City of Linneus (MO)	MO
City of Litchfield Public Utilities	MN
City of Livermore	IA
City of Livingston	TX
City of Lockhart	TX
City of Lodgepole (NE)	NE
City of Lodi	CA
City of Lompoc	CA
City of Long Grove (IA)	IA
City of Lowell	MI
City of Lucas	KS
City of Luray (KS)	KS
City of Luverne	MN
CITY OF LYONS	NE
City of Mabel (MN)	MN
City of Maddock	ND
City of Madison (MN)	MN
City of Madison (NE)	NE
City of Malden (MO) Board of Public Works	MO
City of Mangum (OK)	OK
City of Manitou (OK)	OK
City of Mankato	KS
City of Manokotak	AK
City of Mansfield	MO
City of Mansfield (GA)	GA
City of Mapleton	IA
City of Marathon	IA
City of Marietta (GA)	GA
City of Marion	KS
City of Marshall	IL
City of Marshall, Michigan	MI
City of Marshfield	WI
City of Martinsville Electric Department	VA
City of Mascoutah	IL
City of Mason	TX
City of McLeansboro	IL
City of McMinnville (OR)	OR
City of Meade	KS
City of Meadville	MO
City of Memphis (MO)	MO
City of Mendon - (OH)	OH
City of Mesa	AZ
City of Milan	TN
City of Milan (MO)	MO
City of Milford	DE
City of Milford (IA)	IA
City of Miller (SD)	SD
City of Milton	WA
City of Minden	LA
City of Minden (NE)	NE
City of Mindenmines (MO)	MO
City of Mindoka (ID)	ID
City of Minneapolis (KS)	KS

Municipally Owned Utility (Continued)

City of Mishawaka	IN
City of Monmouth	OR
City of Monroe	GA
City of Montezuma (IA)	IA
City of Montezuma (KS)	KS
City of Monticello	GA
City of Moore Haven (FL)	FL
City of Mora (MN)	MN
City of Moran	KS
City of Moreno Valley (CA)	CA
City of Morrill	KS
City of Moultrie	GA
City of Mount Dora	FL
City of Mount Hope (KS)	KS
City of Mount Vernon	MO
City of Mountain Iron	MN
City of Mountain Lake	MN
City of Mountain View	MO
City of Mt Pleasant	UT
City of Mulberry (KS)	KS
City of Mulvane - - (KS)	KS
City of Murray	UT
City of Nashwauk	MN
City of Natchitoches	LA
City of Nebraska City	NE
City of Needles	CA
City of Neligh	NE
City of Neodesha (KS)	KS
City of Neola (IA)	IA
City of New Braunfels - (TX)	TX
City of New Hampton (IA)	IA
City of New Lisbon Municipal Electric & Water Dept.	WI
City of New Madrid (MO)	MO
City of New Ross	IN
City of Newberry, Florida	FL
City of Newburg (MO)	MO
City of Newkirk	OK
City of Newton	IL
City of Nicholasville	KY
City of Nielsville	MN
City of Niles (MI)	MI
City of Nixa Utilities	MO
City of North Saint Paul	MN
City of Northwood	ND
City Of Norton Kansas	KS
City of Norway Dept. of Power & Light	MI
City of Oberlin (KS)	KS
City of Ocala Utility Services	FL
City of Odessa	MO
City of Oglesby (IL)	IL
City of Olivia (MN)	MN
City of Onawa	IA
City of Onida (SD)	SD
City of Opelika	AL
City of Ord	NE
City of Orient (IA)	IA
City of Ortonsville - (MN)	MI
City of Osage City	KS
City of Osawatomie	KS
City of Osborne	KS
City of Osceola	MO
City of Osceola (AR)	AR
City of Osford	KS
City of Oxford (GA)	GA
City of Painesville	OH
City of Palo Alto Utilities	CA
City of Paris (AR)	AR
City of Paris (KY)	KY
City of Park River - (ND)	ND
City of Pasadena	CA
City of Paton - (IA)	IA
City of Perry, MO.	MO
City of Peterson	MN
City of Petoskey	MI
City of Piedmont	AL
City of Pierce	NE
City of Pierre	SD
City of Pierz	MN
City of Piqua (OH)	OH
City of Plainview (NE)	NE
City of Plaquemine (LA)	LA
City of Plattsburgh - (NY)	NY
City of Pomona (KS)	KS
City of Poplar Bluff	MO
City of Port Angeles	WA
City of Pratt (KS)	KS
City of Preston	IA
City of Princeton	IL
City of Princeton (WI)	WI
City of Pryor (OK)	OK
City of Purcell	OK
City of Quitman	GA
City of Radford - Electric Department	VA
City of Radium	KS
City of Rancho Cucamonga	CA
City of Randall	MN
City of Randolph (NE)	NE
City of Rayne	LA
City of Readlyn (IA)	IA
City of Red Cloud	NE
City of Redding	CA
City of Renwick (IA)	IA
City of Richland	WA
City of Rising Sun (IN)	IN
City of Riverdale	ND
City of Robertsdale	AL
City of Robinson	KS
City of Rock Hill	SC
City of Rockwood	TN
City of Roodhouse	IL
City of Roseau	MN
City of Roseville	CA
City of Round Lake	MN
City of Rupert	ID
City of Rushford	MN
City of Rushmore - (MN)	MN

Municipally Owned Utility (Continued)

City of Russell	KS
City of Russell (MA)	MA
City of Ruston (LA)	LA
City of Sabula	IA
City of Saint Peter	MN
City of Salamanca	NY
City of Salem	VA
City of Sanborn	IA
City of Sauk Centre	MN
City of Schuyler (NE)	NE
City of Scranton	KS
City of Scribner	NE
City of Seaford	DE
City of Sebewaing (MI)	MI
City of Seguin	TX
City of Seneca	SC
City of Seward (AK)	AK
City of Seymour (TX)	TX
City of Shasta Lake	CA
City of Sheboygan Falls	WI
City of Shelbina	MO
City of Shelby (NC)	NC
City of Shelby (OH)	OH
City of Sherrill Power & Light	NY
City of Shiner	TX
City of Shullsburg (WI)	WI
City of Sibley	IA
City of Sidney	NE
City of Siloam Springs (AR)	AR
City of Sioux Falls (SD)	SD
City of Slater	MO
City of Smithville	TX
City of Snyder	NE
City of Soda Springs	ID
City of South Sioux City	NE
City of Spring Grove	MN
City of Springfield	CO
City of Springfield, IL	IL
City of St Charles	IL
City of St Louis	MI
City Of St Marys	KS
City of St Robert (MO)	MO
City of St. Charles	MN
City of St. Clairsville	OH
City of St. George	UT
City of St. James	MN
City Of St. John	KS
City of St. Marys	OH
City of Stafford (KS)	KS
City of Stanhope	IA
City of Stanton	ND
City of Stanton (IA)	IA
City of Starkville	MS
City of State Center	IA
City of Statesville (NC)	NC
City of Stephen - (MN)	MN
City of Stephenson	MI
City of Stockton	KS
City of Strawberry Point	IA
City of Stroud (OK)	OK
City of Stuart (NE)	NE
City of Sullivan	MO
City of Sumas	WA
City of Superior (NE)	NE
City of Sutton	NE
City of Sylvania (GA)	GA
City of Syracuse	NE
City of Tallahassee Utilities	FL
City of Taunton	MA
City of Tecumseh	NE
City of Tenakee Springs	AK
City of Thayer	MO
City of Thief River Falls	MN
City of Timpson (TX)	TX
City of Toronto (KS)	KS
City of Traverse City	MI
City of Trenton (TN)	TN
City of Trinidad	CO
City of Troy	KS
City of Troy - (IN)	IN
City of Troy	AL
City of Tulia	TX
City of Tupelo - (MS)	MS
City of Tuskegee	AL
City of Two Harbors	MN
City of Tyler	MN
City of Tyndall	SD
City of Udall	KS
City of Unalaska	AK
City of Union City	TN
City of Union	SC
City of Unionville	MO
City of Valentine	NE
City of Valley City	ND
City of Vandalia	MO
City of Vermillion (KS)	KS
City of Versailles	OH
City of Virginia	MN
City of Wadena Electric & Water	MN
City of Wakefield (NE)	NE
City of Wall Lake	IA
City of Wamego	KS
City of Warren - (MN)	MN
City Of Warroad	MN
City of Washington (IN)	IN
City of Washington (KS)	KS
City of Washington	GA
City of Waterloo	IL
City of Watertown	NY
City of Wathena	KS
City of Wauchula	FL
City of Weiser	ID
City of Wellington	KS
City of West Liberty	IA
City of West Plains	MO
City of Westbrook	MN

Municipally Owned Utility (Continued)

City of Westfield	MA
City of Whalan	MN
City of Whigham	GA
City of White	SD
City of Whittemore	IA
City of Wilber	NE
City of Willow Springs	MO
City of Windom	MN
City of Winfield (KS)	KS
City of Winner	SD
City of Winnfield	LA
City of Winona	MO
City of Winterset (IA)	IA
City of Winterville	NC
City of Winthrop (MN)	MN
City of Wisner	NE
City of Woolstock	IA
City of Wrangell	AK
City of Wray	CO
City of Wymore (NE)	NE
City of Yoakum, Texas	TX
City Utilities of Springfield, MO	MO
City Water & Light Plant of the City of Jonesboro	AR
City of Girard	KS
Clarksdale Public Utilities	MS
Clarksville Light & Water Co	AR
Clintonville Utilities	WI
Colorado Springs Utilities	CO
Columbia Power & Water Systems	TN
Columbus Water & Light Dept.	WI
Conway Corporation	AR
Corbin City Utilities Commission	KY
Corwith Municipal Utilities	IA
Crawfordsville Electric Light & Power	IN
Cuba City Electric & Water Utility	WI
Cumberland, City of	WI
Cuyahoga Falls Electric System	OH
D.G. Hunter Power Station	LA
Darlington Light & Power Co	IN
Delano Municipal Utilities	MN
Delta Municipal Light and Power	CO
Dublin Municipal Electric Utilities	IN
Eagle River Light & Water Commission	WI
Easley Combined Utility System	SC
East Bay Municipal Utility District	CA
Easton Utilities Commission	MD
Ediburg Municipal Utilities	IN
Electric and Water Plant Board of the City of Frankfort	KY
Elk River Municipal Utilities	MN
Evansville Water & Light	WI
Fairburn Utilities	GA
Fitzgerald Wtr Lgt	GA
Florence Utility Commission	WI
Foley Board of Utilities	AL
Forest City Municipal Utilities	IA
Fort Collins Utilities	CO
Fort Pierce Utilities Authority	FL
Fremont Department of Utilities	NE
Gaffney Board of Public Works	SC
Gainesville Regional Utilities	FL
Galena Electric Utility	AK
Gallatin Department of Electricity	TN
Glasgow Electric Plant Board	KY
Glencoe Light and Power Commission	MN
Gold Country Energy	AK
Goltry Public Works Authority	OK
Grafton Electric	IA
Grand Haven Board of Light and Power	MI
Green Cove Springs Electric Utility	FL
Greenfield Municipal Utilities	IA
Greenwood Commissioners Public Works	SC
Greenwood Utilities	MS
Groton Electric Light Dept.	MA
Grundy Center Mun. Light & Power	IA
Harriman Utility Board	TN
Harrisonburg Electric Commission	VA
Hartford Utilities	WI
Havana Power & Light Company	FL
Hawley Public Utilities	MN
Heber Light & Power Company	UT
Helper City	UT
Henderson Power and Light	KY
Hermiston Energy Services	OR
Hibbing Public Utilities	MN
Hingham Municipal Light Plant	MA
Holland Board of Public Works	MI
Holy Springs Utility Department	MS
Hooversville Electric Light Co	PA
Hope Water and Light Commission	AR
Hopkinsville Electric System	KY
Hudson Light & Power Department	MA
Hudson Municipal Electric Utility	IA
Hurricane City Power	UT
Hustisford Utilities	WI
Hutchinson Utilities Commission	MN
Hyrum City Corp.	UT
Idaho Falls Power	ID
Illinois Municipal Electric Agency	IL
Independence Light & Power	IA
Indianola Municipal Utilities	IA
Jamestown Board of Public Utilities	NY
JEA	FL
Jefferson Water & Light Dept.	WI
Jewett City Department of Public Utilities	CT
Juneau Utility Commission	WI
Kaukauna Utilities	WI
Kaysville City Corporation	UT
Keewatin Public Utilities	MN
Kennebunk Light & Power District	ME
Kenyon Municipal Utility	MN
Kerrville Public Utility Board	TX
Ketchikan Public Utilities	AK
Kimballton Municipal Utilities	IA
Kirbyville Light & Power Co	TX
Kissimmee Utility Authority	FL
Knoxville Utilities Board	TN

