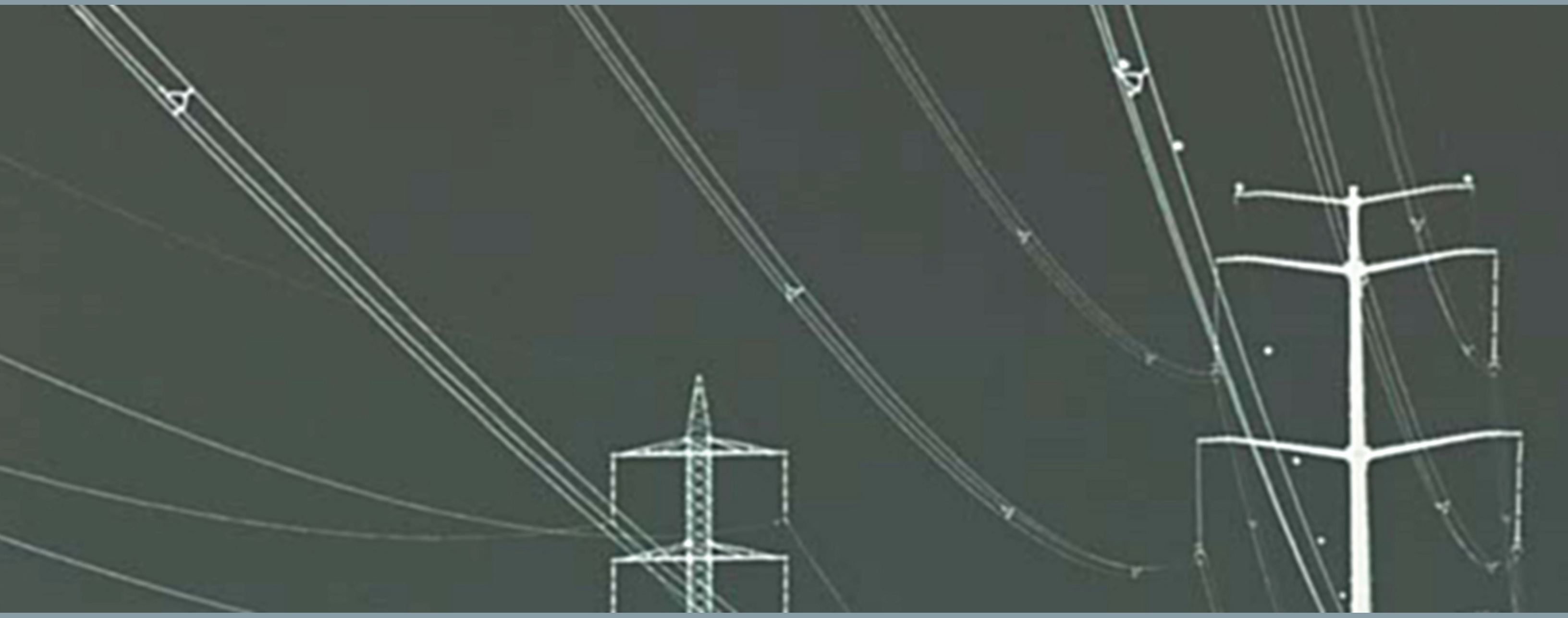
Demand Response and Smart Metering Policy Actions Since the Energy Policy Act of 2005:

A Summary for State Officials



Prepared by the U.S. Demand Response Coordinating Committee

for

The National Council on Electricity Policy

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The National Council on Electricity Policy Electric Transmission Series:

- *Electricity Transmission: A Primer* (June 2004)
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- *Demand Response and Smart Metering Policy Actions Since the Energy Policy Act of 2005: A Summary for State Officials* (November 2008)
- *Examining Alternatives to Electric Transmission: A Guide for State Officials* (to be released in 2008)
- *The Smart Grid: Policy and Practical Essentials for State Officials* (to be released in early 2009)

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National Council on Electricity Policy Member Organizations

NATIONAL COUNCIL ON ELECTRICITY POLICY

The National Council on Electricity Policy (National Council) is a unique venture between the National Association of Regulatory Utility Commissioners (NARUC), the National Association of State Energy Officials (NASEO), the National Conference of State Legislatures (NCSL), National Association of Clean Air Agencies (NACAA) and the National Governors Association (NGA). The National Council also includes participation by the Federal Energy Regulatory Commission (FERC), U.S. Department of Energy (DOE), and the U.S. Environment Protection Agency (EPA). Established in 1994, the National Council enables better coordination between federal and state entities responsible for electricity policy and programs. Our members understand that improved intrastate, regional and federal coordination can result in more informed electricity policy decisions.

NASEO National Association of State Energy Officials ENERGY'S WASHINGTON VOICE

The National Association of State Energy Officials (NASEO) is the only nonprofit organization whose membership includes the Governor-designated energy officials from each state and territory. The organization was created to improve the effectiveness and quality of state energy programs and policies, provide policy input and analysis where requested, share successes among the states, and to be a repository of information on issues of particular concern to the states and all their citizens.

NACAA national association of clean air agencies

The National Association of Clean Air Agencies (NACAA) represents air pollution control agencies in 53 states and territories and over 165 major metropolitan areas across the United States. State and local air pollution control officials formed NACAA (formerly STAPPA/ALAPCO) over 30 years ago to improve their effectiveness as managers of air quality programs. The associations serve to encourage the exchange of information among air pollution control officials, to enhance communication and cooperation among federal, state, and local regulatory agencies, and to promote good management of our air resources.

National Association of Regulatory Utility Commissioners is the association that represents State public service commissioners who regulate essential utility services, such as electricity, gas, telecommunications, water, and transportation. As regulators, our members are charged with protecting the public and ensuring that rates charged by regulated utilities are fair, just, and reasonable.

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The National Governors Association Center for Best Practices develops innovative solutions to today's most pressing public policy challenges including analysis of state and federal policies affecting environmental protection, air quality and greenhouse gases, energy infrastructure, energy efficiency and renewable energy.

NCSL

The National Conference of State Legislatures (NCSL) is the bipartisan organization that serves the legislators and staffs of the states, commonwealths and territories. NCSL provides research, technical assistance and opportunities for policymakers to exchange ideas on the most pressing state issues and is an effective and respected advocate for the interests of the states in the American federal system.

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Acronyms Used in This Report

AMI = Advanced Metering Infrastructure

CAISO = California ISO

C&I = Commercial and Industrial

DSM = Demand-Side Management

EPACT = Energy Policy Act

EPS = Energy Efficiency Portfolio Standard

ERCOT = Electric Reliability Council of Texas

FERC = Federal Energy Regulatory Commission

GHG = Greenhouse Gas

IRP = Integrated Resource Plan

ISO = Independent System Operator

M&V = Measurement and Verification

NOPR = Notice of Proposed Rulemaking

NYISO = New York ISO

PHEV = Plug-in Hybrid Electric Vehicle

PJM = PJM Interconnection, the RTO in the Mid-Atlantic region

PURPA = Public Utility Regulatory Policies Act

RFP = Request for Proposals

RPS = Renewable Energy Portfolio Standard

RTO = Regional Transmission Organization

RTP = Real-Time Pricing

SPP = Southwest Power Pool, the RTO for the southwestern region of the US

TOU = Time of Use

Overview

This report represents a review of policy developments on demand response and other related areas such as smart meters and smart grid. It has been prepared by the Demand Response Coordinating Committee (DRCC) for the National Council on Electricity Policy (NCEP). The report focuses on State and Federal policy developments during the period from 2005 to mid-year 2008. It is an attempt to catalogue information on policy developments at both the federal and state level, both in the legislative and regulatory arenas.

A special focus of the report is on State implementation of the demand response and smart metering provisions—Section 1252—of the Energy Policy Act of 2005 (EPACT).

Regarding the report's methodology and scope:

- This report is based on the best public information that was available as of August 2008 and not in-depth state-by-state research. Accordingly, and because of the rapid pace of policy developments in this area, this report may not contain all relevant policy developments.
- It is designed to summarize policy developments and not provide opinion or commentary. It includes neither analysis nor predictions regarding potential outcomes of policy developments.
- It describes policy developments on energy efficiency, renewable energy, or other areas only when they directly mention demand response, smart grid, smart meters, or other subjects directly in the area of demand response. Accordingly there may have been policy developments in those other areas (or in other areas such as state facilities, budgeting or tax policy) that can have an impact on demand response, Advanced Metering Infrastructure (AMI) and/or smart grid that are not captured by this report.
- The process of developing the report had three stages of research. The first stage consisted of reviewing the DRCC's archive of demand response policy and legislative activity. The next step was to revisit the source and review the documentation of the known activity—mostly regulatory proceedings and legislation—to determine whether there had been any additional developments. The final stage was to investigate any leads, discovered through the earlier steps of research to identify any policy or legislative activity previously unknown by the DRCC.

This report demonstrates that a substantial amount of policymaking related to demand response has happened recently or is presently underway.

At the federal level, Congress has stated its intention that demand response be incorporated into the nation's electricity system from both a policy and business perspective. Congress has also taken several specific steps to make that happen and it has recognized that demand response and its enabling technologies are key ingredients to the development of a smart grid. At the same time, Congress has not yet moved to use tax policy and mandates to stimulate the growth of demand response in a way similar to what it has done in the past for renewable energy and traditional energy efficiency. Elsewhere at the federal level, however, federal regulators have used their jurisdiction over wholesale power and regional markets to directly require development and deployment of demand response.

At the State level, this report reflects the great diversity of approaches and the many levels of activity underway in the states. Some of that activity has been undertaken pursuant to Congressional direction such as Section 1252 of EPACT but much has also been activity initiated on a state's own initiative. The other fact that is reinforced by this report is the significant role of states in demand response, given that much demand response involves modification of retail rates and approval of utility infrastructure investments, each of which are subject to state jurisdiction.

Table A summarizes the State policy activity described in this report. Specifically, the table indicates with a check mark ("✓") which states have taken some regulatory or legislative action on demand response, smart meters, and/or the smart grid. It also shows which states have initiated and completed regulatory consideration of PURPA Standard 14 on time-based metering and demand response (Section 1252 of EPACT 2005).

Table A: Summary Table of Demand Response Policy Developments

	Policy					
	Demand Response		Smart Meter/ Smart Grid			
State	Regulatory	Legislative	Regulatory	Legislative	Initiated Regulatory Consideration of EPACT 1252	Completed Regulatory Consideration of EPACT 1252
Alabama					√	√
Alaska					√	√
Arizona					√	√
Arkansas	√				√	√
California	√		√	√		
Colorado	√	√			√	√
Connecticut	√	√	√	√		
Delaware	√		√		√	√
District of Columbia	√		√		√	
Florida	√	√	√		√	√
Georgia	√				√	√
Hawaii						
Idaho	√	√	√		√	√
Illinois		√	√		√	√
Indiana	√				√	√
Iowa	√	√			√	√
Kansas	√	√	√		√	√
Kentucky	√	√			√	√
Louisiana					√	√
Maine	√	√				
Maryland	√	√	√	√	√	
Massachusetts	√	√		√		
Michigan	√	√	√		√	√
Minnesota	√	√	√		√	√
Mississippi						
Missouri					√	√
Montana					√	√
Nebraska						
Nevada					√	√
New Hampshire		√		√	√	√
New Jersey	√		√			
New Mexico	√	√			√	
New York	√		√		√	√
North Carolina	√	√			√	√
North Dakota					√	
Ohio	√	√	√	√	√	
Oklahoma	√					
Oregon	√		√			
Pennsylvania	√	√	√	√		
Rhode Island	√	√			√	
South Carolina					√	√
South Dakota					√	√
Tennessee					√	√
Texas	√	√	√	√		
Utah					√	√
Vermont		√	√	√	√	√
Virginia	√	√			√	√
Washington				√	√	√
West Virginia					√	√
Wisconsin	√					
Wyoming					√	√
TOTALS	30	22	18	10	38	32

Federal Demand Response and Smart Metering Activities

The United States Congress

Federal legislation was enacted in both 2005 and 2007 that contained major provisions on demand response, smart meters, and smart grid. In 2008, numerous bills were introduced in both the House and the Senate dealing with energy and some were passed by one body or the other. As of the date of this report, one significant piece of energy legislation was signed into law by President Bush in 2008—an energy tax package that was included in the Emergency Economic Stabilization Act.

Energy Policy Act of 2005 (EPACT)

With the Energy Policy Act of 2005 (EPACT), signed into law in July 2005, Congress took its first steps ever to prescribe policy directly related to demand response.

Section 1252 of EPACT (Smart Metering) included the following:

- A requirement that the Department of Energy (DOE) conduct a national assessment of demand response potential and submit a report on such to Congress. This BFlansburg@ naruc.org report was issued in January 2006.
- A requirement that Federal Energy Regulatory Commission (FERC) undertake an Annual Assessment of Demand Response and issue a report on such. The statute directed FERC to base the assessment on a national survey of the electricity industry to determine, among other things, the penetration rate of advanced (smart) metering and other technologies that enable demand response. The first of these annual reports was issued by FERC in August 2006 (see below for more on FERC Annual Report).
- A statement that pursuit of demand response is in the policy interest of the United States. That provision is as follows:

  > "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."

- A new Standard under the Public Utilities Regulatory Policies Act (PURPA) focused on demand response and its enabling technologies. The new Standard calls for all utilities to offer and provide customers with time-based rates, and for the utility to provide a suitable meter to any customer requesting such rate, or demonstrate why compliance cannot be achieved. Based on the legislative construct of PURPA, however, utilities are not directly required to meet this Standard by EPACT. Instead, the language requires that state public utility commissions and other bodies with jurisdiction over public/municipal and rural electric cooperative utilities conduct an investigation and make a finding as to whether this new Standard is appropriate to be put in place in a particular jurisdiction or at a particular utility. Jurisdictional bodies were given one year to initiate consideration of the Standard, and were expected to complete such within two years.

Section 103 (Energy Use, Measurement and Accountability) included the following:

A requirement that by October 1, 2012 that all federal buildings "for the purposes of efficient use of energy and reduction in the cost of electricity used in such buildings, be metered. Each agency shall use, to the maximum extent practicable, advanced meters or advanced metering devices that provide data at least daily and that measure at least hourly consumption of electricity in the federal buildings of the agency. Such data shall be incorporated into existing federal energy tracking systems and made available to federal facility managers."

The legislation required the U.S. Department of Energy to, within 180 days of enactment, develop plans and guidelines for the implementation of this requirement as part of its Federal Energy Management Program (FEMP) and for each federal agency, within 180 days of such plan being available, to develop its own implementation plan.

Energy Independence and Security Act of 2007 (EISA)

The Energy Independence and Security Act (EISA) was signed into law on December 19, 2007. It included an entire Title devoted to Smart Grid and Demand Response. Several demand response provisions were also included in other parts of EISA. They include:

Section 571 National Action Plan for Demand Response:

This Section states that FERC shall do two things: conduct a National Demand Response Potential Assessment and develop a National Action Plan for Demand Response.

Within 18 months of enactment (i.e., June 18, 2009) FERC shall submit a report to Congress that estimates nationwide demand response potential in 5- and 10-year horizons, including state-by-state data. A methodology for updating the estimates on an annual basis is also to be included. The report is to include an estimate of how much of this potential can be achieved by specific policy recommendations. The report is also to address a specific aspect of barriers to demand response, i.e. "barriers to demand response programs offering flexible, non-discriminatory, and fairly compensatory terms for the services and benefits made available."

Within one year after the completion of the report (i.e., June 18, 2010) FERC shall develop a National Action Plan that meets objectives which include: identification of technical assistance needed by states, identification of requirements for a national communications program in support of demand response, and development/ identification of analytical tools, model contracts, and other "support materials" for use by customers, utilities, and demand response providers.

Within six months of the Plan being published, FERC, together with DOE, shall submit a proposal to Congress to implement the Plan, including "any agreements secured for participation from States or other participants."

Section 1301 Statement of Policy on Modernization of Electricity Grid

This Section consists entirely of a statement of overall support for modernization of the transmission and distribution system of the nation. Its significance may be that it provides a long list (10 items) of modernization items, which it says "together characterize a Smart Grid."

Section 1302 Smart Grid System Report

This Section requires the DOE Office of Electricity Delivery and Energy Reliability to, no later than one year after enactment (i.e., on December 18, 2008) and every two years thereafter, issue a report to Congress "concerning the status" of smart grid "deployments" and any regulatory or government barriers to "continued deployment." The report shall include "current status and prospects" for smart grid development, including information on technology penetration, communications network capabilities, costs and obstacles. The report may include recommendations for state and federal policies or actions.

Section 1303 Smart Grid Advisory Committee and Smart Grid Task Force

Within 90 days of Enactment (i.e., March 18, 2008), the Secretary of Energy shall establish a Smart Grid Advisory Committee. This is to be a formal Advisory Committee subject to formal federal procedures for such entities. The Committee shall include eight or more members appointed by the Secretary who have "sufficient experience and expertise" to represent the full range of smart grid technologies and services and to represent both private and non-federal public sector stakeholders. The mission of the Advisory Committee will be to advise the secretary and other federal officials on various aspects of smart grid development, with specific mention being made of standards and protocols for interoperability and communication, and the use of federal incentive authority to encourage progress.

Also within 90 Days of Enactment (i.e., March 18, 2008), this Section requires that the DOE Office of Electricity Delivery and Energy Reliability establish a Smart Grid Task Force comprised of designated employees within DOE as well as elsewhere in the federal government (such as FERC and The National Institute of Standards and Technology, NIST). The Assistant Secretary of that DOE Office will serve as Director of the Task Force. The Act states that the mission of the Task Force is ensuring "awareness, coordination and integration" of activities within the federal government to support smart grid development. The Task Force shall meet at the call of the Director (i.e., DOE) as necessary.

Section 1304 Smart Grid Technology Research, Development, and Demonstration

This Section includes two separate (although not unrelated) directives to DOE on Research Development and Demonstration (RD&D). The first is to carry out a program focused on "Power Grid Digital Information Technology." Nine areas for DOE to purse are listed (on page 295) in the Act.

The second is to implement a "Smart Grid Regional Demonstration Initiative." As the title implies, the focus here is to have demonstration projects specifically focused on "advanced technologies for use in power grid sensing, communications, analysis and power flow control." DOE is also directed to leverage existing smart grid deployments. Five goals are listed (on page 295 of the Act) for projects funded under this Initiative.

Under the Demonstration Initiative, DOE is directed to carry out projects in up to five "electricity control areas" including rural areas and at least one area in which a majority of generation and transmission (G&T) assets are controlled by a tax-exempt entity. Any projects carried out shall be done in cooperation with the electric utility that owns the grid facilities in the control area. Such utility shall be provided with up to 50% of the cost of investments made by the utility as part of the project.

Section 1305 Smart Grid Interoperability Framework

This Section initiates a new effort by the federal government to ensure that protocols and standards necessary for "information management to achieve interoperability of smart grid devices and systems" are developed. The National Institute of Standards and Technology (NIST), an arm of the Commerce Department, is charged with coordinating the development of a "framework" that will accomplish this. NIST is to begin this new effort within 60 days of enactment (i.e., February 17, 2008) and within one year (i.e., December 18, 2008, not one year after February 17, 2008) shall publish an initial report on progress toward recommended or consensus standards and protocols.

The framework must be "flexible, uniform and technology neutral, including but not limited to technologies for managing smart grid information." It must be flexible to incorporate "regional and organizational differences" and "technological innovations."

The framework must consider the use of "voluntary uniform standards for certain classes of mass-produced electric appliances and equipment for homes and businesses that enable customers… and are manufactured with the ability to respond to electric grid emergencies and demand response signals by curtailing all, or a portion of, the electrical power consumed." Such voluntary standards "should incorporate appropriate manufacturer lead time."

In addition to the requirement to publish a report within one year, NIST shall issue "further reports at such times as developments warrant in the judgment of NIST." NIST is to issue a final report when it determines that the work is completed or that a federal role "is no longer necessary."

The Section contains a specific provision directed at FERC: "At any time after the Institute's work has led to sufficient consensus in the Commission's judgment, the Commission shall institute a rulemaking proceeding to adopt such standards and protocols as may be necessary to insure smart grid functionality and interoperability in interstate transmission….and regional and wholesale electricity markets."

The Section authorizes $5 million per year for Fiscal Year (FY) FY08 through FY12 for the activities required by the Section. This authorization is to NIST and therefore will be subject to the Department of Commerce (DOC) budget appropriations, and not that of DOE.

Section 1306 Federal Matching Funds for Smart Grid Investment Costs

This Section creates a major new federal grant program at DOE, where the grants will provide "reimbursement" of 20% of qualifying smart grid investments made on or after the date of enactment (December 19, 2007).

The Section lists eight areas (on page 298) for qualifying investments that appear to cover the spectrum of demand response, advanced metering, and smart grid. It also gives DOE the authority to identify other areas. DOE is also directed to, in making such grants, "reward innovation and early adaptation, rather than deployment of proven and commercially viable technologies." The Act also lists nine investment areas (on page 299) that do not qualify for grants.

The descriptive language of many of the qualifying areas for investment includes a reference to "Smart Grid functions." This term is later in the Section defined to mean any of eight specific functions, with DOE also being given authority to prescribe additional functions.

DOE shall within one year of enactment (i.e., December 18, 2008), publish the procedures for how the grant program will be administered and implemented. No specific sums are authorized for the program, and instead the provision authorizes "such sums as necessary" for administration and the grants themselves. (Note: Earlier versions of the Energy Bill included substantial authorizations for this program, on the order of $500 million per fiscal year.)

Section 1307 State Consideration of Smart Grid

This Section amends PURPA to create two additional PURPA Standards. (Note: Two new PURPA Standards are also created in Section 532.) These standards are in the form of requirements on parties such as utilities to undertake certain actions. The standards are not directly prescriptive on these parties, however; it is up to state utility regulatory commissions, or the bodies that govern other types of utilities, to decide that the standards should be actually adopted by utilities subject to their jurisdiction. The only direct mandate with PURPA standards is for the state or other jurisdictional body to consider whether the new Standard should be implemented and to demonstrate that it has undertaken such consideration.

The first new Standard would require utilities—prior to undertaking investments in non-advanced grid technologies— to demonstrate that they have considered investments in "qualified smart grid systems" based on a list of factors (on page 301) in the section that include total costs, cost-effectiveness, etc. This Standard would also allow utilities to recover from ratepayers any capital, operating expenditures, or other costs of the smart grid investment, including a reasonable rate-of-return. Furthermore, this Standard would allow utilities to recover remaining book value of any equipment rendered obsolete by the deployment of such smart grid systems. There is no description or list relative to what "qualified smart grid systems" would be.

The second new Standard would require that all "electricity providers" provide "electricity purchasers" with "direct-access," in written or electronic machine-readable form as appropriate, information on time-based wholesale and retail prices, usage, intervals and projections related to both prices and usage, and sources of power "to the extent that it can be determined" by type of generation and associated greenhouse gas emissions. Purchasers "shall be able to access their own information at any time through the internet and on other means of communication elected by that utility for Smart Grid applications." Other "interested persons" shall be able to access information "not specific to any purchaser" through the Internet.

States and other jurisdictional bodies shall within one year of enactment (i.e., December 18, 2008) commence the consideration of these standards or set a hearing date for consideration. Such consideration shall be completed, and a determination of standard adoption made within two years of enactment (i.e., December 18, 2009).

Section 1309 DOE Study of Security Attributes of Smart Grid System

Within 18 months of enactment (i.e., June 18, 2009), DOE shall issue a report to Congress on the results of a study that provides a "quantitative assessment and determination of the existing and potential impacts" of the deployment of Smart Grid systems on improving the security of the nation's electricity "infrastructure and operating capability." The Report shall include recommendations in four areas, including prevention, communications, and restoration related to interruptions.

Emergency Economic Stabilization Act of 2008

An Energy Tax Package was under development in Congress for several years prior to 2008. In September 2008, the package was finally enacted into law via its inclusion in the Emergency Economic Stabilization Act of 2008.

Included in this tax package is a provision to accelerate the depreciation period for smart meters and smart grid technologies. The tax code previously required a 20-year depreciation period for these items, in recognition of the long asset life they represented. The new law makes a permanent change in this depreciation rate to 10 years, in recognition that these items should be more aligned with the rates granted to high technology items that evolve at a more rapid pace.

The new tax law includes the following language to describe smart meters that qualify for the new depreciation rate:

> "The term 'smart electric meter' means any time-based meter and related communication equipment which is capable of being used by the taxpayer as part of a system that—
>
> (i) measures and records electricity usage data on a time-differentiated basis in at least 24 separate time segments per day,
>
> (ii) provides for the exchange of information between supplier or provider and the customer's electric meter in support of time-based rates or other forms of demand response,
>
> (iii) provides data to such supplier or provider so that the supplier or provider can provide energy usage information to customers electronically, and
>
> (iv) provides net metering."

The new law includes the following language to describe smart grid technologies that qualify for the new depreciation rate:

> "The term 'smart grid property' means electronics and related equipment that is capable of—
>
> (i) sensing, collecting, and monitoring data of or from all portions of a utility's electric distribution grid,

(ii) providing real-time, two-way communications to monitor or manage such grid, and

(iii) providing real time analysis of and event prediction based upon collected data that can be used to improve electric distribution system reliability, quality, and performance."

The new depreciation rates apply to property places in service after the date of enactment (September 26, 2008).

Federal Energy Regulatory Commission (FERC)

The Federal Energy Regulatory Commission (FERC) has taken numerous steps relative to demand response. It has held several technical conferences to hear from experts and stakeholders on the barriers to greater deployment of demand response and what policies FERC might pursue to overcome those barriers.

Compliance with Congressional Legislation

In September 2007, FERC released its "Assessment of Demand Response and Advanced Metering 2007" in accordance with EPACT 2005. (EPACT 2005 requires that FERC annually create a report of demand response and smart metering activities—the 2007 report is FERC's second. Whereas the 2006 report was based on a nationwide survey to collect and assess baseline information that could be used for policymaking, the 2007 report simply identified developments in demand response and advanced metering since the time the 2006 assessment was issued.) In the report, FERC asserts that both deployment of and interest in demand response had "increased significantly" since 2006. Specifically, the report points to a number of deployment successes and identifies several trends; the latter includes:

- Increased participation in demand-response programs
- Increased ability of demand resources to participate in Regional Transmission Organization/ Independent System Operator (RTO/ISO) markets
- More attention to the development of a smart grid that can facilitate demand response
- More interest in multi-state and state-federal demand response working groups
- More reliance on demand response in strategic plans and state plans
- Increased activity by third parties to aggregate retail demand response

Regarding smart metering, the assessment highlights the fact that many large utilities are planning to deploy smart meters and that a number of states have taken action. Some states have approved smart meter projects and/or deployments. Other states have established or re-established smart metering working groups and/or have opened smart metering proceedings. If all the deployments announced actually occur, there will be, according to FERC, more than 40 million smart meters deployed within the next few years.

FERC will published another aaassessment in September 2008[RHS1], but thereafter will only publish the comprehensive survey-based review during even-numbered years. In odd-numbered years it will release "informational update reports."

FERC Proceedings

FERC has issued a number of rulings in recent years in cases involving demand response at individual RTOs/ISOs under its jurisdiction. One notable focus area of these orders has been to expand the use of demand response in additional types of regional markets, in particular ancillary services.

In February 2008, FERC issued a Notice of Proposed Rulemaking (NOPR) on Wholesale Competition in Regions with Organized Electric Markets. A major focus of the NOPR was the role of demand response at the wholesale level in organized markets—specifically, the greater use of market prices to elicit demand response during periods of operating-reserve shortages.

In the NOPR, FERC put forth five proposals regarding Organized Markets and demand response:

1. Purchase demand response resources in their markets for certain ancillary services, similar to any other resources.
2. Eliminate, during a system emergency, a charge to a buyer in the energy market for voluntarily taking less electric energy in the real-time market than purchased in the day-ahead market.
3. Permit an aggregator of retail customers (ARC) to bid demand response on behalf of retail customers directly into the organized energy market.
4. Modify their market rules, as necessary, to allow the market-clearing price, during periods of operating reserve shortage, to reach a level that rebalances supply and demand so as to maintain reliability while providing sufficient provisions for mitigating market power.
5. Study whether further reforms are necessary to eliminate barriers to demand response in organized markets.

Over the course of 2008, FERC received comments on the NOPR and held technical conferences to receive further comment from demand response experts and stakeholders.

In October, 2008 FERC issued its decision in this rulemaking procedure. The Final Rule establishes regulations that are to "strengthen the operation and improve the competitiveness of organized wholesale electric markets through the use of demand response." Specifically, the Final Rule directs each ISO/RTO to do the following:

- Accept bids in its markets for ancillary services from technically capable demand response resources as it does for other resources.
- Eliminate certain charges to buyers in the energy market for voluntarily reducing demand during a system emergency.
- Permit an aggregator of retail demand responses to bid the combined demand responses directly into an RTO's or ISO's organized markets unless this is not permitted by the laws or regulations of the relevant electric retail regulatory authority.
- Allow the market price to more accurately reflect the value of energy during a period of operating reserve shortage, while providing for market power mitigation.
- Assess and report on any remaining barriers to comparable treatment of demand response resources in its organized markets.

Furthermore, the Final Rules set regulations designed to encourage long-term power contracts; to strengthen the role of market monitors; and to enhance ISO/RTO responsiveness to customers and other stakeholders.

Finally, each ISO/RTO is to file a compliance report with FERC within six months of the date the Final Rule is published in the Federal Register. The report is to explain how existing or planned practices comply with the Final Rule.

Department of Energy (DOE)

The U.S. Department of Energy (DOE issued a report in 2006 on Demand Response Potential pursuant to Congressional direction in EPACT 2005.

DOE has in recent years initiated and supported to numerous state and regional efforts focused on demand response. The Mid-Atlantic Distributed Resource Initiative (MADRI), the Midwest Distributed Resource Initiative (MWDRI) and the Pacific Northwest Distributed Resources Project (PNDRP) all are ongoing collaborative efforts involving state policy makers, electric utilities, RTOs/ISOs, demand response companies, and various stakeholders. These collaborative efforts have worked to develop information, some of it policy-based, which can be used by States to advance the use of demand response.

DOE has supported numerous educational and research efforts on demand response in individual states. DOE has also funded a variety of national level research efforts, many undertaken by Lawrence Berkeley National Laboratories, aimed at developing new information and understanding of demand response.

DOE has funded and spearheaded considerable activity on demand response through its Smart Grid efforts. Research, development, and demonstration have been funded, including efforts focused on smart appliances and use of demand response in tactical, geographically specific areas.

As noted in the section above on the Energy Independence and Security Act (EISA), DOE has numerous responsibilities to carry out under that Act and efforts to do so by the Agency are presently underway.

Also, as noted in the Congressional Section above, DOE, through its Federal Energy Management Program (FEMP) continues to work to implement the Federal Building Metering Requirement enacted under EPACT 2005.

State Demand Response and Smart Metering Regulatory and Legislative Activities

Alabama

Regulatory:

- In June 2007, the Alabama Public Service Commission decided not to adopt PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005. Its decision, which followed its Staff's May 2007 recommendations, states that EPACT 1252 is unnecessary as Alabama Power Company (1) already offers TOU rates to "all available customer classes, as required by the standard in Section 1252"; (2) provides "appropriate meters, as also required" by EPACT 1252; and (3) is deploying smart meters.

Alaska

Regulatory:

- In August 2007, the Regulatory Commission of Alaska decided not to adopt PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005. In its Order declining adoption, the Commission indicated that it found insufficient evidence that it would be appropriate "to impose smart metering requirements on all customer classes." Specifically, it noted, "Given the slight variation in the incremental cost of energy, we do not find that the evidence in the record of this proceeding supports a conclusion that smart metering would result in significant conservation of energy, efficiency of electric utilities, and equitable rates for consumers." Finally, it reserved the right to investigate the PURPA standard in the future as circumstances warrant. The proceeding, however, remains open due to Commission consideration of other provisions of EPACT 2005.

Arizona

Regulatory:

- In July 2007, the Arizona Corporation Commission adopted a modified version of PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005. The version the Commission adopted applies the PURPA standard to all electric distribution companies within its purview instead of only to companies with retail sales of more than 500,000 MWh (the latter relates to original language in the EPACT statute). The Commission's version of EPACT 1252 reads:

  > "Within 18 months of Commission adoption of this standard, each electric distribution utility shall offer to appropriate customer 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. Within 18 months of Commission adoption of this standard, each electric distribution utility shall investigate the feasibility and cost-effectiveness of implementing advanced metering infrastructure for its service territory and shall begin implementing the technology if feasible and cost-effective."

Arkansas

Regulatory:

- In January 2007, the Arkansas Public Service Commission issued an Order establishing "Guidelines on Resource Planning for Electric Utilities," which require utilities to consider all generation, transmission, and demand response options in the region. Specifically, these guidelines direct utilities to "give 'comparable consideration' to demand and supply resources and to assess 'all reasonably useful and economic supply and demand resources that may be available to a utility or its customers,' and to identify and investigate resources including 'energy efficiency, conservation, demand-side management, interruptible load, and price responsive demand.'"
- In August 2007, the Commission decided not to adopt PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005. The Commission declined adoption because it indicated that it can best foster the "the development of various Demand Response technologies and practices" through "utility-specific rate or tariff proceedings." In the course of the proceeding to consider EPACT 1252, utilities filed and the Commission approved "quick start and/or pilot" efficiency programs to run through 2009, some of which include demand response. By way of further evidence of giving due consideration to EPACT 1252, the Commission noted that it issued "Guidelines on Resource Planning for Electric Utilities" in a related proceeding through which it addresses demand response and metering. Specifically, these guidelines direct utilities to "give 'comparable consideration' to demand and supply resources and to assess 'all reasonably useful and economic supply and demand resources that may be available to a utility or its customers,' and to identify and investigate resources including 'energy efficiency, conservation, demand-side management, interruptible load, and price responsive demand.'"

California

Regulatory:

In California there are many proceedings addressing demand response, smart metering, smart grid, and time-of-use rates. To better describe the various activities in the state, the California section of the report is organized around different issues and topic areas instead of around individual proceedings.

- **Investor Owned Utilities (IOUs) and Demand Response Issues**

  In January 2007, the California Public Utilities Commission (CPUC) initiated a proceeding to address several demand response related issues of the regulated, investor-owned utilities in California—namely, Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), and Pacific Gas and Electric (PG&E). These issues are:

  - Protocols for load impact estimates
  - Cost-effectiveness methodologies
  - Megawatt goals
  - Alignment with California Independent System Operator market design protocols

  A Scoping Memo in this proceeding, issued in April 2007, divided the work into two phases. Phase 1, which began in spring 2007, "focuses on the development of protocols and methodologies related to existing and possible future DR activities." Phase 2, which was formally launched in October 2007, "focuses on the more policy-oriented issue of DR goals."

- **Load Impact**

  In April 2008, the CPUC issued an Order in which it adopted "Demand Response Load Impact Estimation Protocols" for SCE, SDG&E, and PG&E and directed the utilities to:

- File initial evaluation plans on all demand response activities for the year 2008.
- Follow adopted protocols in preparing load impact estimates to be filed in their 2009-2011 Demand Response Applications.
- Perform annual studies of their demand response activities using the adopted protocols, and file reports annually on April 1.
- Use the adopted protocols to estimate demand response load impacts for long-term procurement planning and resource adequacy purposes, "unless otherwise directed by the ALJ or Assigned Commissioner in [a] relevant Commission proceeding."

The Order completes the load impact estimation in Phase I of a proceeding, which was to focus on measurement and evaluation protocols and "methodologies related to existing and possible future DR activities." Phase II of the proceeding, outlined in April 2007 and begun in October 2007, will set goals for demand response and remains open.

- **Cost Effectiveness**

  The CPUC is currently addressing specific issues related to developing cost-effectiveness methodologies for demand response programs. This includes exploring "(1) avoided cost calculations and assumptions; and (2) the estimated value of differential notification time and program triggers." Several workshops have been or will be conducted.

- **Integration with CAISO**

  The CPUC is formally considering of how demand response can support the CAISO's efforts to incorporate demand response into wholesale market design protocols. The CPUC has "noted the need to ensure that DR programs adapt to function within the day-ahead market that will be implemented with the CAISO Market Redesign and Technology Upgrade (MRTU). The CAISO plans to implement MRTU before the summer of 2009. The Commission has recommended that the CAISO account for existing DR in a way that does not promote procurement of redundant supply-side resources. A key to resolving this issue is identifying where there are disconnects or gaps between existing retail DR programs and the CAISO's operational needs for the wholesale market, both at this time and when MRTU will be implemented."

- **Integration with Energy Efficiency**

  In October 2007, the CPUC issued a Decision in a large, ongoing energy efficiency proceeding in which it required the state's IOUs (PG&E, SCE, SDG&E and Southern California Gas) to do the following:

  - "Engage in long-term strategic planning" and produce a "single, statewide IOU strategic plan for energy efficiency through 2020 and beyond." This Strategic Plan should "integrate customer demand-side programs, such as energy efficiency, self-generation, advanced metering, and demand response, in a coherent and efficient manner."
  - File individual 2009–2011 energy efficiency portfolio applications, ensuring that they "provide sufficient strategies and funding to address opportunities to reduce critical peak loads and improve system load factors."

  As a result, in June 2008 the IOUs collectively filed their "California Energy Efficiency Strategic Plan." The CPUC, however, decided not to approve, reject, or modify the IOUs' plan. Instead, in July 2008 it initiated a new proceeding through which it subsumed "the efforts made by all of the participants" in developing the "California Energy Efficiency Strategic Plan" into a "Commission-approved Plan." The creation of a new strategic plan, the CPUC asserted, "allows for development of a record and consideration of ideas above and beyond the detailed strategies and implementation plans discussed in the joint Utilities' CEESP application."

In September 2008, the CPUC issued a Decision adopting a new plan created from the IOUs' plan. The CPUC's plan—the "California Long-Term Energy Efficiency Strategic Plan"—not only calls for demand response, but dedicates an entire chapter about the deployment of demand response and smart metering in conjunction with efficiency, conservation, and distributed generation. The CPUC's plan is similar to but different from the IOUs' plan—notably, the CPUC added to its plan a vision statement about DSM coordination and integration.

The CPUC's September 2008 Decision also included several directives about how to realize the "California Long-Term Energy Efficiency Strategic Plan:"

- The state's IOUs are to file amendments to their 2009–2011 energy efficiency program applications so as to incorporate the strategies of the new plan.
- The IOUs are to assist the CPUC with developing "a statewide energy efficiency brand and an integrated marketing education and outreach (ME&O) strategy."
- The "California Long-Term Energy Efficiency Strategic Plan" is to be updated in 2010, in time for the IOUs to reference it while planning for their 2012–2015 efficiency-program applications.

The CPUC also took action in another proceeding to integrate demand response and energy efficiency. Via an April 2008 ruling, it directed the IOUs to "include integrated demand-side management (IDSM) programs in their 2009–2011 energy efficiency (EE) and demand response (DR) portfolio applications." (The demand response portfolio applications were filed in June 2008; the efficiency applications were filed in July 2008.) Furthermore, the CPUC stated that programs "involving the coordination and/or integration of EE and DR measures, funding, or programs" should be included in both the efficiency and demand response applications.

- **Demand Response 2009 – 11 Program Applications**

In June 2008, the IOUs filed applications with the CPUC for their 2009-2011 demand response programs and budgets.

SCE's application as submitted proposes a budget of approximately $209 million, consisting of $189.6 million for the 2009-2011 demand response program portfolio and $19.8 million for four proposed "DR-forward" contracts with third-party providers (if approved). SCE is proposing a variety of program activities for 2009-2011 which include both continuations and modifications of their existing demand response programs, activities, and tariffs, including a capacity/demand bidding program as well as critical peak pricing and real-time pricing for certain customer classes. Additionally, they are proposing related efforts regarding public education and marketing, and deployment of new demand-response-enabling technologies.

SDG&E's application proposes a $48.5 million demand response budget for the three-year period. SDG&E outlines the principles it used to develop the application: a simplification of its demand response offerings, organized by customer market segments; a comprehensive demand response portfolio for "all customers" to participate in demand response programs and rates; and promoting automated controls to enhance demand response participation and value.

PG&E proposes a $147.2 million demand response budget for the three-year period. PG&E proposes: to continue most of its 2008 demand response programs; that its PeakChoice program (which allows customers to elect their program options) serve as their principal demand response program for directly-enrolled customers; and increased use of third-party demand response aggregators. Additionally, PG&E will have various pilots activities including those that promote automated demand response and that enhance PG&E's use of renewable energy, by utilizing thermal energy storage as well as plug-in electric vehicles "to help with increased ramp-up, ramp-down and load following needs of CAISO [California Independent System Operator] due to the intermittence of renewable resources."

All three IOUs' proposals call for greater integration of their demand response programs with their energy efficiency efforts; integrating demand response programs with the CAISO's Market Redesign and Technology Upgrade (MRTU); and greater use of AMI for demand response purposes as advanced meters are deployed.

In August, 2008, the Commission determined that the applications from the utilities did not meet the requirements originally set forth and that the applications must be amended and refilled. Among the areas the Commission requested further work on was the development of impact estimates using the recently adopted protocols.

- **IOUs and AMI Deployment**

  The Commission in recent years initiated and completed a generic proceeding to establish advanced metering policy. The California IOUs are now pursuing very large AMI deployments under the direction of the CPUC and separate proceedings have been or are being conducted in the case of each company. SDG&E's deployment has been approved by the Commission and SCE has received a proposed ruling approving their application. PG&E received approval from the Commission and now has filed an updated application to modify certain functionality aspects of its deployment.

- **Time-of-Use Pricing**

  In July 2008, the CPUC issued a Decision in which it approved, among other things, a plan for Pacific Gas & Electric to implement dynamic pricing as the default rate option for mid- to large-size customers. According to the plan, the utility's introduction of dynamic pricing—specifically, critical-peak pricing (CPP) and real-time pricing (RTP)—and TOU rates will be incremental and will complement its AMI deployment plan. PG&E plans to introduce new rates according to the following schedule:

  - By May 2010:
    - CPP rates for C&I customers with load greater than or equal to 200 kW
    - Optional CPP rates, that include TOU rates during non-CPP periods, for medium C&I, small commercial and residential customers
  - By February 2011:
    - Default CPP rates for C&I customers with load less than 200 kW that have had a smart meter for more than one year
    - Default CPP rates for agricultural customers with maximum load greater than 200 kW that have had a smart meter for more than one year
    - Default TOU rates for agricultural customers with maximum load less than 200 kW that have had a smart meter for more than one year
    - Optional CPP rates for agricultural customers with maximum load less than 200 kW
  - By May 2011:
    - Optional RTP rates for all customer classes

  While the July 2008 Decision does not directly affect California's other IOUs the CPUC Ruling does make clear that the Decision could apply to the utilities in future rate-design proceedings. It recommends, furthermore, "that SCE and SDG&E take this decision into consideration."

- **Long Term Procurement Plans**

  In February 2008, the CPUC opened a proceeding to consider the "policies, practices and procedures" of establishing long-term procurement plans, including considering demand response. The CPUC notes, "A primary focus in this [long-term procurement plan] proceeding is implementation of the [Energy Action Plan] loading order, in the order of EE, demand response (DR), renewables, distributed generation, and clean fossil-fuel." So far in the proceeding, there have been a number of workshops.

- **California Solar Initiative**

  In December 2006, the CPUC ordered that—pursuant to statute creating the California Solar Initiative (CSI)—recipients of CSI incentives must take service on applicable existing TOU rates.

  However, as the CPUC reports: "An unintended consequence was that a few customers with high peak demand had higher electricity bills after reducing demand with solar than on 'flat' electricity rates without solar. In June 2007, the legislature, the governor and the CPUC all took necessary action to delay the TOU mandatory requirement until new TOU rates are established as part of each utility's rate case." Related legislation (AB 2768) is pending in the Legislature.

- **Title 24 Building Codes**

  In April 2008, the California Energy Commission adopted its "2008 Building Efficiency Standards." The standards, also known as Title 24, regulate construction of most residential and nonresidential buildings. The CEC's new standards reflect updates aimed at not only increasing energy efficiency but also reducing peak-demand energy use; they write:

  > "Many of the changes in the standards are tailored to help reduce not only overall energy use, but peak energy use—electricity demand on hot summer days when air conditioning loads can cause California's need for power to nearly double. The latest efficiency standards will cut California's peak energy demand by 129 megawatts the first year the standards are in effect and increase cumulatively in subsequent years."

  The new standards build upon and enhance the CEC's precedent-setting 2005 Title 24 standards that introduced a Time-Dependent Valuation (TDV) of kWh saved by energy efficiency measures, whereby all kWh saved are not valued equally and where the amount of savings that are expected to reduce peak power consumption is factored in.

- **Updated Energy Action Plan**

  In February 2008, the CEC and the CPUC jointly issued their "2008 Update: Energy Action Plan." In the section on demand response, the CEC and CPUC note two accomplishments and list six action items:

  Accomplishments:

  - Advanced metering installation in progress
  - Investor-owned utility continuous improvement in demand response program offerings

  Next Steps:

  - Adopt load-management standards to establish a demand-response infrastructure
  - Provide legislative authorization for time-varying pricing for residential consumers
  - Make more progress on dynamic pricing rate design reform for all types of consumers
  - Ensure programs that utilize advanced metering, tariff, and other automated demand response infrastructure
  - Modify retail programs so that they can more fully participate in the California ISO's new wholesale market structure
  - Develop a load impact and cost-effectiveness protocol for demand response programs

Furthermore, the report ties the success of meeting state-set emissions standards to deploying demand response. It also says that California is “nowhere near” the goal of 5% peak-demand reduction set in the first “Energy Action Plan” and that, as a result, the state must “reinvigorate” its demand response efforts.

The “2008 Update: Energy Action Plan” is not a new plan but a follow-up to California’s 2003 “Energy Action Plan” and 2005 “Energy Action Plan II” which, among other actions, made it California policy that energy efficiency and demand response would be first in the state’s “loading order” in acquiring new power resources. The 2008 Update is a review of the state’s activities relative to these two plans and the California Global Warming Solutions Act of 2006. Furthermore, the CEC and CPUC stress that the “2008 Update: Energy Action Plan” does “not supersede or replace” the “2007 Integrated Energy Policy Report.”

- **Integrated Energy Policy Report**

  In December 2007, the CEC issued the “2007 Integrated Energy Policy Report (IEPR).” In it, the Commission recommends that California:

  - “Integrate distribution planning with other resource procurement processes to support the use of new low-carbon resources and applications—renewables, demand response, efficient combined heat and power, distributed generation, energy storage, advanced metering infrastructure, and plug-in hybrid electric vehicles.”
  - “Allow utilities to recover the remaining book-value costs of equipment rendered obsolete by the deployment of a qualified smart grid system.”

- **Load Management and Demand Response Standards**

  In January 2008, the CEC opened an “informational and rulemaking proceeding” with the intent of adopting the load management and demand response standards recommended by the 2007 IEPR by addressing:

  - Functional capabilities of the advanced meters being installed and/or proposed by the utilities
  - Electric rate design
  - Development of information, education, and implementation strategies that will inform voluntary customer participation
  - Functional design, communication capabilities, and dispatch logistics of technologies that allow customers to automate their voluntary response to price and reliability signals
  - Opportunities for capturing the peak load reduction and conservation potential of energy storage and permanent load-shifting technologies

  Regarding AMI, the CEC has speculated that possible load management standards including AMI might be:

  - Adopting statewide standard protocols for AMI functionality
  - Requiring all utilities to develop business cases for AMI deployment consistent with statewide standard protocols for AMI functionality
  - Requiring all utilities to prepare a business case for deploying AMI
  - Requiring all utilities to deploy AMI

Legislative:

- In February 2008, the California State Legislature began considering smart grid legislation; SB 1438 would establish as California policy the imperative "to encourage, and where appropriate, mandate the utilization of smart grid systems…by electric utilities…including electrical corporations, electrical cooperatives, and local publicly owned electric utilities." If passed, the legislation would, among other actions:

  - Require the California Public Utilities Commission (CPUC), by July 1, 2010, and in consultation with the California Energy Commission (CEC) and the Independent System Operator (CAISO), to determine the requirements for a smart grid deployment plan "consistent with the policies set forth in the bill and federal law."
  - Require that the smart grid "improve overall efficiency, reliability, and cost-effectiveness of electrical system operations, planning, and maintenance."
  - Require each electric utility, by July 1, 2011, to develop and submit a smart grid deployment plan to the CPUC for approval and authorize the CPUC to allow a utility to recover "reasonable costs of deploying smart grid technologies and services."
  - Authorize a smart grid deployment plan that is adopted "to provide for deployment of smart grid products, technologies, and services by entities other than electrical corporations."
  - Authorize smart grid technologies and services to be deployed in an incremental manner to maximize the benefit to ratepayers and to achieve the benefits of smart grid technology, authorize the CPUC to modify or adjust the bill's requirements for any utility with fewer than 100,000 service connections as circumstances merit, and require the CPUC (in consultation with the CEC, CAISO, and electric utilities) during deployment to evaluate "the impact of deployment on major initiatives and policies."
  - Require a local publicly owned electric utility to develop by July 1, 2011, and adopt by July 1, 2012, a smart grid deployment plan consistent with the policies set forth in the bill and federal law.