Municipally Owned Utility (Continued)

Kokhanok Village Council	AK
Kosciusko Water & Light Plant	MS
La Farge Municipal Electric Co.	WI
La Porte City Utilities	IA
Lafayette Utilities System	LA
Lake Mills Light & Water Dept.	WI
Lake Placid Village, Inc.	NY
L'anse Electric Utility	MI
Lansing Board of Water & Light	MI
Lassen Municipal Utility District	CA
Lawrenceburg Municipal Utilities	IN
Lebanon Utilities	IN
Levan Town Corporation	UT
Lexington Electric System	TN
Littleton Water and Light Department	NH
Lockwood Water & Light Company	MO
Lodi Municipal Light & Water Utility	WI
Logan City Light and Power	UT
Logansport Municipal Utilities	IN
Longmont Power & Communications	CO
Los Angeles Department of Water and Power	CA
Louisville Electric System	MS
Madelia Municipal Light & Power	MN
Manitowoc Public Utilities	WI
Manti City	UT
Maquoketa Municipal Electric Utility	IA
Marquette Board of Light and Power	MI
Marshall Municipal Utilities	MN
Matinicus Plantation Electric Co	ME
Mayor & Council of Middletown	DE
McMinnville Electric System	TN
Meadow Town Corp.	UT
Memphis Light, Gas & Water Division	TNI
Menasha Electric & Water Utilities	WI
Merrimac Municipal Light Department	MA
Metlakatla Power & Light	AK
Monroe City	UT
Moorhead Public Service	MN
Morgan City (LA)	LA
Morgan City Corporation	UT
Morristown Utilities Commission	TN
Mount Horeb Electric Utility	WI
Mount Pleasant Municipal Utilities	IA
Municipal Commission of Boonville	NY
Municipal Electric Utility of the City of Cedar Falls	IA
Municipal Services Commission	DE
Muscoda Light & Water Utility	WI
Negaunee Electric Department	MI
New Glarus Light & Water Works	WI
New Hampton Village Precinct	NH
New Holstein Public Utility	WI
New London Electric & Water Utility	WI
New Martinsville Municipal Electric Utility	WV
New Richmond Municipal Electric Utility	WI
New Ulm Public Utilities Comm	MN
Newberry Water & Light Board	MI
Nome Joint Utility System	AK
North Branch Water & Light Comm.	MN
North Little Rock Electric Department	AR
Norwich Public Utility	CT
Oconto Falls Water & Light Commission	WI
Okeene Public Works Authority	OK
Orlando Utilities Commission	FL
Orrville Utilities	OH
Osage Municipal Utilities	IA
Owatonna Public Utilities	MN
Owensboro Municipal Utilities	KY
Page Electric Utility	AZ
Palmrya Board of Public Works	MO
Paragould Light Water and Cable	AR
Parowan City Corporation	UT
Pascoag Utility District	RI
Payson City Corporation	UT
Pella City of	IA
Pend Oreille PUD	WA
Piggott Light and Water	AR
Plymouth Utilities	WI
Prague Public Works Authority	OK
Prairie du Sac Municipal Electric & Water	WI
Precinct of Woodsville	NH
Price Municipal Corporation	UT
Princeton Public Utilities Commission	MN
Proctor Public Utilities Commission	MN
Prospect Corporation	OH
Provo City Corporation	UT
Public Works Commission of the City of Fayetteville	NC
PUD No 1 of Asotin County	WA
PUD No 1 of Skamania Co	WA
Raton Public Service Company	NM
Redwood Falls Public Utility Commission	MN
Reedsburg Utility Commission	WI
Reedy Creek Improvement District	FL
Rensselaer Municipal Electric Utility	IN
Reynolds, Village of	NE
Rice Lake Utilities	WI
Richland Center Electric Utility	WI
Richmond Power and Light	IN
River Falls Municipal Utility	WI
Riverside Public Utilities	CA
Rochelle Municipal Utilities	IL
Rock Port Municipal Utilities	MO
Rock Rapids Municipal Utilities	IA
Rockford Municipal Light Plan	IA
Sallisaw Municipal Authority	OK
Santa Clara City	UT
Second Taxing District of Norwalk	CT
Sevier County Electric System	TN
Shakopee Public Utilities Commission	MN
Shawano Municipal Utilities	WI
Sikeston Board of Municipal Utilities	MO
Silicon Valley Power, City of Santa Clara	CA
Sioux Center Municipal Electric Utility	IA
Sleepy Eye Public Utilities	MN
Slinger Utilities	WI
Smithville Electric System	TN
Snohomish County PUD No 1	WA

Municipally Owned Utility (Continued)

South Hadley Electric Light Department	MA
South Vienna Corporation	OH
Spanish Fork City Corporation	UT
Spencer Municipal Utilities	IA
Spencerport Electric	NY
Spooner Municipal Utilities	WI
Spring Valley Public Utilities	MN
Springville Light & Power	UT
Stoughton Electric Utility	WI
Straughn Municipal Electric	IN
Stuart Municipal Utilities	IA
Sturgeon Bay Utilities	WI
Sumner Municipal Light Plant	IA
Sun Prairie Water & Light Commission	WI
Sylacauga Utilities Board	AL
Tacoma Public Utilities	WA
TDX Manley Generating LLC	AK
Tell City Electric Department	IN
The City of Holyoke Gas and Electric Department	MA
The Hagerstown Light Department	MD
Third Taxing District Electric Dept.	CT
Tipton Municipal Electric Utility	IN
Tipton Municipal Utilities	IA
Town of Argos Utilities	IN
Town of Ashburnham	MA
Town of Avilla	IN
Town of Bargersville	IN
Town of Belmont	MA
Town of Black Creek	NC
Town of Blackstone	VA
Town of Bostic	NC
Town of Boyce	LA
Town of Brinson	GA
Town of Brooklyn	IN
Town of Clayton (NC)	NC
Town of Coatesville	IN
Town of Coulee Dam	WA
Town of Crane	IN
Town of Culpeper Light & Power	VA
Town of Dallas	NC
Town of Eatonville	WA
Town of Etna Green	IN
Town of Ferdinand	IN
Town of Forest City	NC
Town of Fountain	NC
Town of Frankton	IN
Town of Frederick	CO
Town of Fredonia	AZ
Town of Front Royal	VA
Town of Granada	CO
Town of Granite Falls	NC
Town of Groveland	MA
Town of Guernsey	WY
Town of Gueydan	LA
Town of Hardwick	VT
Town of Haxtun	CO
Town of High Point	NC
Town of Highlands	NC
Town of Hobgood	NC
Town of Ipswich	MA
Town of Julesburg	CO
Town of Kingsford Heights	IN
Town of Knightstown (Municipal Electric Utility)	IN
Town of Ladoga (IN)	IN
Town of Landis	NC
Town of Laverne- (OK)	OK
Town of Lewisville	IN
Town of Lucama	NC
Town of Lyons	CO
Town of MacClesfield	NC
Town of Madison (ME)	ME
Town of Maiden (NC)	NC
Town of Manilla (IA)	IA
Town of Mansfield (MA)	MA
Town of Massena Electric Department	NY
Town of Middleborough (MA)	MA
Town of Middletown-(IN)	IN
Town of Montezuma	IN
Town of New Carlisle (IN)	IN
Town of Oak City	UT
Town of Paxton Municipal Light Department	MA
Town of Pinetops	NC
Town of Pineville (NC)	NC
Town of Princeton (MA)	MA
Town of Prosperity, SC	SC
Town of Rowley (MA)	MA
Town of Ruston (WA)	WA
Town of Ryan (OK)	OK
Town of Scotland Neck (NC)	NC
Town of Sharpsburg	NC
Town of South Whitley	IN
Town of Spiceland	IN
Town of Spiro	OK
Town of Stantonsburg	NC
Town of Stowe	VT
Town of Templeton (MA)	MA
Town of Veedersburg	IN
Town of Vidalia	LA
Town of Wakefield (VA)	VA
Town of Walkerton	IN
Town of Wallingford, Department of Public Utilities	CT
Town of Walstonburg	NC
Town of Waynesville	NC
Town of Winamac	IN
Town of Winnsboro	SC
Town of Wolfeboro	NH
Traer Municipal Utilities	IA
Trenton Municipal Utilities	MO
Tullahoma Board of Public Utilities	TN
Two Rivers Water & Light Utility	WI
Van Buren Light & Power District	ME
Village of Akron	NY
Village of Angelica	NY
Village of Arcade	NY
Village of Arcadia	OH
Village of Arnold	NE

Municipally Owned Utility (Continued)