  In May 2008, SB 1438 passed the Senate and was referred to the State Assembly where it was in Committee as of June 2008[RHS2].

- Since February 2008, the California State Senate has been considering SB 1491 which would provide guidance for how the CEC may or may not regulate deployment of programmable communicating thermostats. (This bill relates to a now-withdrawn plan by the CEC to include the mandatory deployment of programmable communicating thermostats in its 2008 building energy code.) In particular, the legislation would set the following standard:

  > "The [California Energy] commission shall not adopt or approve a building standard that requires installation of a device that may be controlled remotely by any person or entity other than a building resident the utility customer, including, but not limited to, a programmable communicating thermostat equipped with a non-removable radio data system communications device that is compatible with the default statewide demand reduction communications system used by utilities to send price and emergency signals, unless all of the following conditions apply to the device:
  >
  > (a) The device shall be installed without default settings.
  >
  > (b) Only the resident utility customer may authorize remote control of the device by another person or entity.

(c) The resident utility customer retains the right to deny access to or to override a remotely controlled setpoint at any time."

The Senate passed the bill in May 2008 and referred it to the State Assembly. The State Assembly modified the legislation and, in August 2008, passed its own version of it. The Senate concurred with the State Assembly's amendments and again passed the legislation, and the bill now awaits the Governor's signature or veto.

Colorado

Regulatory:

- In March 2008, the Colorado Public Utilities Commission decided not to adopt PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005. The Commission stated that its decision is based in part on the fact that the Public Service Company of Colorado is building (with Xcel Energy) the Smart Grid City in Boulder, CO, and that Aquila Networks intends to deploy AMI in the City of Pueblo. Furthermore, the Commission said that it intends to consider "issues related to Smart Metering, among other issues, in an upcoming investigatory docket." As a result, the Commission determined "that implementation of the Smart Metering standard is not appropriate at this time." Previously, in December 2006, the Commission had deferred consideration of EPACT 1252 until after reviewing the results from Public Service Company of Colorado's Residential Price Response pilot program.
- In August 2006, the Public Service Company of Colorado asked the Commission to open a proceeding to consider DSM issues, including possible improvements to the utility's DSM programs, including demand response. The Commission suspended the proceeding in April 2007 pending the outcome of state legislation that addresses demand response (HB 07-1037)—Governor Ritter signed this bill in May 2007, and the proceeding then resumed. In June 2007, most parties to the proceeding filed a Joint Motion to Close Docket. The Commission heard oral arguments later in June 2007 about the Joint Motion to Close Docket as well as about the question of whether the legislation Governor Ritter signed in May 2007 addressed all issues raised by EPACT 2005. In July 2007, the ALJ issued a Recommended Decision suggesting that the Joint Motion to Close Docket be accepted and that the proceeding be closed. It also recommends that the Public Service of Colorado file—when it files its next Least Cost Resource Plan—an application that "(a) addresses the Demand Side Management issues which are the subject of this docket; (b) expands its Demand Side Management programs beyond current levels, taking into account the provisions of House Bill No. 07-1037, as enacted; and (c) includes 'specific recommendations with respect to the majority of the [Demand Side Management] issues that are the subject of this investigation.'"

Legislative:

- In May 2007, Governor Ritter signed legislation that, among other things, mandates the Colorado Public Utilities Commission establish peak-demand reduction goals for investor-owned utilities (House Bill 07-1037). Specifically, the standard is a 5% reduction of "retail system peak demand" (MW) and 5% of "retail energy sales" (MWh), compared to 2006 levels, by 2018. Furthermore, the law directs the Commission to direct all utilities to develop demand response programs—requiring that the programs "give all classes of customers an opportunity to participate and shall give due consideration to the impact…on non-participants and on low-income customers." The Commission also is to direct utilities to file each year a report describing their DSM programs, their peak-demand savings, and how they measured those savings.

Connecticut

Regulatory:

- In February 2008, the Connecticut Energy Advisory Board, per direction in the Energy Efficiency Act of 2007 (Public Act 07-242), filed a report with the General Assembly about "the efficacy, innovativeness and customer focus of [the state's] electric conservation programs." The report discusses demand response.

- In December 2007, the Connecticut Department of Public Utility Control (DPUC) issued a Decision in which it set a new timeline for Connecticut Light & Power's deployment of 10,000 smart meters. CL&P had planned to start the deployment in January 2008. The DPUC determined, however, that the costs of CL&P's plan needed to be further understood—hence the delay, as described in its Final Decision:

  > "Therefore, while CL&P must move forward with the implementation of an advanced metering system, the Department will do so cautiously, reviewing customer response to the benefits that these meters are intended to provide."

  Accordingly, the DPUC's Final Decision directed CL&P to "study the technical capabilities" of its smart meters by conducting a "500 meter test" as well as a "10,000 meter study" with a concurrent time-based-rate pilot program. A report is to be submitted in December 2009 on the results of the pilot.

  CL&P's effort to deploy smart meters began in March 2007, when it filed an AMI plan with the DPUC. It filed a revised plan in July 2007 in response to a new state law (Public Act 07-242, Energy Efficiency Act of 2007), which mandated that every electric distribution company submit an AMI plan to the DPUC. (The deployment the DPUC just tabled was proposed in this filing.) To consider the plan, the DPUC reopened this docket, which it had closed in December 2006, after it directed CL&P to deploy time-based rates in accordance with Connecticut's Energy Independence Act of 2005.

- In July 2007, United Illuminating Company filed an AMI plan with the DPUC to remain in compliance with Connecticut's Energy Efficiency Act of 2007 (Public Act 07-242), signed in June 2007. In March 2008, the DPUC issued a Final Decision in its proceeding to consider UI's AMI plan. In the Final Decision, the DPUC approved UI's AMI plan, which includes the deployment of 5,000 smart meters. It also set this schedule for it:

  - "On or before November 15, 2008, UI shall submit final estimates for the costs of the MDM system necessary to move forward with Advanced Metering."
  - "On or before February 1, 2009, UI shall submit its plan to inform customers about the availability and benefits of Advanced Meter, as discussed herein."
  - "On or before December 1, 2008, UI shall file a report regarding how it tracks customers who are receiving more detailed bill information."

- In July 2007, the DPUC reopened a proceeding to address requirements of the Energy Efficiency Act of 2007 (Public Act 07-242). In May 2008, the DPUC issued a Draft Decision in which it says:

  - UI's current twoperiod TOU rate plan is sufficient to satisfy the requirements the Energy Efficiency Act of 2007.
  - By June 2008, UI shall submit a variable-peak-pricing tariff designed to be effective for all customers by January 2009.
  - By June 2008, UI shall submit TOU rates to become effective January 2009.

Legislative:

- In June 2007, Governor Rell signed the Energy Efficiency Act of 2007 (Public Act 07-242/House Bill 7432). It requires utilities to file AMI plans and TOU rates with the Commission.
- The General Assembly during 2008 is considering a bill—An Act Concerning Electric Rate Relief—that would support AMI and dynamic pricing (Senate Bill 1373).

Delaware

Regulatory:

- In January 2007, the Delaware Public Service Commission decided not to adopt PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005. The Commission agreed with the assessment of the proceeding's Hearing Examiner that based on the evidence presented the requirements of EPACT 1252 had already been met. In the Order, the Commission also decided that, relative to the state Electric Utility Retail Customer Supply Act of 2006, it will "take no action at this time regarding the feasibility of requiring advanced metering." The Commission will not require Delmarva Power & Light (DP&L) to implement a smart-metering pilot program because DP&L voluntarily submitted in February 2007 its "Blueprint for the Future," a "comprehensive proposal that will address issues such as the implementation in Delaware of advanced metering technology and time-based rates." This proceeding, however, is not closed, and the Commission reserves the right to enter future Orders as appropriate.
- In February 2007 Delmarva Power & Light filed with the Delaware Public Service Commission its proposed plan for smart metering, demand response, and energy efficiency. As outlined in the proposal—"Blueprint for the Future"—the utility intends to deploy smart meters to all of its residential customers in Delaware. It also plans to offer a direct-load-control program for AC units and heat pumps as well as financial incentives for commercial customers who reduce consumption during periods of peak demand. DP&L requested that the Commission establish a DSM working group as well as direct the working group formed in the Commission's EPACT 1252 proceeding to "review and report" on the smart metering proposal.

  In March 2008, the Commission held a public workshop. Afterward, the Commission solicited comments. In April 2008, the Commission's Staff filed its recommendations. The Staff supported DP&L's deployment of smart metering and demand response, provided that the AMI is compatible with PJM and MADRI and that the demand response enables participation in markets administered by PJM. It advised the Commission to review the "Blueprint for the Future" in DP&L's next rate case and to conclude this proceeding. In June 2008, the proceeding's Hearing Examiner made the following recommendations:

  - "The Commission should, at an appropriate time in the future, issue an Order approving the diffusion of the advanced metering technology into the electric distribution system network and that the demand response programs proposed in Delmarva's Blueprint for the Future be further explored for implementation. Delmarva should offer its proposal to permit it to establish a regulatory asset to cover recovery of costs associated with the deployment of Advanced Metering Infrastructure and demand response equipment in its next base rate case. The Commission, the Staff, and other parties remain free to challenge the level or any other aspects of the asset's recovery in rates when Delmarva seeks recovery of the regulatory asset in base rates. For ratemaking purposes, the Commission may wish to consider an appropriately valued regulatory asset for advanced metering infrastructure investment consistent with the matching principle giving consideration to both costs and savings in the context of its next base rate case proceeding."

- "The Commission should direct Delmarva, the Public Advocate, Staff, and any other interested parties to convene at a collaborative workshop to determine the viability of implementing any reasonable demand-side management or demand response programs in the near term."

In September 2008, the Commission issued an Order adopting the Hearing Examiner's June 2008 recommendations and closing the proceeding.

District of Columbia

Regulatory:

- In August 2007, the District of Columbia Public Service Commission issued an Order concluding that it would be inappropriate to adopt PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005 prior to completing two related proceedings: (1) One to consider Pepco's application to establish a comprehensive demand response, advanced metering, and energy efficiency plan, and (2) the other to investigate the procurement process for Standard Offer Service. The Commission will make a final decision about EPACT 1252 after resolving these other cases.
- In March 2007, the Commission created a Smart Metering Working Group as part of its EPACT 1252 proceeding to provide advice on considering the PURPA standards. The working group filed its report with the Commission in August 2007.
- The Commission opened a proceeding in April 2007 in response to Pepco's request to establish a "comprehensive demand response, advanced metering and energy efficiency plan" for its Washington, DC, customers. Pepco's proposed plan would establish a DSM cost-recovery mechanism and an AMI "adjustment mechanism" as well as a DSM collaborative and an AMI advisory group. The plan is called "Blueprint for the Future" and is part of the company's larger regional initiative that goes by the same name. Comments and reply comments have been filed. In October 2007, the Commission "transferred all issues and comments related to Pepco's proposal to administer DSM programs" to a different proceeding. Pepco appealed this decision in November 2007, but the Commission ruled in March 2008 that the decision stood. As a result, the efficiency and renewable programs in Pepco's "Blueprint for the Future" plan were transferred to a separate proceeding.
- In July 2006 the Commission opened a proceeding about improving Standard Offer Service and tasked its Standard Offer Service Working Group to provide advice. In October 2007, the Commission's Standard Offer Service Working Group filed its report. Later in October 2007 the Commission called for comments about the report as well as responses to several questions, including:
    - "Should Energy Efficiency (EE) and Demand Response (DR) be incorporated in to SOS procurements?"
    - "Would direct involvement by the SOS franchisee in the PJM RPM market allow the SOS franchisee to more easily obtain Demand Response and/or Energy Efficiency resources?"
    - "Should a dynamic pricing option for residential SOS be available as an alternative to the present flat rate residential SOS? If a dynamic pricing option is added to residential flat rate SOS, what form should such pricing take?
        a. Can dynamic pricing be accommodated under the present WFRSA? If so, how?
        b. Would a dynamic pricing option in residential SOS allow for greater customer control over electricity expenditures in comparison with a flat rate SOS?"

No subsequent activity in this proceeding was identified for this report.

- In July 2008, the Commission issued an Order in which it approved the revised smart-meter tariff proposed by Pepco and the District of Columbia Smart Meter Pilot Program, Inc., (SMPPI) for their smart meter pilot program, PowerCentsDC. (In the Order the Commission also noted that it will issue a Notice of Final Rulemaking.) Days later, Pepco announced that it would begin the program in July 2008. In May 2008, the Commission issued a Notice of Proposed Rulemaking to consider the application for the revised tariff that Pepco and SMPPI had filed in April 2008. Specifically, they sought revisions to hourly pricing, critical-peak pricing and critical rebate rates in effort to make sure "that the average residential customer will not pay more on the program's pricing plans than the average residential customer pays on the standard offer service ('SOS') pricing plan."

  Pepco initially filed its proposal for what became PowerCentsDC to the DC Public Service Commission in June 2006. (PowerCentsDC was called SmartPowerDC until the name changed via a July 2007 proposed compliance tariff.) Participation in the pilot is limited to approximately 1,200 homes. Participants will be selected randomly. Participants have three pricing options: (1) Hourly Pricing; (2) Critical-Peak Pricing; or (3) Critical Peak Rebate. The program is to provide "statistically valid results that will be used to determine the effectiveness of smart meters." The Commission directed in the January 2007 Order that the SMPPI program measure the following: (1) customer reduction in electricity consumption during peak times; (2) customer changes in overall consumption; (3) customer satisfaction with different pricing options and technologies; (4) usefulness of the selected technologies; and (5) value of presenting additional pricing information to customers.

- In March 2006, the Commission established the Demand Response Working Group tasked with filing a report within 60 days. In May 2006, the Demand Response Working Group filed its report, in which it concluded:

  > "The two key concerns shared by all of the DR Working Group members were program costs and time for implementation. Both of these are dependent upon the scale and scope of the program the Commission decides to implement. The Working Group discussed how any new DR program should be funded and reached a general consensus that the funding would be from all District of Columbia electricity customers. The DR Working Group failed to reach a consensus position regarding the feasibility of implementing a near-term additional DR program in the downtown area of the District of Columbia in response to the current supply situation."
  >
  > "As previously noted, all Working Group members generally supported longer-run demand response initiatives in the District of Columbia, assuming that the costs are not excessive."

  In September 2006, the Commission accepted the Demand Response Working Group's report. No subsequent activity of the Demand Response Working Group was identified for this report.

Florida

Regulatory:

- In April 2007, the Florida Public Service Commission decided not to adopt PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005. According to the Commission, it has been committed to the PURPA standard—as well as the "spirit of efficiency, conservation, and customer options which underlay the…standards"—since the 1981 issuance of the PURPA standards. For its EPACT 1252 proceeding, the Commission surveyed Florida utilities, even those not subject to EPACT 2005, and found that they have "considered and implemented time sensitive rates and load management programs that comply with the spirit of Section 1252." Therefore, the Commission finds Florida to be in compliance. Furthermore, it states that adopting PURPA Standard 14 could mandate programs that are "not cost effective for the general body of ratepayers."
- In December 2007, the Florida Energy Commission—created by the Florida Legislature in 2006—pursuant to its mandate delivered a series of energy policy recommendations to the Legislature via its "2007 Florida Energy Commission Report to the Legislature." Two of the recommendations are of interest:
  - Establish Advanced Metering Systems and Pricing Strategies: "It is recommended that the Legislature direct the Public Service Commission to develop regulatory policies that encourage the deployment of advanced metering systems and innovative pricing strategies."
  - Establish Priority Order of Preference for Supply/Demand Options: "[The state legislature should] direct the Florida Public Service Commission to provide guidance to the state's generating utilities through a "priority order of preference" for future supply and demand options based on the guiding principles of reliability, efficiency, affordability, and diversity. In developing the priority order of preference the Public Service Commission should specify that energy efficiency and demand response constitute the preferred options in addressing Florida's future energy needs."

  In addition to filing its report with the Legislature, the Florida Energy Commission provided legislators with draft legislation that would put into effect its recommendations for demand response and smart metering. It appears that this draft legislation informed the process of drafting two bills later introduced into the Florida Legislature, SB 1544 and HB 7135.

Legislative:

- The 2008 Florida Legislature is considering two bills that would reduce peak demand and direct the Florida Public Service Commission to establish a renewable portfolio standard. While the bills—SB 1544 in the Senate and HB 7135 in the House—are not identical, they both contain the following language about reducing peak demand:
  - "Reduce the need for new power plants by encouraging end-use efficiency, reducing peak demand, and using cost effective alternatives."
  - "The [Florida Public Service Commission] shall adopt appropriate goals for increasing the efficiency of energy consumption and increasing the development of demand-side renewable energy systems specifically including goals designed to increase the conservation of expensive resources…to reduce and control the growth rates of electric consumption, and to reduce the growth rates of weather-sensitive peak demand, and to encourage development of demand-side renewable energy resources."

Georgia

Regulatory:

- Via an August 2006 Order, the Georgia Public Service Commission said it would consider PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005 vis-à-vis Georgia Power's 2007 Integrated Resource Plan (IRP) in a proceeding established for the IRP. Therefore, it directed Georgia Power to address EPACT 1252 in its 2007 IRP. In January 2007, Georgia Power filed its 2007 IRP in which it outlined plans to introduce three new demand response tariffs—critical-peak pricing for large industrial customers, critical-peak pricing for residential customers, and TOU pricing for residential customers. In July 2007, the Commission Staff filed its recommendations regarding EPACT 1252:

  > "The Staff recommends that the Commission find that the Company has had certain demand response programs such as RTP for large commercial and industrial customers and a Pilot A/C cycling program for residential customers in place for many years. The Company has also informed the Commission that it has begun the deployment of smart meters in conjunction with their plans to introduce three new load-control programs in its 2007 base rate filing which will be addressed by many parties. The Staff recommends that the Commission direct the Company to make a filing that details the plans for these three new programs (or show where this information is located in their 2007 rate case filing) and provide an update on the status of the deployment of the smart meters."

  In August 2007, the Commission adopted wholesale its Staff's recommendations about EPACT 1252.

  Earlier, in July 2007, the Commission reconvened its DSM Working Group—created in another docket—"for the purpose of examining whether how [sic] Georgia Power has calculated various resources using the RIM test and to see if it was calculated in a manner consistent with the most recent version of the California Standard Practice Manual in preparing the Plan, to evaluate whether demand side activities should be reviewed on a program or measure basis, and to consider any tools other than those already used by the Company for evaluating DSM programs." The DSM Working Group filed its report with the Commission in May 2008—while it mentions demand response, the focus seems to be on efficiency.

Hawaii

No legislative or regulatory policy activity related to demand response was identified for this report.

Idaho

Regulatory:

- In January 2007, the Idaho Public Utilities Commission decided not to adopt PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005. It noted in its Order declining adoption that it "will continue to implement cost-effective smart metering program[s] for each utility [in Idaho] on a case-by-case basis." The Commission said that its decision was based on its belief that smart metering regulation should be tailored to the needs of individual utilities and only implemented when cost-effective. It also agreed with its Staff's position that utilities "would be unable to implement across-the-board Smart Metering within the time period contemplated by the federal standard." The Commission summarized its position with this statement:

  > "While we concur with the intent of the standard, its ubiquitous scope and implementation timeline are unrealistic…. We find that requiring smart meters across the board for each utility has not been demonstrated to be cost effective. Although we

decline to adopt this federal standard, we find that the Commission embraces the spirit of the standard. In particular, we have implemented Smart Metering communication programs for all three utilities."

- In July 2007, the Commission approved a load management pilot program proposed by Avista Utilities. The program is for residential and commercial customers—participation in it is voluntary—and will last two years. Through it, Avista will use programmable thermostats and other demand response devices to exert direct load control over a number of different appliances.

  At least four times a year, Avista will remotely control the appliances in order to reduce the participants' energy consumption during peak events. (Peak events will last from four to six hours.) The utility will provide incentives for customer participation. The incentives are appliance-specific and will apply to participants variably. They include:

  - Upgraded equipment
  - Inspection of heating, ventilating, and AC (HVAC) system
  - Audit of all equipment controlled by the demand response switch
  - $10/month credit during July, August, December, January, and February

  Avista will provide the Commission with periodic updates of the pilot as well as a final report after two years. The Commission's Staff encourages the utility to also "measure kilowatt hours (kWh) as well as to examine whether energy use is reduced or shifted to other times."

- In August 2008 Idaho Power filed an application with the Idaho Public Utilities Commission requesting a Certificate of Public Convenience and Necessity that would authorize the utility's AMI deployment plan. (Idaho Power initially filed the plan in August 2007, pursuant to a Commission Order in a different proceeding; the August 2008 application simply seeks approval of that plan.) Idaho Power's plan is to convert, over three years and at a capital cost of up to $71 million, "nearly all" its customer's current meters to smart meters. The capital cost "does not include the accelerated depreciation of the existing metering infrastructure or the operation and maintenance benefits associated with the deployment of the new AMI technology." The utility intends to begin the project in January 2009.

- In September 2008, the Commission issued an Order providing notification of Idaho Power's application as well as soliciting comments about it. Unless it receives comments requesting that hearings be held, the Commission will consider the utility's filing via a "Modified Procedure." Through a Modified Procedure, the Commission would not hold hearings about Idaho Power's application but would instead communicate with parties to the proceeding through "written submission." Comments are due in December 2008.

Legislative:

- In January 2007, the Idaho Legislature issued the "2007 Idaho Energy Plan," which "establishes conservation, energy efficiency, and demand response as the highest priority resource for Idaho, and local renewable resources as the second highest priority." The Legislature's Legislative Council's Interim Committee on Energy, Environment, and Technology developed the plan.

Illinois

Regulatory:

- Via a June 2007 Order, the Illinois Commerce Commission found that Illinois utilities have complied with state standards that satisfy the "federal comparable standard test" relative to PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005. The EPACT 1252 proceeding is still open, however, as the Commission said, it needs to determine "whether it is appropriate to require utilities to provide time-based meters to all customers." No subsequent activity in the proceeding was identified for this report.

- In January 2008 Commonwealth Edison filed a smart grid proposal with the Illinois Commerce Commission. In September 2008, the Commission issued an Order in which it approved a rate increase of about $270 million for ComEd that would fund, in part, the first phase of the utility's smart grid project, including the deployment of 200,000 smart meters. The Commission also directed its Staff and ComEd to establish an AMI-workshop process and the Statewide Smart Grid Collaborative.

  The AMI workshops are to help set the "goals, timelines, evaluation criteria and Phase 0 technology selection criteria" for ComEd's smart grid project. Since ComEd's deployment of the initial phase of the project depends on the work of the AMI workshops, the workshop series is expected to begin and conclude within six months.

  Meanwhile, the Statewide Smart Grid Collaborative is to "develop a strategic plan to guide deployment of [the] smart grid in Illinois, including goals, functionalities, timelines and analysis of costs and benefits." The group's effort will culminate in a report to the Commission that recommends smart grid policies. The Commission, in turn, will open a proceeding to consider the report and its implications for developing the smart grid in Illinois. The Statewide Smart Grid Collaborative is to be "conducted within twenty-four months" of October 2008.

Legislative:

- In August 2007, Governor Blagojevich signed legislation that directs utilities to reduce peak demand by 0.1% over the prior year, for ten years, by implementing cost-effective demand response programs (Senate Bill 1592). This mandate began in June 2008 and requires utilities to file a demand response plan with the Illinois Commerce Commission every three years that demonstrates their efforts to comply with the legislation. (Ameren Illinois and Commonwealth Edison filed these plans in November 2007.)

  The new law also creates the Illinois Power Agency, whose charter is to develop annual electricity procurement plans for the Commission and to report annually to the General Assembly about, among other things, utilities' demand response programs.

Indiana

Regulatory:

- In August 2007, the Indiana Utility Regulatory Commission decided not to adopt PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005. The Commission's rationale for declining adoption of the PURPA standard is outlined in the last two paragraphs of its August 2007 Order:

  > "Based on our review of the record in this Cause, we find that the Respondent utilities' contention that Indiana's present relatively low rates for electricity; the associated costs for implementation of such programs; and, the purported uncertainty regarding potential benefits, offers a short-sighted view of demand response that only serves

to demonstrate that more needs to be done now with respect to long-term planning and implementation of demand response and conservation programs. The failure to take a long-term view of the issues distorts the cost\benefit analysis of demand response programs; ignores the real possibility of increasingly stringent environmental requirements that may impact electricity generation in the State; and, fails to address costs associated with the future construction of generation. Each of these items will only come at an increased cost for electricity."

"Therefore, while we find and conclude that it is not appropriate to adopt the standards set forth in Section 1252 of EPActO5 (codified at 16 U.S.C. 2621(d)), this conclusion is due in large part to the current lack of a solid foundation of demand response programs in the State from which such an action would constitute a logical and evolutionary next step. While the Commission does consider it appropriate to ensure that every jurisdictional electric utility in the State of Indiana be prepared to offer advanced technologies to their customers, this cannot be accomplished from a standing start. Accordingly, we find that jurisdictional electric utilities must take steps now to ensure the creation of a solid foundation of demand response programs state-wide. This can be accomplished through the examination of the demand response issues within their respective Integrated Resource Plans; future evaluation and requests for consideration of such programs by the Commission; and, continued discussions and collaboration with customers, and the OUCC regarding the development of effective programs, including pilot programs, in each jurisdictional utility's service territory."

- Since July 2004, the Commission has had a proceeding open to consider the effectiveness of DSM programs. In April 2008, the Commission issued an Order in which it announced the beginning of Phase II of the proceeding. Phase II is to "culminate in the development of the framework necessary to allow the parties to fully addresses, in a quantifiable and systematic way, the very specific shortcomings with respect to DSM." The Commission expects that the parties to the proceeding will work collaboratively to that end. Phase II also will feature technical workshops, through which the parties are to investigate, among other things, "Issues identified in the Energy Policy Act of 2005 and the Energy Independence and Security Act of 2007, including consideration of new technologies such as automated metering and potential cost recovery issues associated with the development of new DSM Programs."
- In September 2008, the Commission initiated a proceeding to investigate end-use customer participation in the demand response programs of Midwest ISO and PJM. In its initial Order, the Commission outlined the scope of the proceeding:
  - "An investigation is hereby commenced to allow the Commission to consider and review any and all matters associated with an Indiana end-use electric customer's participation in demand response programs offered by the Midwest IS0 or PJM Interconnection."
  - "All regulated electric utilities operating within the State of Indiana shall be made Respondents in this Cause and shall be served with a copy of this Order."

  In October 2008, the Commission held a preliminary hearing and prehearing conference to set the proceeding's schedule. Later in October 2008, the Commission issued an Order announcing the procedural schedule:
  - Technical Conferences: October and December 2008; January 2009
  - Initial Filing Date: February 2009
  - Responsive Filing Date: March 2009
  - Evidentiary Hearing: April 2009

Iowa

Regulatory:

- In March 2007, the Iowa Utilities Board decided not to adopt PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005. The Board determined that mandating deployment of smart meters was not cost-beneficial. Furthermore, the Board decided that it is difficult to regulate a single standard for advanced metering, writing: "One size apparently does not fit all." The Board, however, directed its Staff to discuss the possibilities of smart meter pilot programs with the utilities that were party to this proceeding. It plans to review, in each utility's rate case, whether current rates send accurate price signals to customers.
- In June 2007, the Board opened a proceeding to study utility-sponsored energy efficiency programs—including load management. The Board opened the case in response to House File 918, which the Iowa General Assembly passed in 2007. In January 2008, the Board filed two reports with the General Assembly—"The Status of Energy Efficiency Programs in Iowa" and the results of its 2007 survey of residential utility customers. Both documents discuss demand response.

Legislative:

- In January 2008, legislation was introduced into the Iowa General Assembly to establish an energy-efficiency portfolio standard (Senate File 2083). The standard would be statewide energy savings of 1.5% per capita per year from 2011 through 2021. The bill also provides for a load management analysis:

  > "The Iowa utilities board, in conjunction with the office of consumer advocate, shall assess the effectiveness of load management practices and approaches currently employed by public utilities in this state, including the accuracy of load demand projections in comparison to actual usage and the extent to which peak-load management procedures established by utilities…are effective in reducing or limiting peak-load period energy demand and consumption."

Kansas

Regulatory:

- In August 2007, the Kansas Corporation Commission decided not to adopt PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005. The Commission said that it should not mandate smart metering as that would be a "one size fits all" approach and could, as a result, disadvantage some utilities. Instead, the Commission encouraged voluntary pilot programs as the best vehicle for deploying smarting metering and TOU rates. Nonetheless, according to the August 2007 Order, "The Commission strongly encourages the development and implementation of pilot programs introducing smart metering and time-based rates, and time-based technology."
- In December 2007, the Kansas Energy Council released its "Kansas Energy Plan 2008." Smart metering and demand response appear in a section on existing utility-sponsored programs.

Legislative:

- In April 2008, Governor Sebelius vetoed legislation—SB 148—that includes a renewable portfolio standard, an energy efficiency standard, and a mandate for public utilities to develop load management programs. The Senate responded within two weeks by voting to override the veto. The House of Representatives, however, failed to pass a similar motion, and the Governor's vetoed was sustained. The provision related to demand response is as follows:

> "Each public utility shall develop energy efficiency and load management programs which provide information, technical assistance and incentives to each type of customer and customer class to control energy use. No later than July 1, 2010, each public utility shall submit to the state corporation commission a report setting forth the elements of the utility's energy efficiency and load management programs."

Kentucky

Regulatory:

- In December 2006, the Kentucky Public Service Commission decided not to adopt PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005. The Commission's Order declining adoption, however, did include support for TOU rates and critical-peak pricing as well as encouragement for utilities to consider these pricing options. In the same Order, the Commission directed several utilities to develop pilot real-time-pricing programs for their C&I customers and/or finalize proposed residential real-time-pricing pilot programs.
- Per the Incentive for Energy Independence Act, signed in August 2007, the Commission opened a proceeding in November 2007 to examine a series of existing laws related to its authority over public utilities with respect to four energy-regulation issues, including one that concerns "demand-management" and includes discussion of a "rebuttable presumption" in favor of demand resources over new generation. The Commission directed the state's six utilities to file by December 2007 information about their current DSM programs, such as the chosen technology, the number of participants, and M&V protocols. Utilities were also directed to submit any internal reports on the potential of demand response in the state. A public hearing was held in April 2008, and comments about the proceeding were filed in May 2008.

Legislative:

- In August 2007, Governor Fletcher signed renewable-energy legislation—the Incentive for Energy Independence Act (House Bill 1). Section 50 of the bill directs the Commission to examine a series of existing laws related to its authority over public utilities. One provision in the new law the Commission must consider concerns "demand-management" and hints at a rebuttable presumption in favor of demand resources over new generation. The provision in question states:

  > "Eliminating impediments to the consideration and adoption by utilities of cost-effective demand-management strategies for addressing future demand prior to Commission consideration of any proposal for increasing generating capacity."

  The Commission reported its findings and made recommendations to the State Legislature in June 2008[RHS3].

Louisiana

Regulatory:

- In August 2007, the Louisiana Public Service Commission adopted its Staff's April 2007 Final Proposed Rule, which does not specifically adopt or reject PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005. Instead, it states that deployment, implementation, and use of both smart meters and demand response "shall be on a voluntary basis unless otherwise ordered by the Commission." It also provides the framework for utility deployments of smart metering and demand response programs:
  - Utilities will be allowed to deploy demand response and smart metering through pilot programs or through full-scale programs.

- "Utilities will have the opportunity to recover through their approved rates and charges prudently-incurred" costs associated with smart metering or demand response programs.
- While weighing the merits of a proposed smart metering program, the Commission will consider whether the program includes demand response.
- Utilities deploying smart meters will be required to file with the Commission bi-annual reports about the deployment.

The Commission, however, made a slight amendment to the rule: it decided that Section 3.6.9 of the rule will read, "Communication between the meter and its head-end system shall be consistent with an open standards architecture that is compliant with the American National Standards Institute (ANSI)."

Furthermore, because the Staff's Final Proposed Rule included a provision that the Commission's Order adopting the rule should not preclude utilities that have "installed qualifying facilities from seeking recovery under this rule," the Commission directed the Staff to further investigate "pilot program implementation for utilities" and Commissioner Field requested that Staff "consider commercial and industrial pilots, in addition to residential."

Maine

Regulatory:

- In February 2008, the Maine Public Utilities Commission issued a draft resource-adequacy plan —"A Resource Adequacy Plan for Maine: Consideration of Electricity Sector Investment Strategies"—which recommends, among other things, increasing the amount of demand response. It says:

  > "Although additional resources are not needed per se in Maine, incremental demand-response should have a positive effect under almost all future market conditions. Indeed, an increase in peak demand relative to average demand due to air-conditioning penetration suggests increasing needs for peaking capacity and/or demand responses to meet those super peak hours that only occur a few hours a year. Therefore, we recommend that demand response be encouraged to the maximum extent possible given its cost-effectiveness."

  The draft plan was developed to meet the requirements of Maine's Energy Independence and Security Act (LD 2041). Comments about the plan were filed in March 2008.

Legislative:

- In June 2006, Governor Baldacci signed Maine's Energy Independence and Security Act, which gives permission to the Maine Public Utilities Commission to incorporate cost-effective demand response and energy efficiency into standard offer supply (LD 2041).

Maryland

Regulatory:

- In February 2007, the Maryland Public Service Commission deferred its decision about whether to adopt PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005. It wrote:

  > "…the Commission hereby advises its jurisdictional electric utilities that it will not direct the wholesale implementation of the above-mentioned standards at this time. The Commission will continue to evaluate the standards and other demand response measures through its work group and any specific utility filings with the Commission. It will consider the working group's efforts and conduct further proceedings in this matter, if necessary, within two years of the effective date of [the Energy Policy] Act."

- In January 2008, the Maryland Energy Administration (MEA) presented its "Maryland Strategic Electricity Plan" to Governor Martin O'Malley. The MEA prepared this package of legislative and policy recommendations at the Governor's behest and in response to discussions at the Maryland Energy Summit in July 2007. The MEA wrote:

  > "There is no 'silver bullet' that will enable Maryland to solve these problems overnight. This Plan should be viewed as 'silver buckshot'—a series of measures that cumulatively will promote affordable, reliable and clean energy for Maryland."

  The "Maryland Strategic Electricity Plan" makes 19 recommendations, including the introduction of state legislation requiring the Maryland Public Service Commission to determine whether demand response and smart meters are cost effective in reducing peak demand. Reducing peak demand is also a goal of several other recommendations, including:

  - Use RGGI Revenues to Create a "Strategic Energy Investment Fund."
  - Require that MEA use the energy fund to promote energy efficiency, support renewable energy, and stimulate Maryland's emerging clean energy industry: With this fund, the MEA should implement cost-effective energy efficiency programs to reduce statewide electricity consumption and peak demand.
  - Codify the EmPOWER Maryland Goals: Legislatively codify the goal of reducing overall electricity consumption and peak demand by 15% of 2007 levels by 2015. (The Governor set the EmPOWER goals in July 2007.)
  - Create utility-implemented electricity savings targets: Maryland should enact legislation requiring utilities to implement performance-based programs to reduce electricity consumption and peak demand.
  - Evaluate smart meters and smart grid technology: Legislation should require the Commission to evaluate whether "smart meters" and "smart grid" technology, including TOU and critical-peak pricing, are cost effective in reducing consumption and peak demand, and issue a report to the General Assembly by December 1, 2008.
  - Decouple Utility Profits from Sales Volume.
  - Strengthen Maryland's Renewable Portfolio Standard (RPS).
  - Evaluate creating a Maryland Power Authority and other options to satisfy peak load.

- In May 2008, the Commission held a public conference with the purpose of gathering information about select issues regarding the implementation of the EmPower Maryland Energy Efficiency Act of 2008. (The EmPower Maryland Energy Efficiency Act requires the Commission to evaluate the cost effectiveness of smart meters and a smart grid, and it allows the Commission to mandate the implementation of cost effective smart meter or smart grid technologies.) The Commission solicited comments in preparation for the conference by attaching a list of questions to its April 2008 announcement of the meeting. (Comments on the questions were due in May 2008 and are now posted online.) Several of these questions stand out:

- "Should the Commission adopt one test as the primary evaluation of cost effectiveness [of demand response]?"
- "To the extent [the energy efficiency, conservation, and demand response] plans currently under consideration may not satisfy the EmPower Maryland requirements, what issues are raised if the Commission approves the current plans in whole or in part?"
- "Should the Commission proceed with its consideration of the EE&C proposals currently under review, or should the Commission defer consideration of all electric company EE&C proposals pending the filing of plans under the provisions of the EmPower Maryland Act?"
- The EmPower Maryland Act requires the Commission to evaluate the cost effectiveness of "smart meters" and a "smart grid" and allows the Commission to require the implementation of cost effective smart meter or smart grid technology. This raises two questions:
    - Can the EmPower Maryland goals be achieved without smart meter or smart grid technology?
    - If not, how should the Commission integrate its evaluation of smart meter and smart grid technologies with its monitoring of approved demand response programs and its review of utility EmPower Maryland plans?
- "Should the [peak-demand reduction] plans to be filed September 1, 2008 in compliance with these sections address only targets for 2011 or should they also address the 2013 and 2015 targets [as set by the EmPower Maryland Act]?"

- In September 2008, Maryland utilities complied with the EmPOWER Maryland Energy Efficiency Act of 2008 by filing with the Maryland Public Service Commission "proposals for achieving the electricity savings and demand reduction targets specified" in the law. (EmPower Maryland mandates a 15% reduction in peak demand by 2015; in August 2008 the Commission posted utility-specific reduction targets on its website.) The Commission then opened a separate proceeding for each utility that filed a plan. In each of the proceedings, the Commission solicited comments and scheduled stakeholder meetings and hearings for October and November 2008.

  A brief description of each utility's plan follows.

  Allegheny Power

  In addition to 13 energy efficiency programs, Allegheny Power proposed a pilot program to deploy demand response via "Advanced Utility Infrastructure (AUI) technology." Through the program, the utility would offer demand response and "smart grid technology" to 1,140 of its customers.

  Baltimore Gas & Electric

  BG&E proposed a set of energy efficiency programs that are to reduce peak demand by 478 MW by 2015. BG&E did not propose any demand response programs. It explained in its filing that the Commission has already approved two of its demand response programs (PeakRewards and the Interruptible Load for Reliability programs) and that it is conducting a demand response pilot program (Smart Energy Pricing). BG&E also argued that it would be "inappropriate to speculate on the program details" of the pilot.

Furthermore, BG&E claimed that its two approved demand response programs "are projected to provide sufficient demand reduction to meet the 15% per capita demand reduction goal."

Pepco Holdings, Inc. (PHI): Pepco and Delmarva Power & Light

PHI proposed a host of programs to meet the EmPOWER Maryland goals, including several demand response initiatives. These initiatives are "designed specifically to participate in available demand response market opportunities within the PJM capacity and energy markets." (They also are designed to interface with PHI's planned AMI deployment, which is to be complete by summer 2011). The proposed demand response programs are:

- Residential Direct Load Control Program: Through this program, which the Commission approved in April 2008, PHI will install remotely-controllable smart thermostats in the homes of participating customers. It also will attach direct-load-control switches to customers' AC units. PHI intends to integrate these technologies into its planned AMI deployment in order to use the AMI to measure and verify consumption data relative to the use of the technologies.

- Non-Residential Direct Load Control—Smart Thermostat Program: Through this program PHI would provide remotely-controllable smart thermostats to its small commercial, government, institutional, and industrial customers and would use the devices to deploy direct load control. PHI intends to integrate the smart thermostats with its planned AMI deployment in order to use the AMI to measure and verify consumption data relative to the use of the thermostats.

- Non-Residential Internet Platform for Load Curtailments: Through this program, PHI would provide an "Internet platform" to its commercial, government, institutional, and industrial customers in order to motivate their participation in PJM's demand response programs. It also would provide via the web portal "hourly customer energy data (daily or monthly depending upon existing metering), hourly Pepco Zonal Locational Marginal Prices (LMPs) for energy, and load reduction calculations (hourly energy savings)." PHI intends to use its planned AMI deployment to measure and verify consumption data.

Collectively, Pepco's proposed programs would reduce 2011 peak demand by 509 MW (thereby achieving 174% of the EmPOWER Maryland peak-demand reduction goal for 2011) and 2015 peak demand by 780 MW (achieving 115% of the 2015 goal).

DP&L's proposed programs are to reduce 2011 peak demand by 91 MW (achieving 108% of the EmPOWER Maryland goal for 2011) and 2015 peak demand by 230 MW (achieving 102% of the EmPOWER Maryland goal for 2015).

Southern Maryland Electric Cooperative

Southern Maryland Electric Cooperative (SMECO) proposed 15 programs, including several for demand response and AMI:

- Virtual Peaking Capacity Program: Through this program—to be called "SMECO Cool Sentry"—SMECO would deploy direct load control through smart thermostats and direct-load-control switches it would provide to participating customers. SMECO expects 40,000 of its customers would participate in the program by 2011 and that their participation would reduce demand by 50 MW. The utility anticipates that by 2018 60,000 customers would participate, reducing demand by 75 MW.

- TOU Rate Program: SMECO said that "TOU rates are now appropriate" to be included in its rate structure, and it proposed to make a filing requesting such rates. Its filing is to include its visions for how to roll out TOU rates.

- AMI Intelligent Grid Program: SMECO said it is preparing a plan to deploy AMI "within the overall context of building an Intelligent or Smart Grid." Its filing includes a roadmap for how to deploy AMI.

- Since January 2007, the Commission has had open a proceeding through which it is investigating "advanced metering technical standards, DSM cost effectiveness tests, DSM competitive neutrality, and recovery of costs of advanced meters and DSM programs." In June 2007 the Commission, as part of this proceeding, created the AMI/DSM Collaborative. In September 2007 the Commission issued an Order in which it called for utilities to file "comprehensive energy efficiency, conservation and demand reduction plans" that met specific consumption-reduction goals by 2015 and included "aggressive" peak-demand reduction proposals effective by 2011. Utilities have since filed such plans and made alterations to them per Commission requests. The most recent news in the proceeding is that in June 2008 the Commission's AMI/DSM Collaborative reviewed Pepco and Delmarva Power & Light's (DP&L) most-current energy efficiency and conservation proposals. The review was intended to allow a "thorough stakeholder understanding" of the updated proposals in order to help stakeholders comment on them before the Commission considers their adoption. These proposals include Pepco and DP&L's responses to the Commission's March 2008 data request it made vis-à-vis the utilities' original proposal filed per the September 2007 Order.

- In July 2007, the Commission held a Planning Conference on Maryland's Energy Future where demand response was one of the topics discussed. Comments filed in anticipation of the conference, as well as presentations given at it, are available on the Commission's website. In November 2007, and in response to the Planning Conference, the Commission scheduled a "workgroup session" to facilitate discussion on (1) transmission siting and construction, (2) new generation, and (3) conservation and efficiency programs. This is the last action in the proceeding identified for this report.

  Although the Commission opened a proceeding specific to its Planning Conference on Maryland's Energy Future, the conference is a result of a May 2007 Order in a different proceeding. It also serves to fulfill the Commission's responsibility to the Maryland General Assembly as outlined in Senate Bill 400 (Chapter 549, Acts of 2007).

- In July 2008, the Commission held a "legislative-style hearing" to discuss whether utilities should be given new or additional incentives to implement energy efficiency, conservation and demand response programs and, if so, how such incentives should be structured. As the Commission noted in its June 2008 announcement of the hearing, the goal of the conference was to gather information that could guide the Commission's policy actions in this area. In the announcement the Commission wrote:

  > "Before initiating a contested proceeding or rulemaking, the Commission institutes this forum to permit stakeholder to express views that will enable the Commission to better assess the type of proceeding necessary, if any, to develop regulation that provide threshold standards and guidelines to structure incentives for utilities that implement EE&C or demand response programs."

  To inform the hearing's discussions, the Commission also solicited comments in its June 2008 announcement. The comments that were filed, including those of the Commission's Staff, are available on the Commission's online.

- The Commission, in July 2008, issued an Order in which it directed investor-owned utilities (IOUs) to file by October 2008 an "evaluation of a long-term procurement plan for providing SOS [standard offer service]" to residential and small commercial customers over a period up to fifteen years in length. The Commission, furthermore, provided parameters for creating the plan. According to them, the IOUs are to consider demand response and the smart grid as potential resources:

> "The IOUs should evaluate a variety of different resource mixes, including new generation, generation upgrades, demand response programs, PSC-approved residential energy efficiency programs, potential or proposed commercial and industrial energy efficiency programs, implementation of a smart grid system and upgrades to the transmission and distribution system, to name a few. The procurement plans should incorporate some component of longer-term (more than five years), medium-term (one to five years) and shorter-term (one year or less, including spot market purchases, if applicable) procurements. The IOUs should specifically address the extent to which each resource mix will help to meet current objectives for EmPOWER Maryland, Maryland's Renewable Portfolio Standard, Maryland's commitments to the Regional Greenhouse Gas Initiative, and PJM's reliability requirements as they apply to Maryland."

The parameters also include these directives:

- "One or more of the resource mixes evaluated by the IOUs should include a proposal for new IOU-owned generation, including a description of the generation type, estimated installed capacity and fuel type of such generation."
- "The IOUs should also identify assumptions for, and evaluate the effect of, any new transmission that is proposed to be added to the region's transmission network during the study term…."
- "The IOUs should forecast expected annual costs for each portfolio mix…and the distribution of cost outcomes around those expected costs. This should incorporate forward market prices, pricing distributions that describe price volatilities, load characteristics and correlation factors (load to price, fuel types, etc.)."
- "The IOUs should recommend which portfolio mix best balances the competing mandates set forth in Senate Bill 400, that is, "a portfolio of electricity supply that provides electricity at the lowest cost with the least volatility."

The Commission opened this proceeding in August 2007—pursuant to Senate Bill 400, signed by Governor O'Malley in May 2007—in order to "examine various options" for providing standard offer service to residential and small commercial customers. Senate Bill 400 directed the Commission to assess standard offer service and to ensure that customers receive it "at the best possible price" and "with the least volatility."

Legislative:

- In April 2008, Governor O'Malley signed two bills:
  1. The EmPower Maryland Energy Efficiency Act sets efficiency and peak-demand reduction portfolio standards, mandates utilities to file demand response plans, and directs the Maryland Public Service Commission to consider whether smart meters are "are cost–effective in reducing consumption and peak demand of electricity" (SB 205/HB 374).
  2. The Regional Greenhouse Gas Initiative—Maryland Strategic Energy Investment Program Act creates the Maryland Strategic Energy Investment Program (housed in the Maryland Energy Administration), which will fund demand response programs (HB 368).

Massachusetts

Regulatory:

- In June 2007, the Massachusetts Department of Public Utilities (DPU) opened a proceeding to investigate rate structures and revenue-recovery mechanisms that will facilitate "efficient deployment" of demand resources—including demand response. In July 2008, the DPU issued an Order announcing its decision to decouple utility rates. In the Order, the DPU discussed how decoupled rates will facilitate demand response, among other demand-side strategies:

  > "[Decoupled rates] will also provide distribution companies with better financial incentives to pursue a cleaner, more efficient energy future consistent with the recently enacted legislation…An Act Relative To Green Communities ('Green Communities Act'). Today's Order paves the way for the aggressive expansion of demand resources (i.e., energy efficiency, demand response, combined heat and power, and renewable generation) in Massachusetts in a manner that fully maintains and enhances fundamental and long-standing Department precedent on ratemaking principles and consumer protections for all consumers of electricity and natural gas in the Commonwealth."

  The DPU began its investigation of decoupling, in fact, with the specific intention of encouraging the use of demand-side resources:

  > "We initiated this proceeding to determine what, if any, changes are necessary to current ratemaking practices in order to reduce the financial disincentives that electric and gas companies face regarding the deployment of demand resources in their service territories."