Village of Bartley	NE
Village of Belmont	WI
Village of Bergen	NY
Village of Bethany Illinois	IL
Village of Black Earth	WI
Village of Blanchester	OH
Village of Brainard	NE
Village of Brocton	NY
Village of Callaway	NE
Village of Campbell (NE)	NE
Village of Carey	OH
Village of Castile	NY
Village of Chester	NE
Village of Churchville	NY
Village of Clinton	MI
Village of Daggett	MI
Village of Davenport	NE
Village of De Witt	NE
Village of Deshler	OH
Village of Dorchester	NE
Village of Endicott Municipal Light	NY
Village of Fairport	NY
Village of Frankfort (NY)	NY
Village of Freeburg	IL
Village of Freeport	NY
Village of Glouster	OH
Village of Grafton	OH
Village of Greene	NY
Village of Greenport	NY
Village of Hampton	NE
Village of Haskins	OH
Village of Hazel Green	WI
Village of Hemingford/Hemingford Municipal Utilities	NE
Village of Holbrook	NE
Village of Holley Municipal Electric Department	NY
Village of Jackson Center - (OH)	OH
Village of Lakeview (OH)	OH
Village of Little Valley	NY
Village of Lodi (OH)	OH
Village of Lucas	OH
Village of Lyndonville	VT
Village of Marshallville	OH
Village of Mayville	NY
Village of Merrillan (WI)	WI
Village of Morrill (NE)	NE
Village of New Bremen (OH)	OH
Village of New Knoxville (OH)	OH
Village of Oak Harbor (OH)	OH
Village Of Oxford	NE
Village of Paw Paw	MI
Village of Pemberville (OH)	OH
Village of Philadelphia	NY
Village of Polk - (NE)	NE
Village of Rantoul	IL
Village of Rockville Centre	NY
Village of Seville Board of Public Affairs	OH
Village of Sherburn	NY
Village of Shickley	NE
Village of Silver Springs Municipal Electric	NY
Village of Skaneateles (NY)	NY
Village of Spalding	NE
Village of Spencer	NE
Village of Springville	NY
Village of Stratford	WI
Village of Stratton	NE
Village of Swanton	VT
Village of Talmage	NE
Village of Theresa	NY
Village of Tontogany	OH
Village of Tupper Lake	NY
Village of Viola	WI
Village of Watkins Glen	NY
Village of Wellington	OH
Village of Westfield	NY
Village of Wharton	OH
Village of Winnetka	IL
Vinton Municipal Electric Utility	IA
Bowling Green	OH
Wadsworth Utilities	OH
Wagoner Public Works Authority	OK
Walters Public Works Authority	OK
Washington City Power	UT
Waterloo Water & Light Commission	WI
Waunakee Water & Light Commission	WI
Waupun Utilities	WI
Waverly Municipal Elec Utility	IA
Weakley County Municipal Electric System	TN
Weatherford Municipal Utility System	TX
West Boylston Lighting Plant	MA
West Point Municipal Utility	IA
Westby Municipal Electric Utility	WI
Williamstown Utility Commission	KY
Wilton Municipal Light and Power	IA
Wisconsin Dells Electric Utility	WI
Wonewoc Municipal Water & Light Dept	WI
Wyandotte Municipal Service Commission	MI
Wynnewood City Utilities Authority	OK

Political Subdivision

Alamo Power District #3	NV
Arkansas River Power Authority	CO
Butler Public Power District	NE
Cedar-Knox PPD	NE
Chimney Rock Public Power District	NE
City of El Dorado Springs	MO
City of Steelville	MO
Clatskanie PUD	OR
Cornhusker Public Power District	NE
Dawson Public Power District	NE
Eastside Power Authority	CA
Electrical District # 2	AZ
Electrical District No. 4 Pinal County	AZ
Electrical District No. 5 Pinal County	AZ
Elkhorn Rural Public Power District	NE
Emerald People's Utility District	OR
Howard Greeley Rural Public Power District	NE

Political Subdivision (Continued)

Kings River Conservation District	CA
Kwig Power Company	AK
Louisiana Energy and Power Authority	LA
Loup River Public Power District	NE
Loup Valleys Rural Public Power District	NE
McCook Public Power District	NE
Merced Irrigation District	CA
Midvale Irrigation District	WY
North Central Public Power District	NE
Northeast Nebraska Public Power District	NE
Oakdale & South San Joaquin Irrigation D.	CA
Overton Power District No. 5	NV
Perennial Public Power District	NE
Placer County Water Agency	CA
Platte River Power Authority	CO
Polk County Rural Public Power District	NE
Public Service Commission of Yazoo City	MS
Public Utility District #1 of Ferry County	WA
Public Utility District No. 1 of Wahkiakum County	WA
PUD #1 of Clallam County	WA
PUD No 1 of Clark County	WA
PUD No 1 of Klickitat County	WA
PUD No 3 of Mason County	WA
PUD No. 1 of Whatcom County	WA
Roosevelt Public Power District	NE
Salt River Project Agricultural Improvement & Power	AZ
South Feather Water and Power Agency	CA
Southern California PPA	CA
Southern Public Power District	NE
Southwest Public Power District	NE
The Central Nebraska Public Power and Irrigation	NE
Tillamook People's Utility District	OR
Tohono O'odham Utility Authority	AZ
Tonopah Irrigation District	AZ
Village of Endicott	NE
WPPI Energy	WI

Regional Transmission Organization/ Independent Transmission Operator

California Independent System Operator	CA
Electric Reliability Council of Texas	TX
ISO New England	MA
Midwest ISO	IN
New York Independent System Operator	NY
PJM Interconnection, LLC	PA
Southwest Power Pool	AR

Retail Power Marketer

3 Phases Renewables	CA
Accent Energy Holdings, LLC	NY,TX
Agway Energy Services, LLC	NY
Ameren Energy Marketing	IL
Amigo Energy	TX
Anthracite Power & Light	PA
AP Holdings, LLC	NY,PA,TX
APN Starfirst, L.P.	PA
APNA Holdings LLC dba APNA Energy	TX
CPL Retail Energy, LP	TX

Wholesale Power Marketer

AES Eastern Energy LP	NV
Badger Power Marketing Auth	WI
CL Power Sales Eight LLC	CA
CP Power Sales Seventeen LLC	MA
Dynegy Power Marketing, LLC	TX

Direct Energy Services, LLC	CT,DC,DE,IL,MA,MD, ME,NJ,NY,OH,PA,RI
Direct Energy, LP	TX
Dow Hydrocarbons and Resources LLC.	TX
Energy Plus Holdings LLC	CT,IL,MD,NJ,NY,PA, TX
En-Toucn Systems, Inc. d/b/a En-Touch Energy	TX
First Choice Power	TX
Gateway Energy Services Corporation	MD,NJ,NY,PA
Integrys Energy Services of New York, Inc.	NY
Integrys Energy Services, Inc.	CT,DC,DE,IL,MA,MD, ME
MxEnergy Electric, Inc.	TX
Power Choice/ Pepco Energy Serv	DC,DE,IL,MA,MD,NJ, NY,PA,TX
Shell Energy North America, LP	TX
South Jersey Energy	NJ
Spartan Renewable Energy, Inc.	MI
Tara Energy, LLC	TX
Texas Retail Energy, LLC	TX
TXU Energy Retail Company LLC	TX
U.S. Energy Partners LLC	NY
UGI Energy Services, Inc.	DC,DE,MD,NJ,NY,PA
Wolverine Power Marketing Cooperative	MI
WTU Retail Energy, LP	TX

State Utility

Alaska Energy Authority	AK
Commonwealth Utilities Corporation	MP
Energy Northwest	WA
Grand River Dam Authority	OK
Nebraska Public Power District	NE,SD
New York Power Authority	NY
South Carolina Public Service Authority	SC
The Metropolitan Water District of Southern Calif	CA
Toledo Bend Project Joint Operations	TX
Virginia Tech Electric Service	VA
ITC Great Plains	KS,OK
ITC Midwest LLC	IA,IL,MN,MO
ITC Transmission	MI
Michigan Electric Transmission Company	MI
Swans Island Electric Coop Inc	ME
Vermont Electric Power Co, Inc	VT
Vermont Electric Trans Co Inc	VT

Edison Mission Marketing & Trading, Inc. - WSPP	MA
GenOn Energy Management, LLC	FL,IL,MA,MD,MS,NJ,NY,OH,PA,TX,VA
Great Bay Power Marketing, Inc.	MA,ME,NH,NJ,NY,VT
Guthrie County Rural Electric Cooperative	IA
H.Q. Energy Services (U.S.) Inc.	CT
JP Morgan	TX
Luminant Energy Company LLC	TX
Macquarie Energy LLC	TX
NextEra Energy Power Marketing, LLC	FL
PPL EnergyPlus LLC	MT
PSEG Energy Resources & Trade LLC	NJ
Rainbow Energy Marketing Corporation	ND
RRI Energy Services, LLC	TX
Select Energy, Inc.	TX
Sunflower Electric Power Corporation	KS
TransAlta Energy Marketing	NY

APPENDIX F: DEMAND RESPONSE PROGRAMS AND SERVICES AT RESPONDING ENTITIES

Appendix F lists entities that responded to the 2012 FERC Survey and indicated that they offer one or more demand response programs, organized by demand response program type.

Critical Peak Pricing

Butler Rural Electric Cooperative, Inc.
Canadian Valley Electric Cooperative
City of Algona
City of Palo Alto Utilities
Clay Electric Cooperative, Inc.
Fairfield Electric Cooperative Inc.
Flint Electric Membership Corporation
Green Mountain Power Corporation
High Plains Power, Inc.
Jackson Electric Membership Corporation
JEA
OGE Energy Corporation
Rayle Electric Membership Corporation
Red River Valley Rural Electric Association
Richmond Power and Light
Rural Electric Cooperative, Inc.
Sacramento Municipal Util Dist
San Diego Gas & Electric
Sioux Valley SW Elec Coop
Southern California Edison (SCE)
Tampa Electric Company
The Detroit Edison Company
Town of High Point
United Power
Wisconsin Public Service Corporation
Wynnewood City Utilities Authority

Critical Peak Pricing with Load Control

Adams Electric Cooperative, Inc.
Arizona Public Service
Cass County Electric Cooperative
City of Monroe
Coles-Moultrie Electric Cooperative
Dairyland Power Cooperative
Flathead Electric Cooperative, Inc.
Municipal Services Commission
Northwestern Electric Cooperative, Inc.
Otter Tail Power Company
Sacramento Municipal Utility District
Salt River Project Agricultural Improvement & Power District
San Diego Gas & Electric
Sioux Valley SW Elec Coop
Town of High Point
Warren Electric Cooperative, Inc

Demand Bidding & Buy-Back

City of Glendale
City of Milford
Connecticut Light and Power Company
Duke Energy Carolinas, LLC
Duke Energy Corporation
Duke Energy Indiana, Inc.
City of Saint Peter
Entergy Gulf States Louisiana, L.L.C.
ISO New England
Niagara Mohawk Power Corporation
PJM Interconnection, LLC
Southern California Edison (SCE)