  According to the July 2008 Order, utilities are to have "operational decoupling plans" by the end of 2012.

  In response to the July 2008 Order, multiple parties to the proceeding, including the Attorney General of Massachusetts, filed motions for "reconsideration and/or clarification." The DPU issued an Order in October 2008 denying these motions for reconsideration.

- In November 2006, the Massachusetts Department of Telecommunications & Energy (the agency that became the Department of Public Utilities in April 2007) opened a proceeding in response to an October 2006 request by the Massachusetts Division of Energy Resources (DOER) to investigate "the potential benefits of implementing dynamic pricing for all basic/default customers in Massachusetts." Specifically, the DOER wanted to consider relative to basic/default service the following:

  - Hourly, wholesale rates for large C&I customers
  - TOU rates for residential, and small and medium C&I customers
  - Other demand response rates, such as critical-peak pricing and variable peak pricing

  In August 2008, the DPU issued an Order in which it announced that it would not open an investigation of dynamic pricing as the DOER requested in October 2006. In its Order, the DPU explained its decision:

  > "In our recent Order implementing revenue decoupling for all gas and electric distribution companies in Massachusetts, the Department stated that we intend to establish a regulatory environment that encourages the aggressive expansion of demand resources in Massachusetts in a manner that 'fully maintains and enhances fundamental and long-standing Department precedent on ratemaking principles and

consumer protections'…. In addition, the Department is now mandated to implement a number of important policies and programs by Chapter 169 of the Acts of 2008 ('Green Communities Act'). For example, Section 85 of the Green Communities Act requires the Department to review and approve pilot programs that include time of use ('TOU') or hourly pricing for commodity service, that will be filed by each electric distribution company no later than April 1, 2009. As these programs could inform DOER's proposal to investigate the costs and benefits of dynamic pricing, the Department will not open an investigation into dynamic pricing at this time."

- In December 2006, the Massachusetts Department of Telecommunications & Energy (the agency that became the Department of Public Utilities in April 2007) opened—in response to a petition from the DOER—a proceeding to investigate the possibility of establishing an electricity efficiency performance standard (EPS) as a component of basic/default service. As outlined in its December 2006 petition, the DOER proposed that all electric-distribution companies be mandated to purchase a minimum percentage of their basic service supply through cost-effective energy-efficiency resources. The DOER's proposal was for 0.25% (78 gwh) of the 31,211 gwh of expected default power to come from energy savings in 2008 and for a 0.25% annual increase through 2013. The DOER also submitted that demand response should not be eligible in an EPS. Consider this excerpt from the DOER's December 2006 petition:

  "Demand response projects (e.g. short-term load shifting and/or load curtailment) should not be eligible to participate in an EPS. Their contributions to overall energy savings would be negligible and could not be fairly compared with the cost per kWh of efficiency resources."

  Comments were filed, but no subsequent activity in this proceeding was identified for this report.

- In August 2008, the Massachusetts Department of Public Utilities (DPU) issued an Order in which it announced that it would not open an investigation of dynamic pricing as the DOER requested in October 2006. (The DOER asked that the Department of Public Utilities look into the "potential benefits of dynamic pricing for all basic service customers in Massachusetts.") In its Order, the Department of Public Utilities explains its decision:

  "In our recent Order implementing revenue decoupling for all gas and electric distribution companies in Massachusetts, the Department stated that we intend to establish a regulatory environment that encourages the aggressive expansion of demand resources in Massachusetts in a manner that 'fully maintains and enhances fundamental and long-standing Department precedent on ratemaking principles and consumer protections'…. In addition, the Department is now mandated to implement a number of important policies and programs by Chapter 169 of the Acts of 2008 ('Green Communities Act'). For example, Section 85 of the Green Communities Act requires the Department to review and approve pilot programs that include time of use ('TOU') or hourly pricing for commodity service, that will be filed by each electric distribution company no later than April 1, 2009. As these programs could inform DOER's proposal to investigate the costs and benefits of dynamic pricing, the Department will not open an investigation into dynamic pricing at this time."

Legislative:

- In July 2008, Governor Patrick signed into law SB 2768, the "Green Communities Act," which includes demand response, smart metering, and smart grid provisions, as is reflected in the language of the new law:

SECTION 7

Establishes a "cap & trade" program whose revenues would fund, among other things, promotion of demand response.

SECTION 11

- Requires that electricity needs are met first by "all available energy efficiency and demand reduction resources that are cost effective or less expensive than supply…."
- Directs "electric distribution companies and municipal aggregators with certified efficiency plans" to jointly file every three years an "electric efficiency investment plan" that includes: "(i) an assessment of the estimated lifetime cost, reliability and magnitude of all available energy efficiency and demand reduction resources that are cost effective or less expensive than supply; (ii) the amount of demand resources, including efficiency, conservation, demand response and load management, that are proposed to be acquired under the plan and the basis for this determination; (iii) the estimated energy cost savings that the acquisition of such resources will provide to electricity and natural gas consumers, including, but not limited to, reductions in capacity and energy costs and increases in rate stability and affordability for low-income customers; (iv) a description of programs, which may include, but which shall not be limited to: (A) efficiency and load management programs; (B) demand response programs;…(viii) the estimated amount of reduction in peak load that will be reduced from each option and any estimated economic benefits for such projects, including job retention, job growth or economic development"
- Directs the Department of Environmental Protection to "appoint and convene an energy efficiency advisory council," which is to "seek to maximize net economic benefits through energy efficiency and load management resources and to achieve energy, capacity, climate and environmental goals through a sustained and integrated statewide energy efficiency effort. The council shall review and approve demand resource program plans and budgets, work with program administrators in preparing energy resource assessments, determine the economic, system reliability, climate and air quality benefits of efficiency and load management resources, conduct and recommend relevant research, and recommend long term efficiency and load management goals to maximize economic savings and achieve environmental goals…."

SECTION 85—Smart Grid Provision

"On or before April 1, 2009, each electric distribution company shall file a proposed plan with the department of public utilities to establish a smart grid pilot program. Each such pilot program shall utilize advanced technology to operate an integrated grid network communication system in a limited geographic area. Each pilot program shall include, but not be limited to advanced ('smart') meters that provide real time measurement and communication of energy consumption, automated load management systems embedded within current demand-side management programs and remote status detection and operation of distribution system equipment. On or before April 1, 2009, each electric distribution company shall file a proposal with the department of public utilities to implement a pilot program that requires time of use or hourly pricing for commodity service for a minimum of 0.25 per cent of the company's customers. A specific objective of the pilot shall be to reduce, for those customers who actively participate in the pilot, peak and average loads by a minimum of 5 per cent. The department shall work with the electric distribution companies to identify specific areas of study, and may incorporate and utilize information from past relevant studies or pilot programs. The department shall review and approve or modify such plans on or before August 1, 2010. Plans which provide for larger numbers of customers and can show higher bill savings than outlined above shall be eligible to earn incentives as outlined in an approved plan. The programs filed by the distribution company shall include proposals for rate treatment of incremental program costs; provided, however, that such program costs shall be deemed by the department to be a cost of basic service and recovered in rates charged for basic service. Following the completion of the pilot programs, the secretary of energy and environmental affairs shall submit a report to the joint committee on telecommunications, utilities and energy not later than September 1, 2012 detailing the operation and results of such programs, including information concerning changes in consumer's energy use patterns, an assessment of the value of the program to both participants and non-participants and recommendations concerning modification of the programs and further implementation."

SECTION 97—Demand Response Study Provision

"On or before December 31, 2009, the energy advisory council appointed under section 22 of chapter 25 of the General Laws shall undertake, using third party experts, a study which examines the energy efficiency and demand response programs in the commonwealth, including all public and private funding sources. The study shall include an audit of all existing energy efficiency and demand response programs to identify the costs and benefits associated with such programs. Such third party experts shall not have any contractual relationship with an electric or natural gas distribution company doing business in the commonwealth or any affiliate of such company."

SECTION 116—"Alternative Energy" Portfolio Standard Provision

"(a) It is hereby established that the commonwealth's renewable and alternative energy and energy efficiency goals are as follows:

"(1) meet at least 25 per cent of the commonwealth's electric load, including both capacity and energy, by the year 2020 with demand side resources including: energy efficiency, load management, demand response and generation that is located behind a customer's meter including a combined heat and power system with an annual efficiency of 60 per cent or greater with the goal of 80 per cent annual efficiency for combined heat and power systems by 2020;

"(2) meet at least 20 per cent of the commonwealth's electric load by the year 2020 through new, renewable and alternative energy generation

"(3) reduce the use of fossil fuel in buildings by 10 per cent from 2007 levels by the year 2020 through the increased efficiency of both equipment and the building envelope

"(4) develop a plan to reduce total energy consumption in the commonwealth by at least 10 per cent by 2017 through the development and implementation of the green communities program…that utilizes renewable energy, demand reduction, conservation and energy efficiency. Not later than September 1 of each year, the secretary of energy and environmental affairs shall establish an annual reduction target for the commonwealth for the following calendar year."

Michigan

Regulatory:

- In January 2007, the Michigan Public Service Commission determined that all but two of the qualifying utilities in Michigan already offered time-based rates that satisfied PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005. The Commission, however, did not use language in its January 2007 Order specifically indicating that it was deciding not to adopt PURPA Standard 14.
- In January 2007, the Commission opened a proceeding to consider the time-based-rates filing of Edison Sault, which the utility submitted in April 2007. (The Commission opened this proceeding in response to its EPACT 1252 proceeding, in which it determined that Edison Sault was one of two utilities in Michigan that did not meet the PURPA standard.) In July 2007 the Commission solicited comments about the filing. No subsequent activity in the case was identified for this report.
- In January 2007, the Commission opened a proceeding to consider the time-based-rates filing of the Midwest Energy Cooperative, which the utility submitted in May 2007. (The Commission opened this proceeding in response to its EPACT 1252 proceeding, in which it determined that the Midwest Energy Cooperative was one of two utilities in Michigan that did not meet the PURPA standard.) In July 2007, the Commission approved the Midwest Energy Cooperative's proposed time-based rates.
- In January 2007, the Michigan Public Service Commission presented to the Governor its "21st Century Energy Plan," which recommends demand response and AMI. The Commission then created four working groups to support the plan—two of the groups will consider demand response and the smart grid through, respectively, the "Demand Response Team" and the "Smart Grid Team."
- In June 2007, the Commission opened a proceeding to implement the demand response portion of the "21st Century Energy Plan." In the same Order, the Commission also formed a working group called the Michigan Demand Response Collaborative, which is to facilitate the deployment of demand response. The Commission directed all of the state's regulated utilities to participate in it. The demand response collaborative is to develop pilot programs and "emphasize the use of 'smart' metering, advanced technology, and time-based or real time rate structures." It must also assess the impact of time-based rates on customer demand for electricity.
- In April 2007 the Commission directed its Staff to convene a statewide collaborative on smart grid infrastructure to improve the state's electric grid. The Smart Grid Collaborative, as the group is known, is responsible for establishing evaluation criteria and standards that would trigger pilot programs or broader deployment in Michigan if options appear cost-effective and practical to implement. In March 2008, the Commission added the task of considering plug-in electric hybrid vehicles (PHEVs) vis-à-vis the smart grid to the workload of the Smart Grid Collaborative. In particular, the Smart Grid Collaborative is to develop pilot programs that study PHEVs and will file with the Commission a report about the pilots—the report is due in June 2009. In April 2008, the Smart Grid Collaborative filed a report with the Commission, in which it concludes:

  > "Until the Commission can identify minimum functionality standards for utility rate recovery of AMI investments, Michigan utilities will prudently limit their AMI deployment to a phased technology pilot approach, so as to perform extensive testing, and limit financial risk associated with this major capital expenditure. During this transition period, Staff recommends that the Commission complete a public input process to develop minimum AMI functionality guidelines and criteria for rate recovery by regulated electric utilities."

- In May 2008, the Commission issued an Order in which it allocated grant awards from its Low-Income and Energy Efficiency Fund for the fiscal year beginning October 1, 2007 and ending

September 30, 2008. The Commission awarded $5,000,000 to the University of Michigan, General Motors Corporation, and DTE Energy to support their PHEV research. Specifically, the money is to fund a study of "plug-in hybrid electric vehicles as a Michigan economic development catalyst, the near-term vehicle-utility interface, the mid/long-term vehicle utility interface, and the environmental and electric utility system impacts of PHEVs."

- In July 2008, the Commission issued an Order opening a proceeding to set minimum functionality standards for AMI. The Commission began the proceeding in response to the work of its Smart Grid Collaborative—which it created in a different proceeding in April 2007—and in preparation for AMI pilot programs which utilities plan to launch. As the Commission explained in its July 2008 Order, "With AMI pilots scheduled to commence in 2008, guidance is needed to describe minimum functionality criteria and standards necessary for the rate recovery of this infrastructure development."

  In the initiating Order, the Commission solicited comments about a broad range of developments ranging from AMI enhancements, "which enable demand response programs at a customer level," to distribution- and transmission-level developments, "which improve grid stability, reliability, and resilience." The Commission asked for input in seven areas:

  - Standards/criteria for AMI technologies, functionalities, and deployments
  - Consumer choice of AMI functions
  - Meter data management
  - Depreciation
  - Costs and benefits of AMI
  - Interoperability
  - Security

  Comments were due in August 2008 and are now available on the Commission's website.

  Furthermore, the Commission directed its Staff to develop a report on AMI. The Staff filed its report in October 2008, concluding, "Advanced metering infrastructure initiatives are an important tool to modernize the electricity grid, reduce peak demand and reach energy efficiency goals." In the report—"Staff Report on Minimum Functionality Standards for Advanced Metering Infrastructure"—the Staff reviewed federal and state AMI policies. It also summarized and synthesized the comments filed in August 2008.

Legislative:

- In October 2008, Governor Granholm signed a bill that fosters the deployment of demand response (Senate Bill 213). Key language from the new law follows:

  - "The commission shall do all of the following:
    - "Promote load management in appropriate circumstances.
    - "Actively pursue increasing public awareness of load management techniques.
    - "Engage in regional load management efforts to reduce the annual demand for energy whenever possible.
    - "Work with residential, commercial, and industrial customers to reduce annual demand and conserve energy through load management techniques and other activities it considers appropriate. The commission shall file a report with the legislature by December 31, 2010 on the effort to reduce peak demand. The report shall also include

any recommendations for legislative action concerning load management that the commission considers necessary."

- "The commission may allow a provider whose rates are regulated by the commission to recover costs for load management undertaken pursuant to an energy optimization plan through base rates...."
- "A provider shall file a proposed energy optimization plan [which may include load management, to the extent that it reduces overall energy consumption,] with the commission within the following time period:
  - "For a provider whose rates are regulated by the commission, 90 days after the commission enters a temporary order under section 171.
  - "For a cooperative electric utility that has elected to become member-regulated under the electric cooperative member regulation act…or a municipally-owned electric utility, 120 days after the commission enters a temporary order under section 171."
- "For any year after 2012, an electric provider may substitute renewable energy credits associated with renewable energy generated that year from a renewable energy system constructed after the effective date of this act, advanced cleaner energy credits other than credits from industrial cogeneration using industrial waste energy, load management that reduces overall energy usage, or a combination thereof for energy optimization credits otherwise required to meet the energy optimization performance standard, if the substitution is approved by the commission."

- In October 2008, Governor Granholm signed a bill that directs the Michigan Public Service Commission to set standards for integrated resource plans (House Bill 5524). The new law requires that integrated resource plans address demand response:
  - "The commission shall establish standards for an integrated resource plan that shall be filed by an electric utility requesting a certificate of necessity under this section. An integrated resource plan shall include all of the following:

    "(e) Projected load management and demand response savings for the electric utility and the projected costs for those programs.

    "(f) An analysis of the availability and costs of other electric resources that could defer, displace, or partially displace the proposed generation facility or purchased power agreement, including additional renewable energy, energy efficiency programs, load management, and demand response, beyond those amounts contained in subdivisions (c) to (e)."
- The Michigan Legislature is considering two bills in 2008 that would foster the deployment of demand response and would reduce peak demand.

  1. "Energy Efficient Michigan Act"—House Bill 5525—was introduced in December 2007 and would mandate the Michigan Public Service Commission to establish energy efficiency performance standards and to support load management. Regarding load management, the legislation says:

     "The Commission would have to promote load management in appropriate circumstances, including allowing rate recovery for prudent load management expenditures. 'Load management' would mean 'measures or programs that decrease peak electricity demand or shift demand from peak to off-peak periods.'"

     In April 2008, the Michigan House of Representatives passed the bill and referred it to the Michigan Senate.

In June 2008, the Senate modified and passed the House bill. A conference committee then began to forge a final piece of legislation out of the House and Senate versions of the bill.

2. House Bill 5548 would direct utilities to file with the Commission a renewable energy portfolio for the period 2012–2015. The legislation would grant renewable energy credits, which could offset the need for actual renewable resources, to utilities for deploying renewable energy sources that reduce peak demand. The Commission would calculate the credits according to this formula: "1/5 renewable energy credit for each megawatt hour of electricity generated from a renewable energy system, other than wind, at peak demand time as determined by the commission."

   In April 2008, the Michigan House of Representatives passed the bill and referred it to the Michigan Senate.

   In June 2008, the Senate modified and passed the House bill. A conference committee then began to forge a final piece of legislation out of the House and Senate versions of the bill.

Minnesota

Regulatory:

- In April 2008, the Minnesota Climate Change Advisory Group—created by the Minnesota Department of Commerce and other agencies in response to the Next Generation Act of 2007—issued its final report in which it supports the deployment of smart appliances and the integration of demand response with distributed generation.
- In August 2007, the Minnesota Public Utilities Commission issued an Order in which it decided not to adopt PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005 but decided instead to adopt a modified version of it—which it will apply on a "utility-by-utility basis." This settlement is outlined in four provisions of the August 2007 Order:
  - "The Commission finds, having conducted the investigation required in Section 1252 (b) of the EPAct, that it would not be appropriate at this time to require electric utilities to provide and install time-based meters and communications devices for each of their customers."
  - "The Commission hereby modifies the smart metering standard to include practices that achieve goals similar to smart metering, and which reflect Minnesota utilities' experiences with practices that achieve the same goals as smart metering."
  - "The Commission herein implements the modified standard on a utility-by-utility basis, depending on what practices the utility already has in place."
  - "The Commission finds it appropriate to consult the standard, as modified to reflect Minnesota utilities' experiences, during the review of rate structures of individual utilities on an ongoing basis, during rate cases or at other appropriate times."

  The Commission's Order presents four reasons why it did not adopt PURPA Standard 14 as it was enacted:

  - "First, each of the utilities responding in this matter has at least partially implemented some form of time-variant rates, offering rate schedules in which price varies in relation to variations in cost at different times during the day. Such rates, however, are not often preferred by customers over standard rates. No Minnesota utility has implemented mandatory time-based rate schedules for each of its customers."

- "Second, voluntary participation in utility programs offering time-of-use rates is generally low amongst residential customers, in large part due to the hours of the on-peak period compared to the off-peak period."
- "Third, while the technology currently exists to utilize time-based billing, to require utilities to implement the technology would require for some utilities an across-the-board upgrade of meters and load management infrastructure."
- "Fourth, the utilities requested flexibility, not a one-size-fits-all approach."

Legislative:

- In May 2007, Governor Pawlenty signed the Next Generation Energy Act of 2007, which changes how conservation is measured from the amount spent on conservation to the amount of electricity conserved (House File 436). The law considers load management to be a conservation measure.
- In February 2007, the Governor signed legislation—SF 4—that sets a renewable portfolio standard of 25% by 2025. It requires Xcel Energy to meet a renewable portfolio standard of 30% by 2020.

Mississippi

No legislative or regulatory policy activity related to demand response was identified for this report.

Missouri

Regulatory:

- In a July 2007 Order, the Missouri Public Service Commission decided not to adopt PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005, "finding that the prior state action exemption applies and that no further action is required by the Commission with relation to [EPACT 1252]." The Commission agreed with its Staff's April 2007 "Statement of Position" in which it recommended not adopting PURPA Standard 14 because utilities already provide time-based rates:

  > "Under statutory provision (1) quoted above, the prior state action exemption applies if the State has implemented for such utility the standard concerned (or a comparable standard). Each of the [utilities' existing time-based] rates discussed above is set forth in a tariff authorized and implemented by action of the Commission. Therefore, the prior state action exemption applies in this case, and no further Commission activity is required under the federal statute."

  In an earlier February 2007 filing Commission Staff had urged the Commission to "determine that the prior state action exemption of EPAct 2005 does not apply to the Time-Based Metering and Communications Standard…."

Montana

Regulatory:

- In a December 2006 Order, the Montana Public Service Commission deferred a decision to adopt PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005. The Commission said it will consider whether to adopt the standard for each utility in each utility's next general rate case. The Commission closed the proceeding via the same Order.

Nebraska

No legislative or regulatory policy activity related to demand response was identified for this report.

Nevada

Regulatory:

- In January 2007, the Nevada Public Utilities Commission issued an Order closing a proceeding it opened in consideration of whether to adopt PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005. In the Order, the Commission stated the following:

  > "…time-based metering could allow customers to play a more meaningful role in managing their energy use and costs, the feasibility of using and/or requiring such in this State is still being undertaken. Before implementing additional regulations, the Commission will evaluate the research and cost/benefit analyses that are currently being performed by Sierra [Sierra Pacific Power Company] and NPC [Nevada Power Company]."

  Sierra Pacific and Nevada Power submitted their analyses in March 2007. In April 2007, the Commission directed the two companies to do further research.

New Hampshire

Regulatory:

- In January 2008, the New Hampshire Public Utilities Commission issued an Order in its proceeding to consider adopting PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005 in which it determined that it is "appropriate to implement" time-based metering standards. Though the Commission endorsed the idea of establishing time-based metering standards, it deferred the actual creation and implementation of them to future proceedings:

  > "[It is] Further Ordered, that the details, including cost-benefit analyses, form of rate design, time of implementation and applicable customer classes shall be determined in a separate proceeding or proceedings to be initiated by the Commission."

  The rationale for the deferral, according to the January 2008 Order, was that the "potential benefits of time-based rates deserve further inquiry in order to determine how best and on what schedule to implement the federal standard." Specifically, the Commission cited the need to resolve the question of which time-based rate is appropriate for each utility and customer class. It explained that it planned to deal with every utility separately and not to open a broad rulemaking proceeding. The Commission said it planned to consider—in each of the individual proceedings it opens—proposed pilot projects and the issue of cost-recovery for implementing time-based rates. In addition, the Commission noted its intent to form working groups to "facilitate cost-based planning."

  In September 2008, the Commission issued an "Order Concluding Investigation" in which it directed its Staff to create a working group to guide deployment of AMI and time-based rates:

  > "ORDERED, that Staff shall convene a meeting among the parties to this proceeding for the purpose of establishing a working group to facilitate the evaluation and implementation of advanced metering infrastructure and time-based rates in New Hampshire and that such working group make a report to the Commission by December 1, 2008 with regard to next steps toward utility specific cost-benefit analyses regarding such implementation and related matters…."

Legislative:

- In July 2008, Governor Lynch signed legislation, effective in September 2008, authorizing rate-recovery for utility investments in distributed energy resources (SB 451). The purpose of the law is to stimulate public-utility investment in distributed resources as they benefit the "transmission and distribution system under state regulatory oversight." The law defines "distributed energy resources" as to include demand response and "technologies or devices located on or inter-connected to the local electric distribution system for purposes including but not limited to reducing line losses, supporting voltage regulation, or peak load shaving."

  Key language of the new law includes:

  - "Notwithstanding any other provision of law to the contrary…a New Hampshire electric public utility may invest in or own distributed energy resources, located on or inter-connected to the local electric distribution system."
  - "Distributed electric generation owned by or receiving investments from an electric utility under this section shall be limited to a cumulative maximum in megawatts of 6 percent of the utility's total distribution peak load in megawatts."
  - "In addition, once the cumulative generation authorized under this chapter for a given public utility reaches 3 percent of the utility's total distribution peak load in megawatts, then that utility shall not be allowed to add any additional non-renewable generation under this chapter, until the cumulative renewable generation installed pursuant to this chapter, as a percentage of total generation installed pursuant to this chapter, shall equal or exceed twice the sum of the then- applicable percentage requirements for class I and class II under RSA 362-F:3."
  - "A New Hampshire electric public utility may seek rate recovery for its investments in distributed energy resources from the commission by making an appropriate rate filing."