Direct Load Control

A & N Electric Cooperative
Adams Electric Cooperative
Adams Electric Cooperative, Inc.
Adams-Columbia Electric Cooperative
Alabama Municipal Electric Authority
Alabama Power Company
Allegheny Electric Cooperative, Inc.
Ames, City of
Ashley-Chicot Electric Cooperative, Incorporated
Austin Utilities
Baltimore Gas and Electric Company
BARC Electric Coop Inc
Barnesville Municipal Electric
Bedford Rural Elec Coop, Inc
Black Hills Electric Cooperative, Inc
Blooming Prairie Public Utility Commission
Bon Homme Yankton Electric Association, Inc.
Brunswick Electric Membership Corporation
Burlington Electric Department
Butler Public Power District
Butler Rural Electric Cooperative, Inc.
Butte Electric Cooperative
C&L Electric Cooperative Corporation
Caddo Electric Cooperative, Inc.
Capital Electric Cooperative, Inc.
Carroll Electric Cooperative Corporation
Carroll Electric Membership Corporation
Cass County Electric Cooperative
Central Alabama Electric Cooperative
Central Electric Cooperative
Central Electric Cooperative, Inc.
Central Georgia Electric Membership Corp.
Central Vermont Public Service Corporation
Charles Mix Electric
Citizens' Electric Company
City of Big Stone City
City of East Grand Forks - (MN)
City of Gothenburg
City of Groton
City of Halstad
City of Hawarden City of Milford
City of Milford
City of Olivia (MN)
City of Port Angeles
City of Rock Hill
City of Roseau
City of Roseville
City of St. James

Direct Load Control (Continued)

City of Valley City
City of Vermillion
City of Wadena Electric & Water
City of Winner
Claverack REC
Clay County Electric Cooperative Corporation
Clay-Union Electric Corporation
Cleveland Electric Illuminating Co
Coles-Moultrie Electric Cooperative
Commonwealth Edison Company
Connexus Energy
Consolidated Edison Company of New York
Cooperative Light and Power
Corn Belt Energy Corporation
Corn Belt Power Cooperative
Craighead Electric Cooperative Corporation
Crow Wing Cooperative Power & Light Company
Dairyland Power Cooperative
Dakota Electric Association
Delaware Electric Cooperative, Inc.
Delmarva Power and Light Company
Dixie Electric Membership Corporation
Douglas Electric Cooperative, Inc.
Duke Energy Carolinas, LLC
Duke Energy Corporation
Duke Energy Indiana Inc
Duke Energy Kentucky, Inc.
East River Electric Power Cooperative, inc.
Elk River Municipal Utilities
Elkhorn Rural Public Power District
Emerald People's Utility District
EnergyUnited Electric Membership Corporation
Entergy New Orleans, Inc.
Excelsior Electric Membership Corporation
Fairfield Electric Cooperative Inc.
Farmers Electric Cooperative Corporation
Farmers' Electric Cooperative, Inc.
Federated Rural Electric
First Electric Cooperative Corporation
Flint Electric Membership Corporation
Florida Power & Light Company
Fort Collins Utilities
Georgia Power
Grundy Electric Cooperative, Inc.
Hawaiian Electric Company, Inc.
Haywood Electric membership Corp.
H-D Electric Cooperative, Inc
Henry County REMC
Highline Electric Association
Idaho Power Company
Illinois Rural Electric Cooperative
Indiana Michigan Power Company
Interstate Power and Light Company
Itasca-Mantrap Cooperative Electrical Association
Jackson Electric Membership Corporation
Jackson Energy Cooperative Corp - (KY)
Jefferson Energy Cooperative
Jersey Central Power & Light Co
Kansas City Power & Light Company
Kansas Gas & Electric Company
KCP&L Greater Missouri Operations Company
Kingsbury Electric Cooperative, Inc.
Lake Region Electric Cooperative
Lee County Electric Cooperative, Incorporated
Louisville Gas & Electric and Kentucky Utilities
Marshall Municipal Utilities
McLean Electric Coop
McLeod Cooperative Power Association
Mecklenburg Electric Cooperative
Menard Electric Cooperative
Metropolitan Edison Co
MidAmerican Energy Company
Midwest Electric, Inc.
Midwest Energy Cooperative
Midwest Energy, Inc.
Midwest ISO
Minnesota Valley Electric Cooperative
Minnkota Power Cooperative, Inc.
Mississippi County Electric Cooperative, Inc.
Moorhead Public Service
Mountain View Electric Association, Inc.
Municipal Commission of Boonville
Nevada Power Company
Nobles Cooperative Electric
North Arkansas Electric Cooperative, Incorporated
North Carolina Electric Membership Corp
North Central Electric Coop
Northeastern REMC
Northern Municipal Power Agency
Northern Virginia Electric Cooperative
Oahe Electric Cooperative Inc.
Ohio Edison Co
Osceola Electric Cooperative, Inc.
Otter Tail Power Company
Pacific Gas and Electric Company
PacifiCorp
Pee Dee Electric Membership Corp.
Pennsylvania Electric Co
Pennsylvania Power Co
People's Electric Cooperative
Perennial Public Power District
Piedmont Electric Membership Corporation
Pocahontas Municipal Utilities
Potomac Electric Power Company
Power Choice/ Pepco Energy Services
Prince George Electric Cooperative
Princeton Public Utilities Commission
Progress Energy Carolinas
Progress Energy Florida
Public Service Electric & Gas Company
Puget Sound Energy, Inc.
Rappahannock Electric Cooperative

Direct Load Control (Continued)

Renville-Sibley Cooperative Power Association
Rolling Hills Electric Cooperative, Inc.
Sacramento Municipal Utility District
San Diego Gas & Electric
Santee Electric Cooperative, Inc.
Shakopee Public Utilities Commission
Shelby Electric Cooperative
Shenandoah Valley Electric Cooperative
Sioux Center Municipal Electric Utility
Sioux Valley SW Elec Coop
South Central Electric Association
South Central Power Company
Southeastern Electric Cooperative, Inc.
Southern California Edison (SCE)
Southern Indiana Gas & Elec
Southern Indiana REC, Inc.
Southern Maryland Electric Cooperative, Inc.
Southwest Public Power District
Southwestern Electric Power Company
Spring Valley Public Utilities
Steuben Rural Electric Cooperative, Inc.
Sumter Electric Cooperative, Inc.
Superior Water, Light and Power Company
Tampa Electric Company
The Detroit Edison Company
The Frontier Power Company
The Midwest Electric Cooperative Corporation
The Toledo Edison Co
Town of Massena Electric Department
Tucson Electric Power
TXU Energy Retail Company LLC
Union County Electric Cooperative, Inc.
United Electric Cooperative
United Power
Virginia Electric & Power Co
Westar Energy, Inc.
Whetstone valley electric cooperative, Inc
Wiregrass Electric Cooperative, Inc.
Wisconsin Public Service Corporation
Wisconsin Power and Light Company
Woodruff Electric Cooperative Corporation
Xcel Energy
York Electric Cooperative, Inc.

Emergency Demand Response

Central Hudson Gas & Electric Corporation
City of Columbus, Ohio
Electric Reliability Council of Texas
Energy spectrum, Inc
EnerNOC, Inc
ISO New England
Kansas City Power & Light Company
Keytex Energy LLC
Manitowoc Public Utilities
Midwest ISO
Monongahela Power Co
Nebraska Public Power District
New York Independent System Operator
New York State Electric & Gas
Niagara Mohawk Power Corporation
Northern Virginia Electric Cooperative
Pacific Gas and Electric Company
Rochester Gas & Electric
Sacramento Municipal Utility District
Sierra Pacific Power Company
Southern California Edison (SCE)
Tampa Electric Company
The United Illuminating Company
West Penn Power Company

Interruptible Load

Adams Electric Cooperative
Adams Electric Cooperative, Inc.
Alabama Power Company
APN Starfirst, L.P.
Appalachian Power Company
Arkansas Electric Cooperative Corporation
Atchison-Holt Electric Coop
Austin Utilities
Baltimore Gas and Electric Company
Blooming Prairie Public Utility Commission
Board of Public Utilities, City of McPherson
Bon Homme Yankton Electric Association, Inc.
Borough of Lansdale
Brunswick Electric Membership Corporation
C&L Electric Cooperative Corporation
Carroll Electric Cooperative Corporation
Carroll Electric Membership Corporation
Central Electric Cooperative
Central Iowa Power Cooperative
Central Vermont Public Service Corporation
City of Cartersville, Georgia
City of Elroy
City of Halstad
City of Lakeland, Lakeland Electric
City of Lincoln Electric System
City of Port Angeles
City of Rock Hill
City of Saint Peter
City of Sheboygan Falls
City of Tallahassee Utilities
City Utilities of Springfield, MO
Clay Electric Cooperative, Inc.
Columbus Southern Power Company
Commonwealth Edison Company
Connecticut Light and Power Company
Connexus Energy
Consolidated Edison Company of New York
Consumers Energy Company

Interruptible Load (Continued)

Corn Belt Energy Corporation
Crow Wing Cooperative Power & Light Company
Dairyland Power Cooperative
Dakota Electric Association
Delaware Electric Cooperative, Inc.
Dixie Escalante REA Inc.
Duke Energy Carolinas, LLC
Duke Energy Corporation
Duke Energy Indiana Inc
Duke Energy Kentucky, Inc.
Elk River Municipal Utilities
EnergyUnited Electric Membership Corporation
Entergy Arkansas Inc
Entergy Gulf States Louisiana, L.L.C.
Entergy Louisiana Inc
Entergy New Orleans, Inc.
Entergy Texas, Inc.
Federated Rural Electric
First Electric Cooperative Corporation
Florida Power & Light Company
Fort Collins Utilities
Four County EMC
Georgia Power
Green Mountain Power Corporation

Hawaiian Electric Company, Inc.
Howard Greeley Rural Public Power District
Idaho Power Company
Illinois Rural Electric Cooperative
Indiana Michigan Power Company
Interstate Power and Light Company
Itasca-Mantrap Cooperative Electrical Association
JEA
Jefferson Energy Cooperative
Kansas City Power & Light Company
Kansas Gas & Electric Company
KCP&L Greater Missouri Operations Company
Kentucky Power Company
Lake Country Power
Lake Region Electric Cooperative
Lamb County Electric Cooperative
Lee County Electric Cooperative, Incorporated
Linn County Rural Electric Cooperative Association
Louisville Gas & Electric and Kentucky Utilities
Loup River Public Power District
Loup Valleys Rural Public Power District
Marshall Municipal Utilities
Mecklenburg Electric Cooperative
Menard Electric Cooperative
MidAmerican Energy Company
Midwest Energy Cooperative
Midwest Energy, Inc.
Midwest ISO
Minnesota Power, Inc.
Minnesota Valley Electric Cooperative
Mississippi County Electric Cooperative, Inc.
Mississippi Power
Moorhead Public Service
Mountain View Electric Association, Inc.
Municipal Electric Utility of the City of Cedar Falls, Iowa
New York Power Authority
Nobles Cooperative Electric
North Carolina Electric Membership Corp
Northern Virginia Electric Cooperative
NorthWestern Energy
Ocmulgee Electric Membership Corporation
Ohio Power Company
OSCEOLA ELECTRIC COOPERATIVE, INC.
Ouachita Electric Cooperative Corporation
Ozarks Electric Cooperative Corporation
Pacific Gas and Electric Company
PECO Energy Company
Prince George Electric Cooperative
Progress Energy Carolinas
Progress Energy Florida
Public Service Company of Oklahoma
Public Service Electric & Gas Company
Rappahannock Electric Cooperative
Richards Energy Group, Inc.
Sacramento Municipal Utility District
Salt River Project Agricultural Improvement & Power District
San Diego Gas & Electric
Shelby Electric Cooperative
Shenandoah Valley Electric Cooperative
South Carolina Electric & Gas Company
South Carolina Public Service Authority
South Central Arkansas Electric Cooperative, Incorporated
South Central Electric Association
South Kentucky Rural Electric Cooperative Corp
Southern California Edison (SCE)
Southern Indiana Gas & Electric Co
Southern Maryland Electric Cooperative, Inc.
Southwest Arkansas Electric Cooperative Corporation
Southwestern Electric Power Company
Spencer Municipal Utilities
Sumter Electric Cooperative, Inc.
T.I.P. Rural Electric Cooperative
Tampa Electric Company
Tennessee Valley Authority
The Detroit Edison Company
The Empire District Electric Company
The Potomac Edison Company
The Satilla Rural Electric Membership Corporation
Tucson Electric Power
Union County Electric Cooperative, Inc.
Upper Peninsula Power Corporation
Virginia Electric & Power Co
Warren Electric Cooperative, Inc
Webster Electric Cooperative
West Penn Power Company
Westar Energy, Inc.
Wheeling Power Company
Whetstone Valley Electric Cooperative, Inc