  The law also establishes the exact requirements for how utilities may seek rate recovery for investments in distributed resources. Rural electric cooperatives that have a certificate of deregulation on file with the New Hampshire Public Utilities Commission, however, are exempt from these requirements. Furthermore, the law includes this exclusion: "Any renewable generating equipment funded in part by a distribution utility under this chapter shall not be included in the calculation of the total rated generating capacity…for purposes of limiting net energy metering." Finally, the law directs the Commission to report, by November 2010, to the governor and key state legislators about the "distributed energy resources investments proposed and implemented."

New Jersey

Regulatory:

- In November 2007, the New Jersey Demand Response Working Group (DRWG) filed its proposed demand response program with the New Jersey Board of Public Utilities. The DRWG recommended a pilot program that would procure 300 MW of demand response and would leverage existing PJM programs for the sake of expediency and cost-effectiveness. While the pilot would use the PJM Capacity Market business rules, and utilize its software infrastructure and personnel, the DRWG agreed that additional incentives—"premium payments"—should supplement existing PJM programs. The DRWG suggested that electric distribution companies (EDCs) should administer the premium payments. It also stated that the costs of the pilot program should be funded by the EDC's "Retail Margin collections." Furthermore, the DRWG informed the Board of Public Utilities that any demand response program should be offered statewide to all EDC distribution customers. Finally, the DRWG noted that in its second phase of operation it will focus on developing a competitive-procurement process for demand response.

In response to the DRWG's proposal, the New Jersey Department of the Public Advocate, Division of Rate Counsel filed comments in November 2007 in which it "strongly urges a competitive RFP process for future procurement programs."

The DRWG was formed in June 2007 per direction of the Board of Public Utilities—it was charged with developing a demand response procurement program that would enable the deployment of demand response by June 2008.

- In July 2008, the New Jersey Board of Public Utilities opened two proceedings that are intended to facilitate the development of demand response programs that would be effective beginning June 2009. One of the proceedings is to focus on working with EDCs to establish programs that would collectively yield 600 MW of demand response. The other will take a market-based approach—by considering proposals from "all energy industry entities, including but not limited to energy suppliers, curtailment service providers (CSPs) and utilities"—to deliver up to 600 MW of demand response. Proposals were filed in both proceedings in August 2008. In September 2008, the Board of Public Utilities issued an Order in which it requested that the market-based proposals filed in August 2008 be modified. It also solicited additional proposals. Modifications and additional proposals were due in October 2008.

  In September 2008, the Board of Public Utilities also asked its Staff to reconvene the New Jersey DRWG to evaluate the proposed programs filed in August 2008 and October 2008. As part of the evaluation process, the DRWG was to consider how to modify the proposal it presented to the Board of Public Utilities in November 2007 and how to include it in plans for implementing demand response programs by June 2009. In late September 2008, the DRWG completed its evaluation and proposed that the state's four EDCs administer demand response under the direction of the Board of Public Utilities. A sketch of this proposal is found in the following passages from it:

  - "If approved by the Board, this program will provide a supplemental financial incentive ('Premium Payment') to the existing market values currently offered in the PJM capacity program to participants who deliver eligible demand response that has been measured and verified by PJM…."
  - Each EDC's share of the budget will be determined by its percentage share of New Jersey's total non-residential electric load minus any existing non-residential demand response in that EDCs service territory, multiplied by the 600 MW goal ('EDC Cap')."
  - "The Modified Proposal uses the existing PJM Capacity Market Business Rules, PJM procedures, software infrastructure and personnel. PJM will assist with the implementation of the Modified Proposal in a variety of ways, including, among others, by (i) determining whether facility resources qualify for the DR pilot; (ii) registering and tracking resources participating in the DR Pilot; (iii) notifying the EDCs when particular facilities have requested enrollment as a DR Pilot resources; (iv) initiating emergency and load management events; (v) tracking performance of DR resources; and (vi) providing performance reports and support data for each event to each EDC and the Board that will be used to substantiate whether particular DR resources have earned the DR pilot premium payment…."
  - "The Modified Proposal recommends that Premium Payments for this program be administered by the EDCs."

- In April 2008, Governor Corzine released the Draft New Jersey Energy Master Plan. The Draft Energy Master Plan is the state's proposed "framework for a long-term energy strategy" through 2020. It identifies four challenges the state faces and finds that "by far, the most cost-effective way to preserve our reliability and reduce capacity costs is to reduce peak demand." Furthermore, reducing peak demand is one of the plan's five overarching goals. More specifically, the draft plan aims to decrease peak demand by 5,700 MW by 2020 by doing the following:

- Expand real-time pricing for commercial and industrial customers with a peak demand of at most 600 kW or greater by 2010 and at most 500 kW or greater by 2012.
- Expand incentives for participation in regional demand response programs.
- Evaluate a strong "inverted tariff" pricing system for residential customers.
- Move the state's electricity grid toward the development of a "smart grid" infrastructure.
- Monitor the results of all demand response initiatives through 2011 and implement the most effective mix of action steps to achieve a total peak demand reduction of 5,700 MW by 2020.

To facilitate the adoption of the Energy Master Plan, the New Jersey Board of Public Utilities held a series of public hearings in July 2008 and has solicited comments about it. Previously, in June 2008, it held a series of panel discussions about topics the Energy Master Plan addresses. The Board of Public Utilities also solicited comments, which were due in July 2008.

- Via a January 2008 Order, the New Jersey Board of Public Utilities approved the 2008 Basic Generation Service procurement plans filed by Atlantic City Electric, Jersey Central Power & Light, Public Service Electric & Gas, and Rockland Electric. The utilities' BGS procurement plans include an "hourly energy pricing service" for customers with a peak load share of 1000 kW or higher, which is called "Basic Generation Service—Commercial and Industrial Energy Pricing."

New Mexico

Regulatory:

- In January 2008, the New Mexico Public Regulation Commission opened a proceeding to investigate what effect incentives will have to motivate utilities to deploy energy efficiency and load management. In May 2008, the Commission held a "pre-workshop conference."
- In September 2006, the Commission opened a proceeding to consider whether to adopt PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005. The Commission has held several workshops as part of the proceeding and asked New Mexico utilities to file white papers on AMI and time-based rates. The utilities filed these white papers in December 2006 and January 2007, and presented them in January 2007 at the Commission's Advanced Metering Utility Workshop. No subsequent activity in the proceeding was identified for this report.

Legislative:

- In February 2008, Governor Richardson signed legislation that directs utilities to include load management and energy efficiency programs in their resource portfolio (HB 305). It also sets a minimum threshold for action:
  - By 2014, save 5% of total 2005 retail kWh sales
  - By 2020, save 10% of total 2005 retail kWh sales

  The new law defines load management as demand response and it distinguishes in its provisions between load management and energy efficiency. Furthermore, the new law mandates public utilities to file every three years with the New Mexico Public Regulation Commission a "comprehensive measurement, verification and program evaluation report" that evaluates energy and demand savings, cost-effectiveness of programs, and how well public utilities implement programs.

New York

Regulatory:

- In July 2007, the New York Public Service Commission decided not to adopt PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005. The Commission determined that it already provides a "time-based metering and communications standard comparable to PURPA." It found that although it has not adopted time-based rates for all of its customer classes, it has implemented both mandated and voluntary dynamic rates for various customer classes. The Order states "mandatory time-of-use rates are in effect for the utilities' largest customer classifications [and]…. optional time-of-use rates are available to all residential customers." In the Commission's interpretation, this passes the comparability test:

  > "We interpret the comparable standard to include time-based metering and communications devices that are made available to some, but not all, electric customer classes. This interpretation recognizes that the comparable standard is an alternative means of complying with the full time-based metering and communications standard under PURPA."

  The Commission also references its AMI Initiative (whereby utilities have been required to file AMI plans), noting that it is working to deploy advanced metering—to the extent feasible and cost effective—to customers who currently are not offered time-based rates.

  The July 2007 Order ended the Commission's consideration of EPACT 1252.

- Since August 2006, the Commission has had a proceeding to consider deploying AMI. The proceeding began when the Commission directed utilities, in response to EPACT 1252, to investigate the possibility of deploying smart metering and AMI. Furthermore, the Commission directed utilities to file AMI plans by February 2007. In October 2007, the Commission solicited comments about the plans. In April 2008, the Commission's Staff held a technical conference. No subsequent activity in the proceeding was identified for this report.

- In June 2008, the Commission issued an Order adopting an Energy Efficiency Portfolio Standard (EEPS). The EEPS mandates reducing usage by 15% of projected levels by 2015. In the same Order, the Commission directed utilities to do several things:

  - Collect annually $172 million, via a System Benefits Charge, for the purpose of funding efforts to realize the EEPS
  - File with the Commission within 90 days, plans for implementing energy efficiency programs
  - File, on an annual basis, status reports on efforts to meet the EEPS

  The EEPS proceeding, however, remains open as the Commission continues to consider "issues of program design," which include the role of demand response in the EEPS. To that end, in July 2008, the proceeding's ALJs issued a Ruling in which they set the procedural schedule for designing and implementing the EEPS. The ALJs established the schedule so that it would be possible to "bring the remaining EEPS design issues before the Commission in three groupings: first, policy concerning utility incentives; second, all critical path EEPS design issues; and third, outstanding policy issues."

  The July 2008 Ruling also created five working groups, which are to carry the load of the procedural schedule. The groups are to provide draft recommendations by October 2008. The five new working groups are:

  - Working Group V: Natural Gas
  - Working Group VI: On-bill Financing

- Working Group VII: Workforce Training and Development
- Working Group VIII: Demand Response and Peak Reduction
- Working Group IX: Efficiency Potential

The July 2008 Ruling also identified several "critical path" issues, including:

> **Demand Response and Distributed Generation**
>
> Defining the role of demand response and distributed generation in this proceeding is a critical path issue because gains can be made in reducing peak load in constrained areas, while at the same time realizing significant energy savings. The EEPS Order includes consideration of demand effects, in particular in constrained areas, in the criteria for program approval. The principal issue for working group discussion and recommendations is to identify specific measures that are not presently achievable through ISO and SBC programs, utility programs, or EEPS initiatives as recently ordered by the Commission. In addition, the environmental justice roundtable requested consideration of a study to assess health impacts on communities that host peak generation facilities to a disparate extent, and of opportunities to render those facilities obsolete through the acquisition of energy efficiency resources. We will immediately convene a working group on these issues."

In April 2008, the Commission Staff made two filings that support the goal of including demand response in the EEPS effort. Of these filings, the "Preliminary Proposal or Energy Efficiency Program Design and Delivery" is the most explicit, as seen in these excerpts from it:

- Listed under "General Principle #4"

  "Getting energy price signals better aligned with the costs of providing services is a critical part of effectively developing energy efficiency as a resource."

  "Advanced metering and commensurate implementation of more cost-causal, time-differentiated delivery and energy service rates and rate structures should be encouraged. End-use retail rates and rate structures should more accurately reflect the manner in which various costs (i.e., supply, transmission, and distribution) are incurred by utilities in responding to customer demands for service, and, conversely, should more accurately reflect the costs avoided by utilities when customers exercise strategic discretion in the timing and volume of their use of services. Implementation of more sophisticated time-differentiated (TOU) rate designs, especially hourly load-integrated pricing rate options, not only provide customers with stronger and more meaningful price signals to consider in developing rational strategic (managed) energy-use responses, they also reduce the need to consider institution of supplemental incentives (or subsidies) that otherwise might be required to encourage end-use customers' participation in the programs."

- Listed in Appendix 2, "Activities with the Potential for Significant Energy Efficiency Savings in the Long Term"
  - Allow additional opportunities for small customer aggregation to participate in demand response markets.
  - Expand time-sensitive pricing to additional customers.
  - Offer a voluntary TOU rate for all customer classes, everywhere in the state.
  - Redesign residential voluntary TOU rates to make them more attractive to customers.

- ❖ Examine potential applications for a smart grid using meters that enable two-way communication.
- ❖ Consider a critical-peak pricing program for residential and small C&I customers, such as California is now implementing.
- ❖ Install upgraded meters that can capture better data on how electricity is used and that can provide two-way communication to allow for control of appliances, lighting, air conditioning, etc.
- ❖ Encourage use of automated demand response programs.
- ❖ Design metering and communication protocols to support efficiency and load management program evaluation. Advanced metering offers the opportunity to better determine the load shape impacts of efficiency measures, which is important in documenting the capacity benefits from efficiency programs.

In February 2008, however, the proceeding's ALJs issued a Straw Proposal in which they write:

> "At this time, we do not propose specific demand reduction programs for inclusion in the EEPS. Integration of demand reduction into the EEPS should continue to be explored."
>
> "It should be noted that any decision regarding demand response in this proceeding will not preempt the field. Utilities and other entities may propose demand response programs independent of the EEPS."

The Commission has been considering an EEPS since May 2007, when it opened this proceeding. At the time, it noted that it would consider energy efficiency efforts to include "demand response technology and utility rate incentives [that]… encourage customers to shift usage and reduce peak loads."

- In April 2008, Governor Patterson announced the initiation of a new State Energy Plan—the first since 2003. Governor Patterson also created the State Energy Planning Board, which is in charge of the process of developing the plan. In May 2008, the State Energy Planning Board released two documents that will guide the development of the Energy Plan: (1) "Draft Scope of the 2009 New York State Energy Plan and Public Solicitation of Comments" and (2) "Framework for Implementing the Work of the NYS Energy Planning Board." The final State Energy Plan is expected to be complete by June 2009.

North Carolina

Regulatory:

- In August 2007, the North Carolina Utilities Commission decided not to adopt PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005. The Commission stated that it did not adopt the PURPA standard because it agreed with testimony submitted in the course of the proceeding that provided examples that "…the Commission and the utilities have been actively promoting time-based rates for at least the last three decades." Both Progress Energy and Duke Energy, for example, "already offer a variety of programs essentially identical to all but one of those suggested by" EPACT 1252. Furthermore, in February 2007 the Commission's Staff also recommended declining adoption of EPACT 1252.
- In March 2008, the Commission issued an Order that effectively terminated the fixed-payment programs of Duke Energy and Progress Energy. The Commission determined in the proceeding that the utilities' fixed-payment programs encouraged consumers to increase their energy use. The

Commission's Staff found that these programs lead to increased energy use and that customers on the flat rate contributed more to peak demand than customers not on the rate. The Commission, however, established a grandfather clause, allowing customers already on the flat rates, or who applied to participate in the programs, to remain on them. Duke Energy and Progress Energy are to file a report with the Commission within six months to outline their efforts to increase energy efficiency and conservation. (Both Duke Energy and Progress Energy have filed, since February 2008, monthly status reports on their efforts to comply with the Commission's Order.)

- In October 2006, the Commission opened a proceeding to consider DSM programs. In December 2007, the Commission issued an Order closing the proceeding as it expects that the implementation of Senate Bill 3 (SESSION LAW 2007-397), which was passed in August 2007, will address most of the issues raised in the proceeding. (The Commission, for example, has opened a new proceeding to assist in the implementation of the law.) The Commission initially intended this proceeding to be "an open forum to parties that wanted a generic investigation into energy efficiency and DSM programs." When the General Assembly began considering Senate Bill 3, however, the proceeding became "a generic forum for fact finding and as a complement to the General Assembly's activities."
- In February 2008, the Commission adopted Final Rules in its proceeding to implement legislation that created a Renewable Energy and Energy Efficiency Portfolio Standard (REPS) that considers demand response to be an eligible activity for cooperative and municipal utilities to meet the REPS. (Public utilities may not use demand response to meet the REPS.) By adopting the Final Rules, the Commission thereby implemented the law—Senate Bill 3/ Session Law 2007-397—which Governor Easley signed in August 2007. In its Final Rules, the Commission directs each utility to file with the Commission by September 2008 its first annual REPS compliance plan. (Utilities that are required to file integrated resource plans are to file their REPS compliance plan as part of them.) Beginning in 2009, each utility is also to file an annual REPS compliance report.

  The Commission opened this proceeding in August 2007 in order to "adopt new rules and modify existing rules, as appropriate, to implement Session Law 2007-397." The legislation directed the Commission to analyze and report on whether rate structures, policies, and measures in effect in other states and countries—which promote a mix of generation involving renewable energy sources and demand reduction—should be implemented in North Carolina.

Legislative:

- In August 2007, Governor Easley signed legislation that creates a REPS that considers demand response to be an eligible activity for cooperative and municipal utilities to meet the REPS (Senate Bill 3/Session Law 2007-397). According to the legislation, however, "public utilities" may not use demand response to meet the REPS.

  The REPS for cooperatives and municipalities is:

  - 2012: 3% of 2011 North Carolina retail sales
  - 2015: 6% of 2014 North Carolina retail sales
  - 2018 and thereafter: 10% of 2017 North Carolina retail sales

  The REPS for public utilities is:

  - 2012: 3% of 2011 North Carolina retail sales
  - 2015: 6% of 2014 North Carolina retail sales
  - 2018: 10% of 2017 North Carolina retail sales
  - 2021 and thereafter: 12.5% of 2020 North Carolina retail sales

Furthermore, the legislation directs the North Carolina Utilities Commission to analyze and report on whether rate structures, policies, and measures in effect in other states and countries that promote a mix of generation involving renewable energy sources and demand reduction should be implemented in North Carolina. The Commissionfiled the report with the Governor and the General Assembly inSeptember 2008[RHS4].

North Dakota

Regulatory:

- In August 2007, the North Dakota Public Service Commission issued an Order announcing that it would initiate a rulemaking to pursue a "modified version" of PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005. Through this rulemaking, the Commission indicates it anticipates mandating utilities to do the following:
  - Offer time-based rate schedules—including TOU pricing, critical-peak pricing, real-time pricing, and credits for customers with pre-established load reduction programs—to large C&I customers
  - Provide each large C&I customer, who requests a time-based rate, with a "time-based meter capable of enabling the utility and the customer to offer and receive such rate"

  In the Order, the Commission also directed each jurisdictional utility to include in its annual report a progress report of its effort toward making smart metering available for all customers.

  No subsequent activity in the proceeding was identified for this report.

Ohio

Regulatory:

- In March 2007, the Public Utilities Commission of Ohio issued a Finding and Order that adopts the Staff's recommendations regarding PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005:

  > "Based on the record in this proceeding, we agree with staff that there may be some questions as to whether many of the EDU's current tariffs comply with the EPACT. Consequently, all EDUs should offer tariffs to all customer classes which are, at a minimum, differentiated according to on and off-peak wholesale periods. Time-of-use meters should be made available to customers subscribing to the on and off-peak tariffs. We also agree that staff should analyze the cost benefit of AMI deployment strategies. Consistent with staff's original proposal, the analysis should include system benefits that may accrue to the EDU, customer benefits, and societal benefits."

  The March 2007 Order, however, did not close the proceeding, but rather called for a "series of technical conferences to discuss further associated issues and cost sharing and recovery mechanisms (e.g., each EDU's detailed AMI business case analysis)." The Commission also directed electric distribution companies to file, in preparation for these conferences, a comprehensive list of AMI technologies and corresponding costs as well as a "copy of the sections of their tariffs which include daily time sensitive rates."

  In April and May 2007, various parties to the proceeding petitioned for a rehearing of the case. The Commission denied these requests in a May 2007 Order.

  Later in May 2007, the Commission opened a new proceeding to facilitate the smart metering workshops mandated by the Commission's March 2007 Order.

- In May 2007, the Commission opened an ancillary EPACT 1252 proceeding—one to facilitate technical workshops about smart metering. The impetus for hosting these workshops is the March 2007 Order in the main EPACT 1252 proceeding, which mandated a "series of technical conferences to discuss further associated issues and cost sharing and recovery mechanisms (e.g., each EDU's detailed AMI business case analysis)." The Commission held the sixth and final of these technical workshops in December 2007. At it, electric distribution utilities presented their cost-benefit analyses for deploying AMI. To complement the activity at the workshops, the Commission created an online "Smart Metering Discussion Group."
- In July 2008, the Commission opened a proceeding in response to Substitute Senate Bill 221, which Governor Strickland signed in May 2008. Specifically, the Commission began the proceeding to address its Staff's proposed rules for the process of utilities filing market-rate offers (MRO) and electric-security plans (ESP). In September 2008, the Commission issued an Order approving the Staff's proposed rules with modifications—several of these approved rules address time-differentiated pricing:
  - "The electric utility shall demonstrate [when filing an SSO application for an MRO] that an independent and reliable source of electricity pricing information for any product or service necessary for a winning bidder to fulfill the contractual obligations resulting from the competitive bidding process (CBP) is publicly available…. The published information shall be representative of prices and changes in prices in the electric utility's electricity market, and shall identify pricing of on-peak and off-peak energy products that represent contracts for delivery…."
  - "Prior to establishing an MRO…an electric utility shall file a plan for a CBP [competitive bidding process] with the commission…. Each CBP plan that is to be used to establish an MRO shall include the following:"
    - "Detailed descriptions of the customer load(s) to be served by the winning bidder(s)…. If customers will be served pursuant to time-differentiated or dynamic pricing, the descriptions shall include a summary of available data regarding the price elasticity of the load."
    - "The CBP plan shall include a discussion of time-differentiated pricing, dynamic retail pricing, and other alternative retail rate options that were considered in the development of the CBP plan."
    - "The CBP plan shall include a discussion of generation service procurement options that were considered in development of the CBP plan, including but not limited to, portfolio approaches, staggered procurement, forward procurement, electric utility participation in day-ahead and/or real-time balancing markets, and spot market purchases and sales."
    - "The electric utility shall show, as a part of its CBP plan, any relationship between the CBP plan and the electric utility's plans to comply with alternative energy portfolio requirements…and energy efficiency requirements and peak demand reduction requirements of…the Revised Code."
  - "If the CBP plan is approved by the commission…the electric utility shall file an annual report on its CBP."
    - "The annual report shall describe the operation to date of any time-differentiated and dynamic rate designs implemented under the CBP, the approaches used to communicate price and usage information to consumers, and observed price elasticity."
- In July 2008—and in accordance with Substitute Senate Bill 221, signed by Governor Strickland in May 2008—FirstEnergy Corp, Duke Energy Ohio, and AEP Ohio filed their Electric Security

Plan (ESP) with the Public Utilities Commission of Ohio. The Commission has opened a separate proceeding for each utility's ESP. Each utility's ESP includes provisions for demand response, smart metering, or the smart grid. Summaries of each proceeding and each utility's ESP are below.

FirstEnergy Corp
(Ohio Edison Company, the Cleveland Electric Illuminating Company, and the Toledo Edison Company)

- A technical conference was held in August 2008
- An evidentiary hearing and public hearings were held in October 2008
- Key passages from the ESP include:
  - "The Companies will conduct an AMI pilot program using advanced metering technology capable of displaying real time energy usage to approximately 500 individual residential customers"
  - "The purpose of the AMI pilot is to determine whether a program that combines Summer time-of-day generation rates with real time energy usage information can effectively change customer behavior and energy consumption"
  - "The Companies will offer Dynamic Peak Pricing for the program. Once participants in the study are selected"
  - The Companies will establish an AMI working group to complement the pilot program
  - "The Companies also commit to undertake and complete a comprehensive Smart Grid study on or before December 31, 2009"
  - "The Companies will commit to provide up to $5 million of investment each year from January 1, 2009 to December 31, 2013 for customer energy efficiency/demand side management improvements made on and after January 1, 2009."

Duke Energy Ohio

- Public hearings were held in October 2008
- Testimony of intervernors and the Commission's Staff was filed in October 2008
- Evidentiary hearings were scheduled for November 2008
- Key passages from the ESP include:
  - "The smart grid system will transform the Company's transmission and distribution system into an integrated, digital network, similar to a computer network, to produce operating efficiencies, enhanced customer and utility information and communications, innovative services and other benefits."
  - "Smart meters will provide real-time energy usage information and the smart grid system will enable consumers to manage their energy usage more closely. This system will provide a platform for innovative energy efficiency programs and time-of-use rates, which will increase conservation and shift energy demand away from peak usage periods."

AEP Ohio (Columbus Southern Power Company and Ohio Power Company)

- A technical conference was held in August 2008
- Public hearings were held in October 2008
- Evidentiary hearings were scheduled for November 2008

- Key passages from the ESP include:
    - "CSP is proposing to implement phase 1 of its gridSMART initiative. This initiative will improve the information provided to customers with which they can control their energy consumption through modern grid management. The net cost of this first phase of gridSMART is estimated to be $19.7 million of O&M and $89.2 million of capital investment."