Interruptible Load (Continued)

Wisconsin Electric Power Company
Wisconsin Public Service Corporation
Wisconsin Power and Light Company
Woodruff Electric Cooperative Corporation
WPPI Energy
Xcel Energy

Load as a Capacity Resource

Arizona Public Service
Brazos Electric Power Cooperative, Inc.
Cass County Electric Cooperative
City of Radford - Electric Department
Cooperative Light and Power
EnerNOC, Inc
Idaho Power Company
Memphis Light, Gas & Water Division
Midwest ISO
New York Independent System Operator
PJM Interconnection, LLC
Public Service Company of New Mexico (PNM)
Salt River Project Agricultural Improvement & Power District
San Diego Gas & Electric
Southern California Edison (SCE)
Tampa Electric Company
Tri-County Electric Cooperative, Inc
West Penn Power Company
Wisconsin Electric Power Company
WPPI Energy

Non-spinning Reserves

California Independent System Operator
PJM Interconnection, LLC

Other

Board of Public Utilities, City of McPherson
Carroll Electric Membership Corporation
Central Electric Cooperative, Inc.
City of Ceylon
Consolidated Edison Company of New York
Consumers Energy Company
Delaware Electric Cooperative, Inc.
Eastern Maine Electric Cooperative, Inc
Eastside Power Authority
Entergy Arkansas Inc
Fairburn Utilities
ISO New England
Itasca-Mantrap Cooperative Electrical Association
Louisville Gas & Electric and Kentucky Utilities
Minnesota Valley Electric Cooperative
Mountain View Electric Association, Inc.
Nebraska Public Power District
New York Independent System Operator
Northwestern REC
Oklahoma Electric Cooperative
Orange & Rockland Utilities Inc
Puget Sound Energy, Inc.
Rockland Electric Co
Salt River Project Agricultural Improvement & Power District
Sierra Electric Cooperative, Inc.
South Carolina Electric & Gas Company
Southern California Edison (SCE)
Southwest Power Pool
Spring Valley Public Utilities
United Electric Cooperative Services, Inc.
United Power
Western Massachusetts Electric Company
Wisconsin Electric Power Company
Withlacoochee River Electric Cooperative, Inc.

Peak Time Rebate

Entergy New Orleans, Inc.
Granite State Electric Company
Grundy Electric Cooperative, Inc.
Massachusetts Electric Company
Nantucket Electric Company
OGE Energy Corporation
Oklahoma Electric Cooperative
The Narragansett Electric Company
Tri-County Electric Cooperative, Inc.

Real-Time Pricing

Alpena Power Company
Commonwealth Edison Company
Duke Energy Carolinas, LLC Duke Energy Corporation
Duke Energy Kentucky, Inc.
Entergy Arkansas Inc
Georgia Power
Gulf Power Company
Indiana Michigan Power Company
Kansas City Power & Light Company
KCP&L Greater Missouri Operations Company
Kentucky Power Company
MidAmerican Energy Company
New York State Electric & Gas
Niagara Mohawk Power Corporation
Northern Neck Electric Cooperative
Northern Virginia Electric Cooperative
OGE Energy Corporation
Otter Tail Power Company
Progress Energy Carolinas
Public Service Company of Oklahoma
Public Service Electric & Gas Company
Rochester Gas & Electric
South Carolina Public Service Authority
Southern California Edison (SCE)
Tennessee Valley Authority

Real-Time Pricing (Continued)

Upper Peninsula Power Corporation
Virginia Electric & Power Co
West Penn Power Company
Wisconsin Public Service Corporation
Xcel Energy

Regulation

ISO New England
PJM Interconnection, LLC

Spinning Reserves

Electric Reliability Council of Texas
EnerNOC, Inc
New York Independent System Operator

System Peak Response Transmission Tariff

Jefferson Energy Cooperative
Nueces Electric Cooperative
Red River Valley Rural Electric Association

Time-of-Use

A & N Electric Cooperative
Adams Electric Cooperative
Adams Electric Cooperative, Inc.
Algoma Utility Commission
Appalachian Power Company
Arizona Public Service
Bangor Hydro Electric Company
Bear Valley Electric Service
Bedford Rural Elec Coop, Inc
Bloomer Electric & Water Co
Board of Public Utilities, City of McPherson
Boscobel Municipal Utilities
Broad River Electric Cooperative, Inc.
Brodhead Water & Light Commission
Burlington Electric Department
Butler Rural Electric Cooperative Association, Inc.
Carbon Power & Light Inc
Cedarburg Light & Water Commission
Central Hudson Gas & Electric Corporation
Central Maine Power Co
Central Vermont Public Service Corporation
Chicopee Municipal Lighting Plant
City of Boulder City
City of Carlyle, Illinois
City of Carmi, Illinois
City of Crystal Falls
City of Gastonia
City of Glendale
City of Lakeland, Lakeland Electric
City of Lodi
City of Milford
City of North Saint Paul
City of Palo Alto Utilities
City of Pasadena
City of Rancho Cucamonga
City of Rock Hill
City of Roseville
City of Salem
City of Tallahassee Utilities
City of Westfield
Clark County REMC
Claverack REC
Clay Electric Cooperative, Inc.
Clintonville Utilities
Colorado Springs Utilities
Columbus Southern Power Company
Columbus Water & Light Dept.
Connecticut Light and Power Company
Consumers Energy
Cooperative Light and Power
Coosa Valley Electric Cooperative
Crawfordsville Electric Light & Power
Crow Wing Cooperative Power & Light Company
Cuba City Electric & Water Utility
Dairyland Power Cooperative
Delaware Electric Cooperative, Inc.
Delmarva Power and Light Company
Dixie Escalante REA Inc.
Duke Energy Carolinas, LLC
Duke Energy Corporation
Duke Energy Indiana Inc
Duke Energy Kentucky, Inc.
Eagle River Light & Water Commission
Eastside Power Authority
Edgecombe-Martin County Electric Membership Corp.
Empire Electric Association, Inc.
Entergy Arkansas Inc
Entergy Gulf States Louisiana, L.L.C.
Entergy Louisiana Inc
Entergy Texas, Inc.
Evansville Water & Light
Fitchburg Gas and Electric Light Company
Flathead Electric Cooperative, Inc.
Flint Electric Membership Corporation
Florence Utility Commission
Florida Power & Light Company
Florida Public Utilities Co.
Gaffney Board of Public Works
Georgia Power
Grand Haven Board of Light and Power
Grand River Dam Authority
Green Mountain Power Corporation
Groton Electric Light Dept.
Gulf Power Company
Hartford Utilities
Hawaii Electric Light Company, Inc.
Hawaiian Electric Company, Inc.
Haywood Electric membership Corp.
Hendricks County Rural Electric Membership Cooperative
High Plains Power, Inc.

Time-of-Use(Continued)

Highline Electric Association
Holy Cross Electric Assn, Inc
Hustisford Utilities
Indiana Michigan Power Company
Inter County Energy Cooperative
Interstate Power and Light Company
Itasca-Mantrap Cooperative Electrical Association
Jackson County Rural electric Membership Corporation
Jackson Electric Membership Corporation
JEA
Jefferson Energy Cooperative
Jefferson Water & Light Dept.
Jemez Mountains Electric Cooperative, Inc.
Jo-Carroll Energy, Inc.(NFP)
Juneau Utility Commission
Kansas City Power & Light Company
Kansas Gas & Electric Company
Kaukauna Utilities
KCP&L Greater Missouri Operations Company
Kentucky Power Company
Kingsport Power Company
Kissimmee Utility Authority
La Plata Electric Assn. Inc.
Lake Country Power
Lake Mills Light & Water Dept.
Linn County Rural Electric Cooperative Association
Lodi Municipal Light & Water Utility
Los Angeles Department of Water and Power
Manitowoc Public Utilities
Maui Electric Company, Limited
McLeod Cooperative Power Association
Mecklenburg Electric Cooperative
Medford Electric Utility
Memphis Light, Gas & Water Division
Menasha Electric & Water Utilities
MidAmerican Energy Company
Midwest Energy Cooperative
Mississippi Power
Mount Horeb Electric Utility
Mountain Parks Electric, Inc.
Mountain View Electric Association, Inc.
Muscoda Light & Water Utility
Nebraska Public Power District
New Glarus Light & Water Works
New Holstein Public Utility
New London Electric & Water Utility
New Richmond Municipal Electric Utility
New York State Electric & Gas
Niagara Mohawk Power Corporation
North Little Rock Electric Department
Northeastern REMC
Northern Neck Electric Cooperative
Northern Virginia Electric Cooperative
Northwestern Electric Cooperative, Inc.
NorthWestern Energy
Northwestern REC
Oconto Falls Water & Light Commission
OGE Energy Corporation
Ohio Power Company
Okefenoke Rural El Member Corp
Oklahoma Electric Cooperative
Orange & Rockland Utilities Inc
Orlando Utilities Commission
Otero County Electric Cooperative, Inc.
Otter Tail Power Company
Ozark Border Electric Cooperative
Pee Dee Electric Membership Corp.
Piedmont Electric Membership Corporation
Pioneer Electric Cooperative, Inc.
Plymouth Utilities
Potomac Electric Power Company
Poudre Valley Rural Electric Association, Inc.
Prairie du Sac Municipal Electric & Water
Progress Energy Carolinas
Progress Energy Florida
Public Service Company of New Hampshire
Public Service Company of Oklahoma
Public Service Electric & Gas Company
PUD No 1 of Klickitat County
Rappahannock Electric Cooperative
Reedsburg Utility Commission
Rice Lake Utilities
Richland Center Electric Utility
Richmond Power and Light
River Falls Municipal Utility
Riverside Public Utilities
Rochester Gas & Electric
Rockland Electric Co
Sacramento Municipal Utility District
Salt River Project Agricultural Improvement & Power District
Sangre de Cristo Electric Association
Sierra Electric Cooperative, Inc.
Slinger Utilities
Snohomish County PUD No 1
South Carolina Electric & Gas Company
South Carolina Public Service Authority
South Central Electric Association
South Kentucky Rural Electric Cooperative Corp
South Mississippi Electric Power Association
Southwestern Electric Power Company
Steuben Rural Electric Cooperative, Inc.
Stoughton Electric Utility
Sturgeon Bay Utilities
Sun Prairie Water & Light Commission
Superior Water, Light and Power Company
Tampa Electric Company
Tennessee Valley Authority
The Detroit Edison Company
The Empire District Electric Company
The Satilla Rural Electric Membership Corporation
Tri-County Electric Cooperative, Inc
Tucson Electric Power

Time-of-Use(Continued)

Turlock Irrigation District
Two Rivers Water & Light Utility
TXU Energy Retail Company LLC
Union Electric Company
United Electric Cooperative Services, Inc.
United Power
Valley Rural Electric Cooperative, Inc.
Village of Stratford
Virginia Electric & Power Co
Wake Electric
Waterloo Water & Light Commission
Waunakee Water & Light Commission
Waupun Utilities
Waverly Municipal Elec Utility
Westar Energy, Inc.
Westby Municipal Electric Utility
Western Indiana Energy REMC
Western Massachusetts Electric Company
Wheatland Rural Electric Cooperative
Wheeling Power Company
Wisconsin Public Service Corporation
Wisconsin Power and Light Company
WPPI Energy
Xcel Energy

APPENDIX G: DATA FOR FIGURES IN REPORT

Advanced Metering

Data supporting Figure 2-1

Estimated advanced metering penetration nationwide in 2006, 2008, 2010, and 2012 FERC Surveys

Year	Advanced Metering
2006	0.7%
2008	4.7%
2010	8.7%
2012	22.9%

Data supporting Figure 2-2

Estimated advanced metering penetration nationwide reported in 2006, 2008, 2010 and 2012 FERC Surveys

Region	2006 FERC Survey	2008 FERC Survey	2010 FERC Survey	2012 FERC Survey
ASCC	0.0%	0.0%	1.2%	0.0%
FRCC	0.1%	10.4%	5.0%	32.5%
Hawaii	0.0%	1.6%	2.1%	0.2%
MRO	0.6%	3.7%	15.3%	14.6%
NPCC	0.1%	0.3%	0.7%	5.3%
RFC	0.4%	5.1%	6.7%	10.4%
SERC	1.2%	5.8%	8.0%	22.0%
SPP	3.0%	5.8%	8.9%	15.2%
TRE	0.7%	9.0%	13.4%	38.6%
WECC	0.5%	2.1%	14.1%	42.4%
United States	0.7%	4.7%	8.7%	22.8%

Data supporting Figure 2-3

Estimated advanced metering penetration by type of entity in 2006, 2008, 2010, and 2012 FERC Surveys

Ownership	2006 FERC Survey	2008 FERC Survey	2010 FERC Survey	2012 FERC Survey
Cooperatives	3.8%	16.4%	24.7%	30.8%
Political Subdivision	0.1%	2.2%	20.3%	29.4%
Investor-owned Utility	0.2%	2.7%	6.6%	25.0%
Municipal Entities	0.3%	4.9%	3.6%	12.4%
Federal and State Utility	0.2%	1.1%	0.7%	3.6%
Overall Average	0.7%	4.7%	8.7%	22.8%

Data supporting Figure 2-4
Reported numbers of customers and communication methods for advanced metering by customer class

Customer Sector	Internet	Bills	Display Unit
Communications Vehicles to Residential Customers (n = 17,365,353)	92% (n = 15,961,296)	7% (n = 1,297,960)	1% (n = 106,097)
Communications Vehicles to Nonresidential Customers (n = 1,587,655)	91% (n = 1,448,672)	9% (n = 136,754)	0% (n = 2,229)
Communications Vehicles to Other Customers (n = 125,695)	93% (n = 116,922)	7% (n = 8,769)	0% (n = 4)

Demand Response

Data supporting Figure 3-1
Total reported potential peak reduction in the 2006 through 2012 FERC Surveys

FERC Survey Year	Total reported potential peak reduction (MW)
2006 FERC Survey	29,653
2008 FERC Survey	37,335
2010 FERC Survey	53,062
2012 FERC Survey	66,351

Data supporting Figure 3-2
Reported potential peak reduction by customer class in 2006, 2008, 2010, and 2012 FERC Surveys (MW)

FERC Survey Year	Commercial & Industrial	Residential	Wholesale	Other	Total
2006 FERC Survey	14,362	5,803	8,899	589	29,653
2008 FERC Survey	17,434	6,056	12,656	1,190	37,335
2010 FERC Survey	21,405	7,189	22,884	1,584	53,062
2012 FERC Survey	28,088	8,134	28,807	1,321	66,351

Data supporting Figure 3-3

Reported potential peak reduction by Independent System Operators and Regional Transmission Operators in 2010 and. 2012 (MW)

ISO/RTO	CAISO		ERCOT		ISO-NE		MISO		NY-ISO		PJM		SPP	
Program Type	2010	2012	2010	2012	2010	2012	2010	2012	2010	2012	2010	2012	2010	2012
Demand Bidding & Buy-Back	120	0	0	0	91	202	210	0	0	37	2,635	2,252	0	0
Direct Load Control	0	0	0	0	0	0	60	0	0	0	0	0	0	0
Emergency Demand Response	0	0	237	420	2,092	1,029	230	2,149	972	197	7,295	0	0	0
Load as a Capacity Resource	0	0	0	0	0	0	4,800	7,380	2,061	1,976	0	11,821	0	0
Non-spinning Reserves	0	120	0	0	0	0	0	0	0		118	54	0	0
Other	0	0		0	0	0	0	0	258	37	0	0	1,385	1,514
Regulation	0	0	10	0	0	0	0	0	0	0	0	0	0	0
Spinning Reserves	0	0	1,062	1,150	0	0	0	0	0	0	406	0	0	0

Data supporting Figure 3-4

Reported potential peak reduction by region and customer class for the 2010 and 2012 FERC Survey

Region	Commercial & Industrial		Residential		Wholesale		Other		Total	
	2010	2012	2010	2012	2010	2012	2010	2012	2010	2012
FRCC	1,310	1,952	1,765	1,804	15	15	68	35	3,158	3,807
MRO	3,320	3,264	1,806	1,540	4,045	5,115	315	251	9,485	10,170
NPCC	1,490	719	90	34	4,649	2,972	0	0	6,228	3,725
RFC	5,267	7,476	1,139	2,100	9,199	14,677	259	128	15,864	24,381
SERC	6,451	8,672	798	1,046	1,733	2,881	172	210	9,154	12,809
SPP	1,404	2,667	79	220	1,502	1,456	141	126	3,126	4,469
TRE	72	4	123	66	1,312	1,572	3	0	1,510	1,642
WECC	2,062	3,287	1,369	1,307	430	120	626	571	4,487	5,284
Other	29	48	20	17	0	0	0	0	49	65
Total	21,405	28,088	7,189	8,134	22,884	28,807	1,584	1,321	53,062	66,351

Data supporting Figure 3-5

Reported potential peak reduction in by type of program type and by customer class in 2012 FERC Survey

Type of Program	Commercial & Industrial	Residential	Wholesale	Other	Total
Critical Peak Pricing	261	54	6	0	321
Critical Peak Pricing with Load Control	129	2	0	15	147
Demand Bidding & Buy-Back	139	0	3,927	0	4,066
Direct Load Control	1,638	6,940	666	534	9,777
Emergency Demand Response	494	110	3,734	0	4,339
Interruptible Load	14,268	45	685	649	15,647
Load as a Capacity Resource	2,649	77	16,600	0	19,327
Non-spinning Reserves	0	0	174	0	174
Other	105	40	1,076	54	1,276
Peak Time Rebate	58	1	0	0	59
Real-Time Pricing	1,868	6	0	0	1,874
Regulation	0	0	0	0	0
Spinning Reserves	40	0	1,150	0	1,190
System Peak Response Transmission Tariff	12	0	0	0	13
Time-of-Use	6,425	858	789	69	8,141
Total	28,088	8,134	28,807	1,321	66,351

Data supporting Figure 3-6 and 3-7

Reported potential and actual 2012 peak reduction by demand response resources by region

Region	Potential Peak Reduction	Actual Peak Reduction	
	2012	**2010**	**2012**
FRCC	3,807	957	966
MRO	10,170	2,462	2,709
NPCC	3,725	2,497	3,151
RFC	24,381	2,051	3,651
SERC	12,809	3,086	3,520
SPP	4,469	1,466	1,863
TRE	1,642	422	1,470
WECC	5,284	2,667	2,870
Other	65	352	55
Total	66,351	15,980	20,256

Data supporting Figure 3-8

Estimated potential peak reduction by region and customer class in 2010 and 2012

Region	Commercial & Industrial		Residential		Wholesale		Other		Total	
	2010	2012	2010	2012	2010	2012	2010	2012	2010	2012
FRCC	1,333	1,974	1,795	1,845	15	15	73	52	3,216	3,887
MRO	3,932	4,912	2,102	2,232	4,045	5,115	339	360	10,418	12,619
NPCC	1,954	739	98	91	4,649	2,972	173	8	6,875	3,811
RFC	6,334	7,882	1,427	2,373	9,199	14,677	371	424	17,331	25,356
SERC	7,005	9,331	1,575	1,419	1,733	2,881	208	301	10,521	13,932
SPP	1,572	2,915	80	236	1,502	1,456	154	133	3,307	4,740
TRE	113	262	134	143	1,312	1,572	53	5	1,612	1,981
WECC	2,344	3,208	1,581	1,254	430	120	626	639	4,981	5,221
Other	53	85	25	22	78	0	0	0	0	107
Total	24,640	31,310	8,817	9,616	22,884	28,807	1,998	1,921	58,339	71,654

Data supporting Figure 3.9

Estimated potential peak reduction by entity type and customer class in 2010 and 2012

Ownership	Residential		Commercial & Industrial		Other Retail		Wholesale		Total	
	2010	2012	2010	2012	2010	2012	2010	2012	2010	2012
Cooperative Entities	2,836	2,623	3,726	2,320	855	657	1,420	1,231	8,837	6,830
Federal & State	17	42	1,104	4,694	50	48	920	1,910	2,091	6,694
Investor-Owned Utilities	5,433	6,180	17,634	20,331	827	850	0	116	23,894	27,476
Municipal Entities	530	489	922	1,474	25	31	11	62	1,488	2,056
RTO/ISO	0	0	0	0	0	0	20,533	25,489	20,533	25,489
Retail Power Marketers	0	65	961	0	241	0	0	0	1,202	65
Other	0	217	0	2,490	0	335	0	0	0	3,043
Total	8,816	9,616	24,347	31,310	1,998	1,921	22,884	28,807	58,045	71,654