Legislative:

- In May 2008, Governor Strickland signed Substitute Senate Bill 221 mandating a peak-load reduction standard:

  "Beginning in 2009, an electric distribution utility shall implement peak demand reduction programs designed to achieve a one per cent reduction in peak demand in 2009 and an additional seventy-five hundredths of one per cent reduction each year through 2018."

  The new law also sets standards for energy efficiency and renewable energy. In addition, it requires the Ohio Public Utilities Commission to report annually the verification of peak-demand reduction achieved by utilities complying with these standards. Finally, the law establishes that it is state policy to "encourage innovation and market access for…demand-side management, time-differentiated pricing, and implementation of advanced metering infrastructure."

Oklahoma

Regulatory:

- In October 2007, the Oklahoma Corporation Commission issued a Notice of Proposed Rulemaking to amend its current rules for electric utilities as set forth in Oklahoma Administrative Code. The Commission is proposing to add a subchapter to the Administrative Code entitled "Demand Programs," which would establish demand response and other DSM requirements for utilities. In January 2008 and then again in February 2008 the Commission issued further iterations of the propose rules. The Commission has received and posted comments about the proposed rules. It also has hosted several types of meetings to facilitate the process of adopting them:
    - Technical conferences were held in November 2007, December 2007, January 2008, and February 2008
    - A public hearing was held in December 2007
    - En Banc hearings were held in February 2008 and March 2008
    - A "Demand Program Collaborative" (also known as the "Rulemaking Collaborative") met in April, May, une, July, and August 2008

  In September 2008, the Commission issued a revised set of proposed rules in response to stakeholder input about them. Stipulations of the revised rules include:
    - "All electric utilities under rate regulation of the Commission shall propose, at least once every five years, and be responsible for the administration and implementation of, a demand portfolio of energy efficiency and demand response programs within their service territories. Such proposals shall be made by filing an application with the Commission on or before July 1 prior to the year the programs will be effective."
    - The application shall contain "a base line describing the state of the market that each program is intended to address, taking into account applicable building energy codes and appliance and equipment energy standards."

- The application shall contain "a description of the barriers to investment in energy efficiency and demand response in the absence of each program and the ways each program will reduce or eliminate these barriers."
- The application shall contain "a plan for evaluation, measurement, and verification of performance and results of the demand portfolio and each program, including a plan for the use of deemed savings, if applicable, or the use of statistical sampling, if applicable, or the use of metering, where appropriate."
- The applications may "integrate energy efficiency and demand response."
- "Each utility shall report by June 1 of each year on the performance of energy efficiency and demand response programs for the preceding program year and cumulative program performance."

The proposed rules, furthermore, would allow the Commission to set specific goals for each utility to reduce peak demand, electricity consumption, and capacity addition.

Oregon

Regulatory:

- In May 2008, the Oregon Public Utility Commission approved Portland General Electric's (PGE) plan to deploy over 850,000 smart meters, with deployment being completed by 2010. PGE has indicated that it expects to use the smart meters, which will be fully deployed by 2010, to facilitate future demand response and direct-load-control programs. It also anticipates creating a web portal through which customers using the smart meters can access information about their daily energy consumption. PGE reports that the smart meter deployment will cost $130–135 million, but that by 2011 it will yield annual operating savings of $18 million.

Pennsylvania

Regulatory:

- In September 2006, the Pennsylvania Public Utility Commission opened a proceeding in which it reconvened its Demand-Side Response Working Group, which had been created initially in 2001 but had been dormant since 2004. The Commission tasked the reconvened Demand-Side Response Working Group, which has a subgroup focused on smart metering, to help investigate the issues addressed in the September 2006 Order initiating the proceeding. Namely, these issues are:
  - "Energy utilities' current efforts to assist their customers to reduce usage, increase energy efficiency, and implement demand side response programs (including implementation of time-based rates), and whether additional cost effective and reasonable steps can be taken to increase those efforts materially (and, if so, the nature of those activities and the costs that the utility or other entity and customers would incur to implement them)."
  - "Whether Advanced Metering Infrastructure should be developed by Pennsylvania utilities, and, if so, the timeline and standards that should be established for the implementation of these systems for the various customer classes and the methods of sharing this information with customers, competitive energy suppliers, and other customer representatives."

  The Demand-Side Response Working Group filed, in June 2007, its report summarizing its activities. In the report, the group said that demand response directly and indirectly benefits ratepayers.

  In November 2008, the Commission will hold an en banc hearing to "to seek information from experts" about alternative energy resources as well as energy conservation, energy efficiency, and demand response. The Commission scheduled the hearing in attempt to gather additional information before acting on the Demand Side Working Group's recommendations. The hearing will focus on the answers submitted in response to a list of questions the Commission has posed.

- In May 2007, the Commission issued the Final Order in its electricity-price-mitigation case, in which it approved the creation of a consumer-education campaign (at a "potential" cost of $5 million) for "demand side response," energy efficiency, conservation, and low-income programs. It also directs the Commission's Office of Communication to convene a series of stakeholders meetings to help develop the campaign. The Final Order endorses demand response as one of the components of the plan but defers to the Pennsylvania Demand-Side Response Working Group to develop policy specifics.
- In 2006, the Commission established a proceeding to implement the Alternative Energy Portfolio Standards Act of 2004, but never issued a final ruling in it because the General Assembly began considering amendments to the law. In September 2007, after these amendments were ratified—in Act 35 of 2007—and the Commission was obligated to solicit comments and craft final standards, the Commission reopened the public comment period in the proceeding. While comments were due by October 2007, none were found posted on the Commission's website while developing this report. Furthermore, no subsequent activity in the proceeding was identified for this report.
- In compliance with the Alternative Energy Portfolio Standards (AEPS) Act of 2004, the Commission published in May 2008 its "2007 Annual Report of the Alternative Energy Portfolio Standards (AEPS) Act of 2004." (The legislation was notable at the time for inclusion of energy efficiency and demand response as alternative means of compliance with the standards.) The Commission's report indicates some energy efficiency and demand response activity relative to compliance.
- In June 2008, Governor Rendell announced that he had directed the Secretary of the Department of General Services to "implement across-the-board energy conservation measures," including demand response and smart metering. Specifically, the state will do the following:

  > "Reduce Energy Use During Peak Periods. The state will begin to review and implement smart meter and load shedding strategies in state-owned buildings to monitor a building's energy use throughout the day and automatically turning off certain items, such as central air, lamps or hot water heaters that draw energy during peak use times. This measure will set the foundation for effective load management for the future."

Legislative:

- In February 2008, the Pennsylvania House of Representatives passed a bill that would mandate deployment of smart meters and demand response, set peak-demand reduction goals, and establish M&V standards (HB 2200). Specifically, the House Bill included the following provisions:
  - ➢ The Pennsylvania Public Utility Commission would be required to develop a demand response and energy efficiency program which would administer the deployment of demand response by third parties.
  - ➢ Electric distribution companies would be required to file a smart meter deployment plan that would provide smart meters to all customers within ten years.
  - ➢ Default service providers would be required to file with the Commission by January 2010 "one or more" proposed TOU and real-time pricing plans applicable to all residential and commercial customers.

  In October 2008, the Senate passed its version of the bill. Later in October 2008, Governor Rendell signed HB 2200 into law, thereby creating Act 129. While the new law does have demand response and smart metering provisions, they are different than those in the bill the originally passed by the House. The new law's provisions are:

Demand Response

- "By January 1, 2010, or at the end of the applicable generation rate cap period, whichever is later, a default service provider shall submit to the [Pennsylvania Public Utility] Commission one or more proposed time-of-use rates and real-time price plans. The Commission shall approve or modify the time-of-use rates and real-time price plan within six months of submittal. The default service provider shall offer the time-of-use rates and real-time price plan to all customers that have been provided with smart meter technology under paragraph (2) (III). Residential or commercial customers may elect to participate in time-of-use rates or real-time pricing. The default service provider shall submit an annual report to the price programs and the efficacy of the programs in affecting energy demand and consumption and the effect on wholesale market prices."

Smart Metering

- "Within nine months after the effective date of this paragraph, electric distribution companies shall file a smart meter technology procurement and installation plan with the Commission for approval."
- "Electric distribution companies shall furnish smart meter technology as follows:
    - Upon request from a customer that agrees to pay the cost of the smart meter at the time of the request.
    - In new building construction.
    - In accordance with a depreciation schedule not to exceed 15 years."
- "Electric distribution companies shall, with customer consent, make available direct meter access and electronic access to customer meter data to third parties, including electric generation suppliers and providers of conservation and load management services."
- "An electric distribution company may recover reasonable and prudent costs of providing smart meter technology…as determined by the Commission."

The new law also directs the Commission to require electric distribution companies to adopt and implement by January 2009 "cost-effective energy efficiency and conservation plans" that reduce peak demand according to this schedule:

- By May 2013: 4.5% reduction of the 100 highest hours of annual system peak demand (as measured against peak demand from June 2007 through May 2008).
- By November 2013: "The Commission shall set additional incremental requirements for reduction in peak demand for the 100 hours of greatest demand" if it determines that the electric distribution companies' efficiency and conservation programs are cost effective.

- In July 2007, Governor Rendell signed into law Act 35 of 2007, which amends provisions of the state's Alternative Energy Portfolio Standards Act of 2004 so they include M&V standards for load management. Specifically, Act 35 directs the Pennsylvania Public Utility Commission to establish regulations affecting DSM deployment:

    "The commission shall within 120 days of the effective date of this act develop a depreciation schedule for alternative energy credits created through demand-side management, energy efficiency and load management technologies and shall develop standards for tracking and verifying savings from energy efficiency, load management and demand-side management measures. The commission shall allow for a 60-day public comment period and shall issue final standards within 30 days of the close of the public comment period."

In 2006, the Commission established a proceeding to implement the Alternative Energy Portfolio Standards Act of 2004, but never issued a final ruling in it because the General Assembly began considering amendments to the law. After these amendments were ratified—in Act 35 of 2007—and the Commission was obligated to solicit comments and craft final standards, the Commission reopened the public comment period in the aforementioned proceeding.

- In October 2007, legislation was introduced in the Pennsylvania Senate that would require utilities to develop and deploy demand response programs (SB 1134). (The legislative language cites mitigating environmental impacts as being one of the benefits of demand response.) The legislation also would establish a peak-demand reduction standard of 3% relative to the top 100 hours of peak demand between June 2007 and May 2008. Finally, the bill would direct utilities to file a demand response plan with the Pennsylvania Public Utility Commission by December 2008 and to file one every five years thereafter. The bill was amended in June 2008. No subsequent activity regarding the legislation was identified for this report.

- In November 2007, legislation was introduced in the Pennsylvania House of Representatives that would mandate utilities to "furnish" 40% of their customers with smart meters within three years of the legislation passing; 80% with smart meters within six years; and 100% with smart meters within nine years (HB 2017). Utilities would have to file their proposed smart metering plan to the Pennsylvania Public Utility Commission within six months of the bill becoming law. By 2010, default service providers would have to submit proposed TOU and real-time rate plans to the Commission, which, in turn, would have to approve or modify the plans within six months. Customer participation in these plans would be voluntary. No subsequent activity regarding the legislation was identified for this report.

Rhode Island

Regulatory:

- In July 2006, the Rhode Island Public Utilities Commission opened a proceeding to consider adoption of PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005 and to investigate how the standard relates to the state's omnibus energy act, the Comprehensive Energy Conservation, Efficiency and Affordability Act of 2006. In accordance with the law, in February 2008, the Rhode Island Distributed Generation Working Group filed with the Rhode Island General Assembly a report reviewing various demand response programs in New England. (The Comprehensive Energy Conservation, Efficiency and Affordability Act of 2006 directed the Commissioner of Energy Resources to "facilitate a stakeholder-led study of issues and barriers pertaining to implementation of distributed generation" and to report the findings of the study to the General Assembly by February 2007.)

  The Rhode Island Attorney General filed comments in January of 2007. These comments reflect skepticism that time-based rates and smart metering will make electricity markets more efficient and benefit customers. These comments conclude:

  > "Looking ahead, it would be my recommendation for the Commission that time-varying rates be considered carefully, and applied, if at all, in a fashion that maximizes the benefits and minimizes the likely problems."

  No subsequent activity in this proceeding was identified for this report.

- In July 2008, the State of Rhode Island contracted a demand response service provider to "enable and manage demand response capacity" in government buildings. Under the terms of the five-year contract, individual government buildings—including those at the town and city levels—may enroll in the service provider's demand response program.

Legislative:

- In June 2006, the Governor Carcieri signed the Comprehensive Energy Conservation, Efficiency and Affordability Act of 2006 (HB 8025 Substitute A). The new law includes several provisions that foster demand response:
  - Creates the Rhode Island Energy Efficiency and Resources Management Council—which is to advise the Office of Energy Resources about demand response among other things—and directs it to prepare by July 2009 a "reliability and efficiency procurement opportunity report" that is to address demand response.
  - Directs the Rhode Island Public Utilities Commission to establish by June 2008 standards for system reliability and for "energy efficiency and conservation procurement," which shall include standards and guidelines for demand response.
  - Directs each electrical distribution company to file triennially with the Commission a plan for system reliability and for "energy efficiency and conservation procurement" that addresses demand response.

South Carolina

Regulatory:

- In August 2007, the South Carolina Public Service Commission decided not to adopt PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005. In its August 2007 Order, the Commission stated that all regulated utilities within the state already offer time-based rates. In the same Order, however, the Commission found that there is a "conspicuous lack of focus" on residential and commercial smart metering, which may be due to a lack of awareness of the "availability and capability" of smart meters. As a result, it directed utilities to continue to make smart meters available to all customers and to propose within 180 days a campaign to educate consumers about smart metering. In February 2008, South Carolina Electric & Gas Company, Duke Energy Carolinas, and Progress Energy Carolina complied with the August 2007 Order and filed their "communication plans." No subsequent activity in the proceeding was identified for this report.

South Dakota

Regulatory:

- In July 2007, the South Dakota Public Utilities Commission decided not to adopt PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005. The Commission's decision is summarized in two passages from its July 2007 Decision:
  - "The Commission finds that little evidence was presented that demonstrated that the adoption of this standard at this time would meet the PURPA goals of energy conservation, efficiency of facilities and resources and equitable consumer rates. The Commission finds that adoption of the standard could result in the utilities being required to offer uneconomic programs that result in higher rates."
  - "At this time, the Commission is not convinced that the benefits of mandatory time-based metering for all customer classes will outweigh the costs."

  The Commission also stated in its Order that:

  > "The Commission recognizes that time-based metering programs can be beneficial…. However, the Commission believes that additional studies are needed as to the benefits of such programs for all customer classes in South Dakota."

Tennessee

Regulatory:

- To consider adoption of PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005, the Tennessee Regulatory Authority held separate proceedings for Entergy Arkansas, Kentucky Utilities, Appalachian Power, and Kingsport Power. Ultimately, in each of the proceedings the Tennessee Regulatory Authority decided not to adopt PURPA Standard 14:
  - Entergy Arkansas: In January 2007, the Tennessee Regulatory Authority determined that Entergy Arkansas's rates and services already met the standard set by EPACT 1252 so there was no need to adopt it.
  - Kentucky Utilities Company: In January 2007, the Tennessee Regulatory Authority determined that Kentucky Utilities Company's rates and services already met the standard set by EPACT 1252 so there was no need to adopt it.
  - Appalachian Power: In August 2006, the Tennessee Regulatory Authority determined that Appalachian Power's rates and services already met the standard set by EPACT 1252 so there was no need to adopt it.
  - Kingsport Power: In August 2006, the Tennessee Regulatory Authority determined that Kingsport Power's rates and services already met the standard set by EPACT 1252 so there was no need to adopt it.

Texas

Regulatory:

- In May 2007, the Public Utility Commission of Texas adopted rules for smart metering. The rules address a cost recovery surcharge; deployment planning; waiver provisions for advanced metering systems (AMS) that do not meet minimum functionality requirements; minimum functionality requirements; and whether AMS constitutes competitive energy service.
- In 2007, the Commission considered the development of a "designated form for quantifying a proposed surcharge for recovery of costs of deploying advanced meters." Through the proceeding, the Commission had hoped to also set guidance for how to identify the "costs and benefits of replacing existing meters at which electric transmission and distribution utilities deliver retail service with meters that have increased capabilities such as transmitting data to remote locations or providing data at short intervals"—otherwise known as smart meters. In March 2007, the Commission Staff solicited comments via the Texas Register. By June 2007, the Staff was to file its recommendation, and the Commission was supposed to decide whether to adopt the proposed form. Neither the Staff's recommendation nor the Commission's decision was found in the process of developing this report. Furthermore, no subsequent activity in the proceeding was identified for this report. The proceeding is now closed.
- In 2007, the Commission began considering changes in retail and wholesale markets due to smart metering. The Commission divided the work of this proceeding between six projects: (1) Interim Project; (2) Web Portal Project; (3) ERCOT Settlement Project; (4) Home Area Network Project (HAN); (5) Retail Market Interface Project; and (6) Customer Education Project. In April 2008, the Commission Staff filed a memo summarizing the progress of the proceeding and the proceeding's working group, called the Advanced Metering Implementation Team (AMIT). At the time of the memo, the AMIT was "finalizing the initial draft of requirements for the Transmission and Distribution Utility (TDU) web portal(s)," which are to provide at least "hourly data on a day-after basis" and possibly fifteen-minute data. The AMIT also was working on ERCOT settlement

requirements. Furthermore, the April 2008 Staff memo reports that ERCOT has decided to "fund a study which would show the best way for ERCOT to change its systems to accommodate full settlement using 15-minute interval data from AMS, as meters are deployed." The Staff and ERCOT are developing an RFP for conducting this study.

- In September 2008, the Commission filed with the Texas Legislature, in compliance with a law enacted in 2005, its second report on AMI—"Report to the 81st Texas Legislature: A Report on Advanced Electric Metering as Required by House Bill 2129". The Commission concluded in its report that deploying AMI is a "critical component of the evolving Texas electric market," not least of which because it enables demand response.

  Key passages of the report summarize the Commission's position on AMI:

  - "AMI can help the electric market to mature, yield savings for utilities, and create efficiencies in market processes for retail electric providers (REPs) and ERCOT. Although AMI has a cost, that cost becomes less of an issue in an environment of rising electric prices and increased generation demand where the investment can be offset by a combination of operational savings realized by the utility and electric savings by retail customers."
  - "Demand response and advanced metering should play a crucial role in the state's energy portfolio, especially during times of higher energy prices…. The Commission believes that AMI should be ubiquitously deployed [to] give Texas retail electric customers an increased ability to control their electric use."

  The report includes the following recommendations:

  - "The Governor's Competiveness Council in its Texas State Energy Plan recommended that the Commission have the Authority to order utilities to deploy advanced meters. The legislature should clarify that the Commission has the authority to order utilities to deploy advanced meters, as rapidly as possible, with the appropriate cost recovery provided under the Commission's advanced metering rule."
  - "The legislature should clarify whether the 2005 legislation relating to advanced meters… applies to utilities outside of ERCOT."
  - "State policy should also ensure that all retail customers have the option to have their billing determined on actual interval data captured from the advanced meters, so they receive the full benefits of changes in consumption behavior."
  - "State policy should continue to recognize that the retail electric market will benefit from knowledgeable residential electric customers making informed purchasing decisions to meet their energy needs."

  The law with which the Commission complied by filing the AMI report—HB 2129—directs the Commission to file such a report to the legislature each even-numbered year. The report is to summarize "the efforts of utilities in Texas to deploy advanced metering systems and infrastructure, and to identify any barriers to the implementation of advanced metering, as well as any recommendations to address those barriers."

- In 2007, the Commission opened a proceeding to implement the Efficiency Portfolio Standard (EPS) set by legislation—HB 3693—that Governor Perry signed in June 2007. After a series of workshops, the Commission issued an Order in April 2008 that repealed two existing rules and adopted one new rule in effort to implement the EPS. The Order discusses at length how demand response relates to the rules enforcing the EPS.

- In May 2008, every investor-owned electric utility in Texas filed with the Commission their "2008 Energy Efficiency Plan and Report." In these reports, the utilities—per state law—listed the results of their efforts to reduce, during 2007, 10% of their "total annual growth in demand." The utilities also describe their plans to meet the state-mandated energy-savings goals for 2008 and 2009:

- 15% of the electric utility's annual growth in demand of residential and commercial customers by December 2008
- 20% of the electric utility's annual growth in demand of residential and commercial customers by December 2009

Each of the utilities reported meeting the mandated demand-reduction goal of 10%. Most of the utilities' filings also include reports of reducing peak demand during 2007 as well as plans for demand response to complement energy efficiency in meeting the mandated goal for 2008.

Legislative:

- In June 2007, Governor Perry signed legislation that set an Efficiency Portfolio Standard (EPS) and encourages utilities to deploy demand response (HB 3693). The EPS applies to residential and commercial customers and directs utilities to reduce their customers' consumption by the following schedule:

  - "10 percent of the electric utility's annual growth in demand of residential and commercial customers by December 31, 2007"
  - "15 percent of the electric utility's annual growth in demand of residential and commercial customers by December 31, 2008, provided that the electric utility's program expenditures for 2008 funding may not be greater than 75 percent above the utility's program budget for 2007 for residential and commercial customers, as included in the April 1, 2006, filing"
  - "20 percent of the electric utility's annual growth in demand of residential and commercial customers by December 31, 2009, provided that the electric utility's program expenditures for 2009 funding may not be greater than 150 percent above the utility's program budget for 2007 for residential and commercial customers, as included in the April 1, 2006, filing"

  Furthermore, the new law includes two passages intended to foster demand response:

  - "Each electric utility in the ERCOT region shall use its best efforts to encourage and facilitate the involvement of the region's retail electric providers in the delivery of efficiency programs and demand response programs under this section"
  - "…it is the intent of the legislature that net metering and advanced meter information networks be deployed as rapidly as possible to allow customers to better manage energy use and control costs, and to facilitate demand response initiatives."

  Finally, the law stipulates that by January 2008, the Public Utility Commission of Texas, in consultation with the State Energy Conservation Office, "annually for a period of five years shall compute and report to ERCOT the projected energy savings and demand impacts for each entity in the ERCOT region that administers…demand response programs…and any other relevant programs that are reasonably anticipated to reduce electricity energy or peak demand or that serve as substitutes for electric supply."

Utah

Regulatory:

- In February 2007, the Utah Public Service Commission decided not to adopt PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005. The Commission's Determination gave three reasons:
  - ➢ The standard is unnecessary because Rocky Mountain Power (PacifiCorp), the only PURPA-covered utility doing business in Utah over which the Commission has ratemaking authority, already offers, (1) TOU rates, which are mandatory for customers using more than 1 MW, (2) seasonal rates, and (3) a peak-load reduction program.
  - ➢ There is an absence of supporting analysis demonstrating a need for the standard.
  - ➢ The timeframe for consideration and implementation of the standard is unrealistic.

  Nonetheless, the Commission directed Rocky Mountain Power to file by June 2007 a "decision summary report" that included the following:
  - ➢ A description of the survey that Rocky Mountain Power did of other utilities' experiences with smart metering and AMI and the selection of applicable literature or studies on which it based its conclusion.
  - ➢ A review and comparison of the cost and benefit information from these reports as compared with that used in the company's evaluation.
  - ➢ The reasons supporting the company's conclusion that smart metering, as envisioned by the Standard, is not cost effective for its applicable circumstances.

  Rock Mountain Power filed this report in July 2007.
- In June 2007, the Utah Department of Environmental Quality launched for the seventh summer in a row an alert system that encourages consumers to conserve electricity during periods of peak demand. The system is called Power Forward.