Data supporting Figure 3-10

Number of entities reporting interruptible/curtailable rates by region and type of entity in 2010 and 2012

Region	Cooperative Entities		Federal and State		Investor-Owned Utilities		Municipal Entities		Other		Total	
	2010	2012	2010	2012	2010	2012	2010	2012	2010	2012	2010	2012
FRCC	3	3	0	0	3	3	4	3	0	0	10	9
MRO	26	18	0	0	6	9	13	9	2	5	47	41
NPCC	0	0	0	1	6	4	1	0	1	0	8	5
RFC	10	6	0	0	22	20	2	2	1	3	35	31
SERC	33	27	2	2	10	13	4	2	0	0	49	44
SPP	10	5	0	0	7	8	3	3	0	0	20	16
TRE	2	0	0	0	0	0	0	0	1	0	3	0
WECC	3	2	0	0	6	6	1	3	1	1	11	12
Total	87	61	2	3	60	63	28	22	6	9	183	158

Data supporting Figure 3-11

Reported number of customers enrolled in direct load control programs by region and type of entity in 2010 and 2012

Region	Cooperative Entities		Federal and State		Investor- Owned Utilities		Municipal Entities		Other		Total	
	2010	2012	2010	2012	2010	2012	2010	2012	2010	2012	2010	2012
FRCC	60,588	62,363	0	0	1,247,228	1,273,398	0	0	0	0	1,307,816	1,335,761
MRO	406,632	311,763	2,365	0	507,152	621,613	48,849	31,454	0	21,899	964,998	986,729
NPCC	6,261	645	0	0	39,634	48,630	32,660	2,739	0	0	78,555	52,014
RFC	294,278	105,646	0	0	1,203,367	1,470,728	2,270	2,050	0	7	1,499,915	1,578,431
SERC	421,625	285,054	0	0	347,748	525,778	29,577	3,000	0	0	798,950	813,832
SPP	13,119	8,220	0	0	35,479	87,331		0	0	1,869	48,598	97,420
TRE		0	0	0		0	85,000	0	171	11,500	85,171	11,500
WECC	4,602	5,457	0	0	821,610	885,822	6,872	10,362	0	1,526	833,084	903,167
Total	1,207,105	779,148	2,365	0	4,202,218	4,913,300	205,228	49,605	171	36,801	5,617,087	5,778,854

Estimated total number of customers

FRCC	MRO	NPCC	RFC	SERC	SPP	TRE	WECC	Other
9,184,587	8,120,487	20,962,205	35,925,110	35,739,376	6,825,542	10,255,206	29,250,286	817,392

Data supporting Figure 3-12
Number of entities reporting residential time-of-use rates by region and type of entity in 2010 and 2012

Region	Cooperative Entities		Federal and State		Investor- Owned Utilities		Municipal Entities		Other		Total	
	2010	2012	2010	2012	2010	2012	2010	2012	2010	2012	2010	2012
FRCC	2	1	0	0	2	2	3	3	0	0	7	6
MRO	7	7	0	0	6	7	34	37	0	1	47	52
NPCC	3	1	1	0	7	11	3	3	3	0	17	15
RFC	9	9	0	0	9	13	1	2	0	0	19	24
SERC	12	13	1	1	8	9	0	1	0	0	21	24
SPP	3	2	0	0	2	3	0	0	0	0	5	5
TRE	1	0	0	0	0	0	0	0	0	1	1	1
WECC	16	15	0	0	4	2	4	6	3	1	27	24
Total	53	48	2	1	38	47	45	52	6	3	144	151

Data supporting Figure 3-13
Reported number of residential customers enrolled in time-of-use rate programs by region and type of entity in 2010 and 2012

Region	Cooperative Entities		Federal and State		Investor- Owned Utilities		Municipal Entities		Other		Total	
	2010	2012	2010	2012	2010	2012	2010	2012	2010	2012	2010	2012
FRCC	40	0	0	0	249	196	206	2,006	0	0	495	2,202
MRO	1,546	18,533	0	0	20,387	25,704	284	284	0	7,506	22,217	52,027
NPCC	63	36	0	0	148,706	168,248	10,152	2,073	148	0	159,069	170,357
RFC	1,521	1,420	0	0	138,910	953,035	0	2	0	0	140,431	954,457
SERC	3,289	3,230	5	5	33,301	46,986	0	124	0	0	36,595	50,345
SPP	15	46,302	0	0	1,452	2,717	0	0	0	0	1,467	49,019
TRE	8	0	0	0	0	0	0	0	0	4,000	8	4,000
WECC	237,187	12,154	0	0	498,477	529,428	2,388	4,249	0	232,201	738,052	778,032
Total	243,669	81,675	5	5	841,482	1,726,314	13,030	8,738	148	243,707	1,098,334	2,060,439

Data supporting Figure 3-14

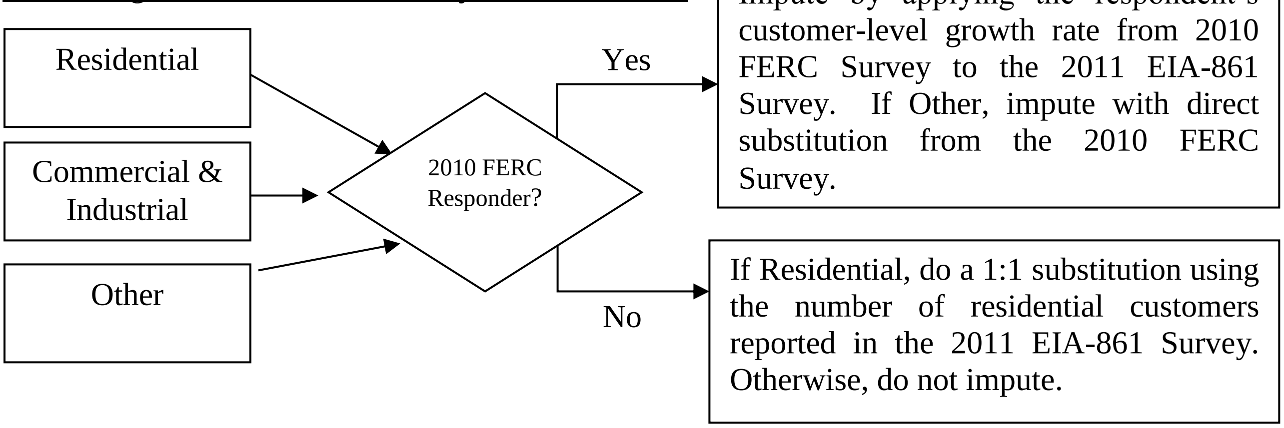
Number of entities reporting retail real-time pricing by region and type of entity in 2010 and 2012

Region	Cooperative Entities		Federal and State		Investor-Owned Utilities		Municipal Entities		Other		Total	
	2010	2012	2010	2012	2010	2012	2010	2012	2010	2012	2010	2012
FRCC	0	0	0	0	0	5	0	0	0	0	0	5
MRO	0	0	0	0	4	3	0	0	0	0	4	3
NPCC	1	0	0	0	2	8	0	0	0	0	3	8
RFC	0	0	0	2	7	5	0	0	0	0	7	7
SERC	0	0	1	0	3	4	0	0	1	0	5	4
SPP	1	0	0	0	4	0	0	0	0	0	5	0
TRE	0	0	0	0	0	0	0	0	0	0	0	0
WECC	0	0	0	0	1	1	0	0	0	0	1	1
Total	2	0	1	2	21	26	0	0	1	0	25	28

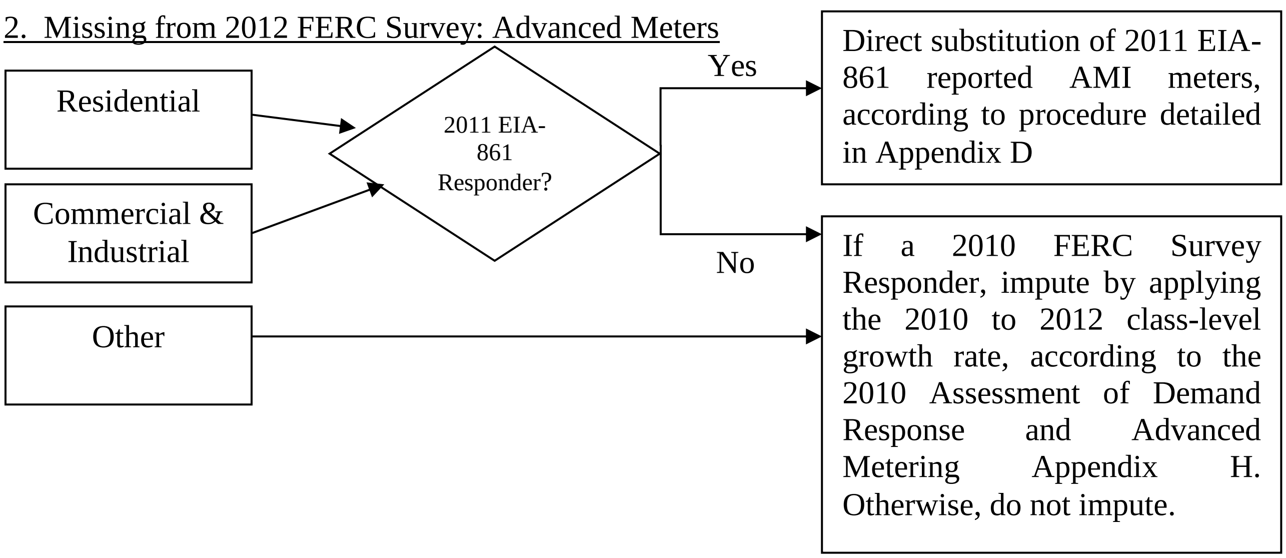
APPENDIX H: ADJUSTMENT METHODOLOGY FOR FERC-731 SURVEY

The following four flow charts summarize the estimation process used for the 2012 FERC Survey to assign estimated values for entities that did not respond to four key FERC Survey fields: total meters, advanced meters, total customers, and potential peak load reduction. The 2012 estimation process utilized data from the initial 2011 EIA-861 Survey, along with responses from the 2010 FERC Survey. In cases when an imputation could not be used, the universe-level estimates are not accounting for those cases.

1. Missing from 2012 FERC Survey: Total Meters[153]

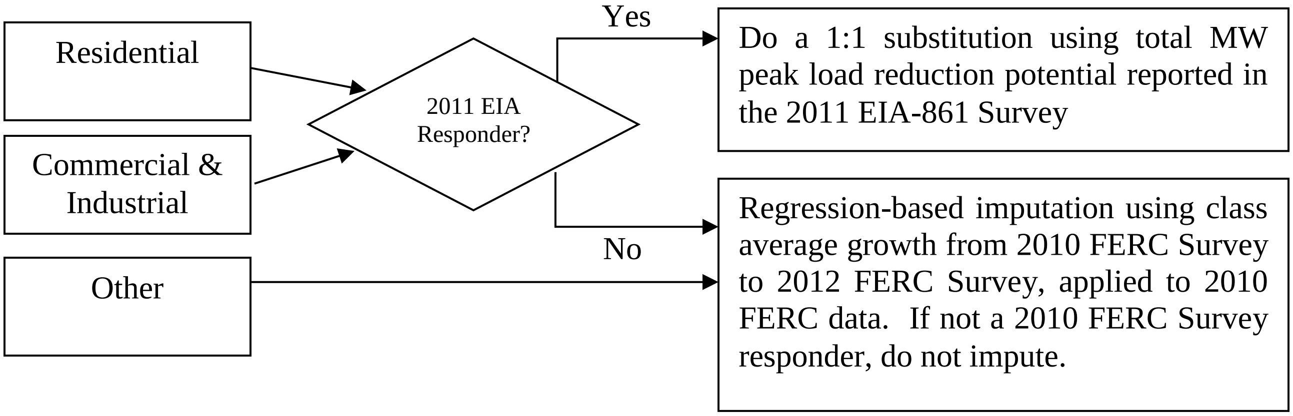


2. Missing from 2012 FERC Survey: Advanced Meters

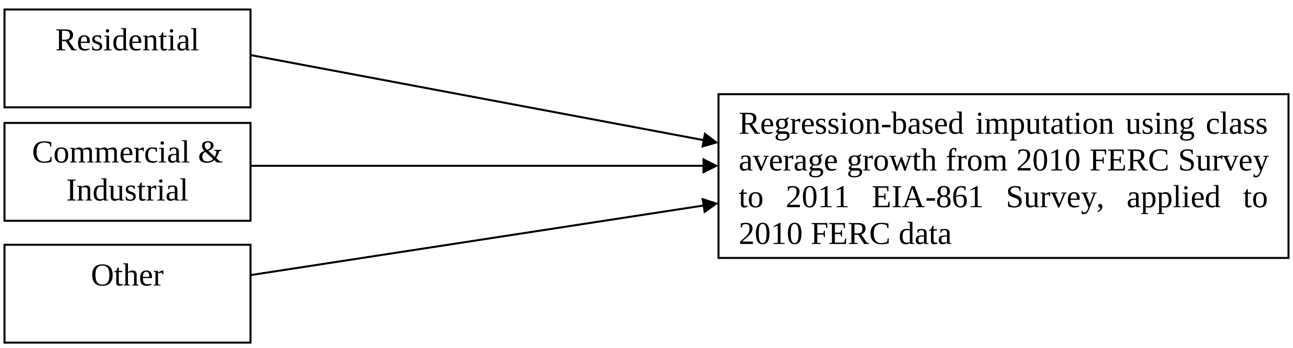


[153] Total meters for the commercial and industrial sectors did not have a strong enough correlation with total customers to justify direct imputation of customers from either the EIA-861 or 2010 FERC Survey, when total meters were not provided by the respondent.

3. Missing from 2012 FERC Survey: Potential Peak Reduction



4. Missing from 2012 FERC Survey: Total Customers



Self-Selection Assessment Subsample

The FERC Staff determined that the 2012 FERC Survey, to adhere with its Congressional directive, should collect or estimate information on all entities that provide electric power and demand response to customers in the U.S. However, the FERC Survey is voluntary, and essentially a census of respondents to the EIA-861 Survey, with the addition of Regional Transmission Operators (RTOs), Independent System Operators (ISOs), and curtailment service providers. As such, there is inherent risk for self-selection bias; for example, some entities may be more likely to respond to the FERC Survey if they have already deployed advanced meters or demand response programs, and these are key measures of the survey.

Since the propensity to respond may be related to key measures in the FERC Survey, OMB directed the Commission to assess the potential for self-selection bias in the FERC Survey, as compared to traditional statistical sampling methods. As in previous survey years, the FERC staff prepared a "bias assessment sample," or a statistical subsample from the full survey population. This section of the report describes the "bias assessment sample" design, and compares the estimates derived from the full dataset with the corresponding estimates produced from the bias assessment sample. If the corresponding estimates are within an acceptable margin of error, it supports the hypothesis that a census of the target population achieves as reliable estimates as a traditional statistical sample. However, significant differences in the corresponding estimates would indicate a significant risk for self-selection bias in the FERC Survey.

Assessment of Past Designs

The designs for 2006 and 2008 bias assessment samples utilize known relationships of advanced metering penetration with region, utility type, and utility size. Although curtailment service providers and generation & transmission entities do not provide retail electricity and have no advanced meters associated with them, they are unique and important respondents to the survey, especially with respect to demand response data, so selecting these respondents into the sample with certainty ensures they would be accounted for. The 2010 bias assessment sample was very similar to those constructed in 2006 and 2008, except for utilizing ratio estimation rather than simple random sampling. This change improved the sampling efficiency, but added complexity to the sample construction process.

2012 Self-Selection Bias Assessment Design

DNV KEMA maintained the same basic design used in 2006, 2008, and 2010, with some modifications. Key features of the design are as follows:

- Entities were stratified by state, ownership type, and size category (small, medium, large, or other). In 2010, entities were stratified by NERC region rather than state.
- Within strata, units were selected either with certainty or probability proportionate to size (PPS). Entities were selected with certainty if they fell in the "large" size category or they did not have a number of customers served for the state listed in the EIA-861 Survey. Entities were selected PPS within the strata defined as above, with proportional allocation of a target sample size of 750 among the entities in the various strata.
- The total sample size obtained was 797 EIA utility ID/state code combinations. Some entities were included in the sample for more than one state, so the number of unique EIA utility IDs was 727.

The switch to using state instead of NERC region for the geographic stratification component was based on the addition of state-level estimates in the 2010 FERC Survey, as well as the availability of state-level customer data in the EIA-861 Survey, but not by NERC. This modification resulted in more strata, and fewer sample cases per strata, but better state-level coverage overall.

The 2012 bias assessment sample design also selects more entities with certainty; all large utilities and all entities without a listed number of customers served in a state were included in the sample. Large utilities were selected with certainty because they tend to have a disproportionally large contribution towards total advanced metering and demand response estimates. Entities without an assigned number of customers were included with certainty because without a measure of size to use in the sample selection, there was no other way to include them without using a different sample design; this also helped minimize overall sampling complexity and include respondents such as curtailment service providers.

No special follow-up measures beyond that of the full mail-out sample was used in 2012. All entities, whether in the sample or not, were subject to a follow-up based on their expected contribution in the survey population.

Survey Response Rates

Entity Type	Advanced Metering Response Rate	DR Response Rate
Cooperatively Owned Utility	53%	25%
Curtailment Service Provider	24%	24%
Federal Utility	63%	13%
Investor-Owned Utility	78%	64%
Municipal Power Agency	58%	0%
Municipally Owned Utility	70%	19%
Political Subdivision	44%	12%
Retail Power Marketer	20%	4%
State Utility	35%	12%
Generation and Transmission	78%	0%
Wholesale Power Marketer	19%	0%

Self-Selection Bias Assessment

The analysis of the FERC Survey subsample is geared towards determining whether a census sample is necessary for determining reliable results for the key advanced metering and demand response measures collected in the FERC Survey. The subsample versus full-sample tabulated results for the following tables are given below:

- Estimated Advanced Metering Penetration by NERC Region and Entity Type
- Estimated Potential Peak Reduction by NERC Region and Retail Customer Sector

Both tables use extrapolations to account for the full survey universe. The full-sample table is taken directly from **Appendix G** and the subsample extrapolation uses sampling weights with a ratio adjustment to account for nonresponse.

Estimated Advanced Metering Penetration by NERC Region and Entity Type - Full-Sample Analysis

NERC Region	Cooperatively Owned Utilities	Political Subdivisions	Investor-Owned Utilities	Municipally Owned Utilities	Federal and State Utilities	Overall
FRCC	14%	0%	38%	14%	0%	32%
MRO	33%	4%	10%	4%	45%	15%
NPCC	20%	0%	7%	5%	0%	5%
RFC	36%	0%	10%	5%	1%	10%
SERC	36%	0%	19%	11%	1%	22%
SPP	29%	5%	14%	2%	91%	15%
TRE	17%	0%	72%	24%	0%	39%
WECC	26%	36%	48%	18%	23%	42%
Other	0%	0%	0%	5%	0%	2%
Overall	31%	29%	25%	12%	4%	23%

Estimated Advanced Metering Penetration by NERC Region and Entity Type - Subsample Analysis

NERC Region	Cooperatively Owned Utilities	Political Subdivisions	Investor-Owned Utilities	Municipally Owned Utilities	Federal and State Utilities	Overall
FRCC	30%	0%	38%	11%	0%	33%
MRO	44%	9%	18%	0%	78%	18%
NPCC	48%	0%	6%	0%	0%	6%
RFC	25%	0%	9%	1%	1%	9%
SERC	58%	0%	0%	21%	2%	16%
SPP	37%	0%	15%	0%	91%	17%
TRE	28%	0%	74%	8%	0%	58%
WECC	16%	35%	61%	46%	100%	57%
Other	0%	0%	3%	0%	0%	3%
Overall	46%	33%	23%	24%	12%	26%

The subsample analysis results for the chosen advanced metering table shows that overall, the subsample performed well, with only a 3 percent difference in overall advanced metering penetration in the U.S. and was only 2 percentage points different for investor-owned utilities. Similarly, the results are extremely comparable for the NERC region marginal totals. The penetration estimate for RFC, for example was 2 percentage points different for the full sample and the subsample, and was even closer for NPCC. However, it is clear that abandoning the census in favor for a sample would lead to self-selection bias for cooperatives and municipally owned utilities, and for certain regions, as suggested by moderate pairwise differences for MRO.

Estimated Potential Peak Reduction by NERC Region and Retail Customer Sector – Full Sample

Region	Commercial & Industrial	Residential	Other	Total
FRCC	1,974	1,845	52	3,872
MRO	4,912	2,232	360	7,504
NPCC	739	91	8	839
RFC	7,882	2,373	424	10,680
SERC	9,331	1,419	301	11,051
SPP	2,915	236	133	3,284
TRE	262	143	5	409
WECC	3,208	1,254	639	5,101
Other	85	22	0	107
Total	31,310	9,616	1,921	42,847

Estimated Potential Peak Reduction by NERC Region and Retail Customer Sector - Subsample

Region	Commercial & Industrial	Residential	Other	Total
FRCC	1,952	1,804	35	3,792
MRO	3,754	1,662	94	5,511
NPCC	733	23	0	756
RFC	11,642	3,481	128	15,251
SERC	10,251	1,830	128	12,209
SPP	4,834	414	556	5,804
TRE	29	737	0	766
WECC	3,658	1,565	2,430	7,653
Other	47	19	0	65
Total	36,900	11,535	3,371	51,807

The analysis results for demand response suggest that utilizing a statistical sample instead of a census would lead to biased results. Unlike the advanced metering assessment, which shows above that reliable results are achievable through aggregating the data by one categorical variable, the demand response results show that most of the tabulations have pairwise differences of 20 percent or more. It is therefore advisable to continue using a census of the survey universe rather than using a statistical sample to maintain reliable survey estimates for demand response.

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