Vermont

Regulatory:

- In February 2007, the Vermont Public Service Board decided not to adopt PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005. Instead, it will "consider the standard's applicability on a utility-specific basis in a future rate case or rate-design case, as appropriate." The Decision cited two determining factors:
  - ➢ "There are considerable differences among Vermont's distribution utilities with respect to the number and type of time-based rates they offer, as well as the utilities' implementation of smart-metering technologies."
  - ➢ "Each utility's circumstances should be taken into account when determining whether to require the utility to change its rate design or its metering system. Adopting the EPACT 2005 smart metering and time-based standard on a statewide basis at this time would not allow this case-specific consideration to take place. Therefore, the Board will consider the applicability of the EPACT 2005 smart metering and time-based standard on a case-by-case basis in a future rate case or rate-design case, as appropriate."
- In August 2008, Central Vermont Public Service (CVPS) and the Vermont Department of Public Service launched a collaborative smart-grid pilot program open to participation by any utility in the

state. The collaboration, according to the utility and the state agency, will establish "templates and standards for new meter and communications technology." It will also develop CVPS SmartPower, "a systematic program to analyze and install the latest in metering technology over several years." (As of now, CVPS SmartPower is expected to run through 2013.) CVPS and the Vermont Department of Public Service expect that ultimately CVPS SmartPower will yield expanded time-of-day rate programs and new real-time rate programs. The capital investment for CVPS SmartPower is estimated to be $40 million.

Legislative:

- In March 2008, Governor Douglas signed into law the Energy Efficiency and Affordability Act of 2008 (H 520). The new law is similar to EPACT 2005 in that it directs Vermont's Public Service Board to "investigate opportunities for Vermont electric utilities cost effectively to install advanced 'smart' metering equipment capable of sending two way signals and sufficient to support advanced time of use pricing during periods of critical peaks or hourly differentiated time of use pricing." After its investigation, the Board is to require each utility to file plans for deploying smart meters and TOU pricing, provided that the utility serves a territory where such a deployment is "appropriate and cost-effective."

Virginia

Regulatory:

- In July 2006, the Virginia State Corporation Commission decided not to adopt PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005. As noted in the declining Order, "The Commission is not convinced that adoption of this standard is, at this juncture, in the public interest." The Commission began its EPACT 1252 proceeding in February 2006.
- In September 2007, Governor Kaine released the "Virginia Energy Plan," which is to reduce the growth rate of consumption by 40% by 2017 and to reduce GHG emission by 30% by 2025. It considers demand response to be a strategy for efficiency and conservation.
- In December 2007 and in compliance with 2007 legislation (SB 1416), the Commission reported to the Governor and the General Assembly how to meet the legislation's goal of reducing electricity consumption by 10% (of 2006 levels) by 2022 through DSM, conservation, energy efficiency, and load management programs. The Commission's filing is based on its Staff's report, which, in turn, stems from the findings of the Working Group the Commission formed to consider the implementation of the legislation. The Working Group concluded with the single recommendation that utilities should provide the Commission with an "expansion plan" that weighs the "avoided costs" accrued from the "implementation of a demand-side efficiency program" such as demand response.

  Other findings of the Staff's report include:

  - The 10% reduction goal is achievable "by raising electricity prices and then allowing customers to react to those prices."
  - "Four of the five sub-groups [of the working group] acknowledged that while the legislation focuses on a reduced energy consumption goal, reducing peak demand is also an important consideration."
  - "The sub-groups generally agreed that to support the attainment of an energy savings goal, measurement and verification methods would be needed to measure the energy impacts of all programs."
  - "The group holds that new opportunities exist to capture the potential for reductions in peak demand resulting from recent policy enhancements within the PJM Interconnection,

advances in telecommunications allowing real-time communication, and improvements in the affordability and functionality of demand response technology."

- "[The "demand/peak reduction"] sub-group found that increased deployment of demand response in the Commonwealth could yield substantial customer financial benefits and electric reliability benefits."
- "…Staff believes that it is advisable for Virginia's electric utilities to develop a current integrated resource plan that considers supply and demand resources for the Commonwealth and to thus determine the value of avoided electrical supply costs."

Legislative:

- In May 2008, Governor Kaine signed legislation that renews the state's Commission on Electric Utility Restructuring while renaming it the Commission on Electric Utility Regulation (SB 596). The new law also tasks this Commission with educating retail electricity consumers about demand response. The law requires the Virginia State Corporation Commission to convene a working group to identify "consumer education needs" pertaining to demand response, DSM, efficiency, and conservation.
- In April 2007, Governor Kaine signed legislation that supports further deployment of load management (SB 1416). The new law says:

  > "That it is in the public interest, and is consistent with the energy policy goals…of the Code of Virginia, to promote cost-effective conservation of energy through fair and effective demand side management, conservation, energy efficiency, and load management programs, including consumer education."

  Furthermore, the law sets an energy efficiency portfolio standard (EPS) that includes load management as a viable resource to meet the standard. It also directs the Virginia State Corporation Commission to open a proceeding to implement the EPS. Here is the pertinent legislative language:

  > "The Commonwealth shall have a stated goal of reducing the consumption of electric energy by retail customers through the implementation of such programs by the year 2022 by an amount equal to ten percent of the amount of electric energy consumed by retail customers in 2006. The State Corporation Commission shall conduct a proceeding to (i) determine whether the ten percent electric energy consumption reduction goal can be achieved cost-effectively through the operation of such programs, and if not, determine the appropriate goal for the year 2022 relative to base year of 2006, (ii) identify the mix of programs that should be implemented in the Commonwealth to cost-effectively achieve the defined electric energy consumption reduction goal by 2022, including but not limited to demand side management, conservation, energy efficiency, load management, real-time pricing, and consumer education, (iii) develop a plan for the development and implementation of recommended programs, with incentives and alternative means of compliance to achieve such goals, (iv) determine the entity or entities that could most efficiently deploy and administer various elements of the plan, and (v) estimate the cost of attaining the energy consumption reduction goal.

  The Commission complied with the law and opened a proceeding. It filed its findings and recommendations with the Governor and General Assembly in December 2007.

Washington

Regulatory:

- In August 2007, the Washington Utilities and Transportation Commission decided not to adopt PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005. The Commission determined (1) that it is inappropriate to "require generally" utilities to deploy smart metering and time-based rates and (2) that its existing policy created in response to the 1980 PURPA standards is sufficient relative to EPACT 1252. The Commission, in its August 2007 Decision, also said that comments submitted through the course of its EPACT 1252 proceeding affirmed the existing policy's prudence. (This policy states that "time-of-day ratemaking is acceptable only if cost-justified," and all five parties who submitted comments offered evidence that TOU rates and metering are not cost effective.)

  The Decision indicated that the Commission plans to consider smart metering and time-based rates on a case-by-case basis—in each utility's rate case or in "other proceedings considering the varying circumstances of each utility and each utility's customer classes"—until it determines that uniform standards would be cost effective for all consumers. Furthermore, the Commission directed utilities to consider demand response and smart metering while forecasting loads and assessing resources.

Legislative:

- In February 2007, smart-grid legislation was introduced into Washington State Senate (SB 6112). If passed, the legislation would do the following:

  Require the Washington State Department of Community, Trade, and Economic Development (CTED) to adopt rules by December 2008 creating a "tax credit certification process for smart grid energy technologies that promise to significantly improve the reliability, efficiency, and environmental integrity of electrical transmission and distribution systems."

  - Provide tax exemptions for the purchase, installation, and use of smart meters.
  - Require the State Energy Office and the CTED to develop a plan to promote efficient use of electrical and transmission systems, which would include "proposals for creating and strengthening public and private partnerships to promote smart grid energy improvements… and enhancement of smart grid business development in Washington state."

  In January 2008, the Senate passed a resolution to reintroduce and retain "in present status" the bill. No subsequent activity regarding the legislation was identified for this report.

West Virginia

Regulatory:

- In December 2006, the Public Service Commission of West Virginia decided not to adopt PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005, stating that it instead had adopted the collective recommendations of the parties to the proceeding. The parties to the proceeding recommended—via their October 2006 "consensus statement"—that the Commission not adopt PURPA Standard 14 but that "smart metering should be available as an option for members of all tariff classes." The consensus statement included the following:

  > "The EPACT 2005 standards for smart metering found in section 1252 would not be adopted. However, electric utilities will explore making smart metering available as an option for all tariff classes in their next rate case, if the utility is not already providing this service. The utilities will address this issue in their applications in their next rate cases. The Parties agree that a cost benefit study is not immediately needed. However,

should future electric utility load growth begin to put undue pressure on utilities to increase rates, then the Commission may direct a utility or utilities to conduct such a study in a future rate case or general investigation."

Wisconsin

Regulatory:

- In February 2007, the Public Service Commission of Wisconsin released its biennial strategic energy assessment, "Strategic Energy Assessment—Energy 2012." The assessment describes demand response as a tool to provide rate stability to energy customers.
- In July 2008, Governor Doyle's Task Force on Global Warming announced that it had finalized its report on how Wisconsin should address global warming. The Task Force on Global Warming recommended a set of GHG-reduction targets: to 2005 levels by 2014; to 1990 levels by 2022; and to a 75% reduction from 2005 levels by 2050. Furthermore, the group's report outlines more than "50 viable and actionable policy recommendations" to help meet the GHG-reduction targets.

  An interim report issued in February 2008 included recommendations relative to demand response:

  Aligning Public and Private Interests for Energy Conservation and Efficiency

  "In order to meet the conservation and efficiency goals set forth above in Recommendation 1, the Task Force recommends that the PSCW investigate and adopt innovative utility ratemaking approaches that promote conservation and efficiency programs by removing the disincentives that exist under current ratemaking policies for utilities to implement their own programs and support statewide programs, and provide in their place positive incentives for utilities to aggressively pursue conservation and efficiency opportunities. The objective of these changes should be to provide long-term customer benefits and maintain a healthy economy."

  Improved and Innovative Rate Design

  "This policy recommends that, in addition to altering the current ratemaking paradigm which incents construction of new plant over measures to reduce load, the PSCW investigate and adopt innovative rate designs that provide more accurate price signals to customers to incent reductions of GHG emissions associated with their energy consumption."

  Demand Response and Load Management

  "This policy recommends the development and implementation of a number of programs by the PSCW that will encourage and enable customers to reduce their contributions to utility peak demand and thereby lessen GHG emissions and the need for new energy infrastructure and to respond to signals in ways that will help shape utility load resulting in a more efficient electric system."

Wyoming

Regulatory:

- In January 2007, the Wyoming Public Service Commission decided not to adopt PURPA Standard 14 ("Time-Based Metering and Communications") as enacted in EPACT 2005. In the January 2007 Order the Commission concludes:

  > "The Commission finds the comments provided by the parties to this proceeding indicated there was no support for this section. The Commission finds adoption of this section is not a real opportunity for Wyoming ratepayers because the economic and social makeup of the state does not make smart metering a useful tool. However, the Commission finds there is support from the commenters [sic] to hold a technical conference on the subject of smart metering. Additionally, the Commission finds adoption of Section 328(D), regarding third-party marketers' ability to sell electric energy to retail customers, would be illegal in Wyoming. Section 328(D) is inconsistent with state law, and 16 U.S.C. § 2623(a)(1) requires the PURPA standards, if adopted, to be consistent with state law. The Commission finds and concludes Section 328 should not be adopted."

  The proceeding is now closed.

Appendix A – Resources Used for this Report

U.S. Congress

Current and past bills in both the House and the Senate can be viewed at the official Congressional Website: http://Thomas.loc.gov.

U.S. Department of Energy

The Office of Electricity Deliverability and Electricity Reliability has responsibility for both demand response and smart grid activities of the Department. Its website is at: http://www.oe.energy.gov/

Federal Energy Regulatory Commission

FERC maintains a separate section of its website devoted to demand response. It can be found at http://www.ferc.gov/industries/electric/indus-act/demand-response.asp

State Regulatory Commissions

The National Association of Regulatory Utility Commissioners (NARUC) provides a portal to all of the State Commission websites on its home page at www.naruc.org

State Energy Offices and Department of Energy

The National Association of State Energy Officials (NASEO) maintains a portal to all of the State Energy Office/Department websites. It can be found at http://www.naseo.org/members/states/default.aspx

Demandresponseinfo.org

The Demand Response Coordinating Committee sponsors a web site (www.demandresponseinfo.org) that provides up-to-date information about state and federal policy developments and news about other demand response and smart grid developments. Information on the site is available via a searchable library. Free access to the site is available to public officials.

Appendix B – Terminology Used in This Report

Terminology

When new areas like demand response, smart meters, and smart grid arise, there can be even more confusion on terminology and definitions than usual.

Policymakers and stakeholders naturally seek to have "official" definitions of terms. But few energy definitions are ever made official, other than within a specific policy document itself. For example, federal or state tax legislation creating an incentive for smart meters will include a definition of what qualifies as a smart meter. But that definition might be different than a definition that exists in another policy document where funding or grants are being disbursed, or in a policy provision setting forth the rules on how and when utilities will deploy smart metering. Indeed it is the case that an examination of the policies that are described in this report would show a number of different definitions used in different jurisdictions and in different instances.

Another challenge with terminology in these new areas is that in some cases different words are being used interchangeably to mean the same thing, while in other cases people think that different words do not mean the same thing when in fact they do.

However, even if one official definition might not exist for each of the new terms in the area of demand response, smart metering and smart grid, the various definitions, descriptions and interpretations being made do tend to converge on some central points.

The Demand Response Coordinating Committee (DRCC) does have its own definition for demand response, but not for other terms. What follows is the DRCC definition of demand response, followed by a discussion of how terms in this area relate or do not relate to each other.

The DRCC's definition of demand response is:

> "Providing electricity customers in both retail and wholesale electricity markets with a choice whereby they can respond to dynamic or time-based prices or other types of incentives by reducing and/or shifting usage, particularly during peak periods, such that these demand modifications can address issues such as pricing, reliability, emergency response, and infrastructure planning, operation, and deferral."

Several aspects of the definition are worth noting:

- Demand response applies to both *wholesale* and *retail* markets.
- Demand response represents new *choices* for electricity customers.
- Demand response involves a monetary signal that can take the form of a *price* or an *incentive.*
- Demand response can involve either *reducing* usage by totally eliminating an action or *shifting* certain actions from the one period to another period, normally with a net reduction in overall usage.
- Demand response can provide benefits in a number of different areas. These benefit areas in turn can be used as design objectives for demand response programs, products and services, all of which may vary widely while still being considered to be demand response.

Smart Metering

Related terms: *Smart Meter; Advanced Metering; Interval Meter; Advanced Metering Infrastructure (AMI); Automatic Meter Reading (AMR)*

For years, meters placed by utilities on homes and businesses went unchanged. In the 1990's new technologies were introduced by which meter readers could walk or drive by a premise and read a data pulse from the meter. This became known as Automatic Meter Reading (AMR). Other than the automatic read, it did not change metering functionality.

With further advances in metering and communications technology, it became possible to create meters that would measure and present data in intervals—instead of combining all metered usage—allowing it to be used for time-based pricing and other purposes. Also, two-way communications systems meant that data from the meters could be collected over networks faster and more economically. With the addition of the communications system, metering is referred to as Advanced or Smart Metering, and the meter used in such a system is referred to as a Smart Meter. Smart meters are sometimes referred to as Interval Meters, but interval measurement is only one part of advanced or smart metering. Another term in use today is Advanced Metering Infrastructure (AMI), which includes the entire metering system, including the meter, the communications system, and additional elements of the utility communications and data system.

While most often discussed in the context of enabling demand response, smart metering systems provide a number of other benefits in areas such as system planning and optimization, customer service, and outage management and restoration.

Demand Response

Related terms: *Load Management; Direct Load Control (DLC); Dynamic Efficiency*

The term Load Management has been in use for almost three decades in the utility industry. It has generally referred to programs and technologies that allow utilities to place remote control devices on certain customer appliances and equipment. Customers receive monetary consideration in return for letting the utility turn things off on their premise at times of peak demand on the system.

Such Direct Load Control is still in place and in use at a number of utilities. It is still a part of demand response, but Demand Response is in many ways an evolution of load management as it can involve the use of remote communications by utilities and third parties to control devices in customer premises. The technology available today, however, can give customers more control of the devices and can enable automated direct load control of the appliances that contribute to peak load. Demand response, though, goes beyond such device control to include dynamic pricing and other new options for customers. Also, the functionality and capabilities of the new demand response technologies allow two things not done with conventional load management: 1) the creation of demand response networks that control an aggregated load as if it were a peaking power plant on the utility system and 2) the use of demand response not just for emergency purposes but for economic purposes as well. In other words, demand response is increasingly seen as something that can become an integral part of the electricity system and allow optimization of operations, costs and pricing.

Dynamic Efficiency is used to distinguish demand response from traditional energy efficiency. It refers to the ability of demand response to actively manage usage through communications and control systems.

The definition of demand response used by the DRCC can be found above.

Dynamic Pricing

Related Terms: *Time-Based Pricing; Time-of-Use Pricing (TOU); Real-Time Pricing (RTP); Critical Peak Pricing (CPP); Critical Peak Rebates (CPR)*

Most electricity customers are on flat, average pricing today and are not even aware that the cost to produce and deliver electricity fluctuates during the day. Dynamic Pricing refers to types of pricing/rates whereby the price of electricity to the customer can be different at different times of the day or on certain designated days, providing an incentive to customers to reduce some of their peak energy usage. Time-Based Pricing is made possible by smart meters which measure usage in intervals, allowing different prices to be charged for different intervals.

Time-of-Use (TOU) Pricing refers to pricing where large intervals are used (i.e. on-peak and off-peak) and where prices are set for the intervals over long periods of time.

Dynamic Pricing is used to refer to prices that fluctuate more often than with TOU. It includes Real-Time Pricing (RTP), most often thought of as hourly pricing, where the price can change on an hourly basis. Real-time pricing can refer to prices that change in "real-time," but it sometimes refers to hourly pricing where the hourly prices are set on a day-ahead basis. Dynamic pricing also includes Critical Peak Pricing (CPP), where the peak period price is allowed to rise to very high levels on certain designated peak days to reflect the system costs and needs at the time. CPP is normally overlaid on top of a TOU-pricing scheme. Less a type of price than it is a type of incentive, Critical Peak Rebates refers to rebates paid to customers for documented reductions in peak-period use on critical-peak days.

Distributed Resources

Related Terms: *Distributed Generation*

Distributed Resources refers to types of resources to a utility system other than large central generating stations. It normally includes demand response and distributed generation, with the latter typically referring to small generating resources, such as microturbines, but sometimes also including renewable resources such as small biomass and wind or solar installations. Distributed resources may also include traditional energy efficiency in some cases. Distributed Generation (DG) is sometimes included in a demand response application, whereby a customer reduces its draw from the grid during a peak period and uses a DG unit to provide substitute power.

Demand Side Management

Related Terms: *Demand Side Resources*

As utilities in the 1980s began to incorporate energy efficiency and load management into their planning and operations, the term Demand Side Management was coined to refer to utility use of "demand side" as well as supply side resources to find the optimum way to plan and operate its system. The term is still in use today, referring in almost all cases to efficiency and demand response.

Smart Grid

The use of the term Smart Grid has grown considerably just in the past two years. It is being used in different ways by different parties.

In some usage it refers to the concept of a smart grid, where all supply and demand resources are dynamically optimized via a combination of data, communications and controls, and whereby the grid can be operated in optimum fashion from moment to moment. In some usage, "the" smart grid is used to refer to the entire U.S. Grid. In other cases, reference is to "a" smart grid as in a definable grid at the local or regional level that has smart grid characteristics, with those characteristics including such things as being "self-healing" and dynamically flexible. In other usage, smart grid seems to refer to a qualifier for types of technology that help make a grid "smart."

In almost all usage, demand response and smart meters and other smart technologies are considered to be one of the ways that the grid becomes "smart" as connecting customers, their loads, and information about their usage to the grid is essential to the creation and operation of a smart grid.

The Energy Independence and Security Act of 2007, which is described in the Federal section of this report, includes an entire Title on Smart Grid and, while not providing an official definition, does contain provisions that list various characteristics and attributes of a smart grid.

Smart Grid Technologies

Smart meters may be the first technology that comes to mind when thinking of smart grid technologies. There are a number of other technologies, particularly in the area of communications and controls, however, that fall under the usage of this term. These include technologies that can be incorporated into a building as well as those that are used at a higher network level to control many different loads and many different buildings.

Some of the most traditional technologies used for energy efficiency also have smart grid variations. An example would be dynamic lighting systems, which can be operated remotely as part of a demand response system. Another example is energy management systems (EMS) that allow optimization for demand response purposes as well as for overall energy management.

Another example of a smart grid technology area is storage. New systems using ice and other media are allowing the storage of electricity or the storage of a benefit (e.g. heating or cooling) normally derived from electricity. These storage systems can be incorporated into demand response applications and thus into smart grid design and operation.

Appendix C – Members of the National Council on Electricity Policy

National Council on Electricity Policy's Policy Committee

Chair
Jeanne Fox
President
New Jersey Board of Public Utilities

Vice-Chair
Phil Giudice
Commissioner, Division of Energy Resources
Commonwealth of Massachusetts

DOE Representatives

Larry Mansueti
U.S. Department of Energy

EPA Representatives

Kathleen Hogan
Environmental Protection Agency

FERC Representatives

Kevin Kelly
Federal Energy Regulatory Commission

Governor Office Representatives

Edward Garvey
Director, Office of Energy Security
Minnesota Department of Commerce

Morey Wolfson
Governor's Energy Office of Colorado

Public Utility Commission Representatives

Anne C. George
Commissioner
Connecticut Department of Public Utility Control

Patrick J. Oshie
Commissioner
Washington Utilities and Transportation Commission

Phyllis Reha
Commissioner
Minnesota Public Utilities Commission

Marsha H. Smith
Commissioner
Idaho Public Utilities Commission

State Energy Office Representatives

John Sarver
Supervisor, Consumer Education Programs
Michigan Energy Office

Larry Shirley
Director
North Carolina State Energy Office

Dub Taylor
Director, State Energy Conservation Office
Texas Comptroller of Public Accounts

Tony Usibelli
Director, Energy Policy Division
Washington State Department of Community, Trade and Economic Development

State Legislature Representatives

David Dunn
Representative
Arkansas State Legislature

Beverly Gard
Senator
Indiana State Senate

Carl Holmes
Representative
Kansas State Legislature

Hermina M. Morita
Representative
Hawaii State Legislature

Chris Romer
Senator
Colorado General Assembly

National Council on Electricity Policy Representative

Andrew Spahn
Executive Director
National Council on Electricity Council

Appendix D – Demand Response Coordinating Committee

The Demand Response Coordinating Committee (DRCC) is a 501(c)(3) non-profit organization formed in 2004 to undertake activities aimed at increasing the knowledge base in the United States on demand response and facilitating the exchange of information and expertise among demand response practitioners, policy makers, stakeholders, and other interested parties. Among its other activities, the DRCC is the creator and primary sponsor of the premier national event focused on demand response: the National Town Meeting on Demand Response. More information on the DRCC is available at www.demandresponsecommittee.org.

Members of the DRCC at the time of release of this report include:

Ameren

American Electric Power

Arizona Public Service

Commonwealth Edison

DTE Energy

ISO New England

Landis + Gyr

MeterSmart

MidAmerican Energy

Midwest ISO

National Grid

NYSERDA

Pacific Gas & Electric

PJM Interconnection

PPL

Progress Energy

Salt River Project

San Diego Gas & Electric

Southern California Edison

Southern Company

Southwest Power Pool

Tennessee Valley Authority

Wal-Mart

Xcel Energy

The National Council on Electricity Policy Electric Transmission Series:

- *Electricity Transmission: A Primer* (June 2004)
- *Coordinating Interstate Electric Transmission Siting: An Introduction to the Debate* (July 2008)
- *Demand Response and Smart Metering Policy Actions Since the Energy Policy Act of 2005: A Summary for State Officials* (November 2008)
- *Examining Alternatives to Electric Transmission: A Guide for State Officials* (to be released in 2008)
- *The Smart Grid: Policy and Practical Essentials for State Officials* (to be released in early 2009)

NATIONAL COUNCIL ON ELECTRICITY POLICY

The National Council on Electricity Policy (National Council) is a unique venture between the National Association of Regulatory Utility Commissioners (NARUC), the National Association of State Energy Officials (NASEO), the National Conference of State Legislatures (NCSL), National Association of Clean Air Agencies (NACAA) and the National Governors Association (NGA). The National Council also includes participation by the Federal Energy Regulatory Commission (FERC), U.S. Department of Energy (DOE), and the U.S. Environment Protection Agency (EPA). Established in 1994, the National Council enables better coordination between federal and state entities responsible for electricity policy and programs. Our members understand that improved intrastate, regional and federal coordination can result in more informed electricity policy decisions.

For more information on National Council on Electricity Policy please visit:
www.ncouncil.org