Modernizing the Electric Power Grid: An Analysis of U.S. Smart Grid Policies

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ABSTRACT

In recent years, increasingly higher stakeholder expectations in the energy sector coupled with an aging electric power grid has led to a growing focus on our nation's approach to energy management and grid modernization. A number of states have adopted or proposed laws, regulations, and voluntary or mandatory requirements regarding smart grid. The Energy Independence and Security Act of 2007, Title XIII, promotes the development and implementation of smart grid and establishes a national policy for grid modernization; this is supported by the disbursement of almost $4.5 billion of Recovery Act funding.

This research project investigates whether states receiving Recovery Act funding are adopting policies that align with the objectives defined by Title XIII, Sec. 1301 of the Energy Independence and Security Act of 2007 (EISA). I address this question with a policy analysis of the five states that have received the largest amounts of Recovery Act funding. I focus on policies regarding distributed generation and net metering, Advanced Metering Infrastructure (AMI) deployment plans, AMI data privacy and security, and energy efficiency.

Section 1
INTRODUCTION

A growing focus on our nation's approach to energy management signifies serious change for the United States. Stakeholders in the energy sector have increasingly higher expectations that are challenging the current business and regulatory models model and highlighting its limitations. Our quest for energy independence and fuel diversity is paralleled not only by the continual advancement of renewable and energy-efficient technologies, but also by the evolution of business models and regulation in the U.S. power sector. The advancement of the energy sector has differed region to region, but there is a clear movement away from vertically integrated monopolies toward an interconnected, competitive marketplace.

There is growing realization that infrastructure of the electric power grid has become outdated and current physical assets are incapable of meeting expected future needs for sustainable electric power. Stakeholders in the electric power industry will require substantial investments in infrastructure to ensure a secure and reliable energy supply. A key product of this transition is the emergence of smart grid technology. Like the term "sustainability", smart grid has an abundance of definitions. The majority of these definitions circle back to the idea that the smart grid is "a transformed electric network whose scope can range from main station generation to end-use customer appliances that utilize robust two-way integrated communications, computing/IT technologies, advanced sensors and controls, and innovative applications to operate more efficiently, reliably and safely while enhancing service and choice for customers" (West, 2010). Essentially, smart grid refers to the modernization of our current electric grid.

Technologically, smart grid promises to create cleaner, more efficient electricity use as it adds monitoring, analysis, control and communication capabilities to the national electric grid. From a policy perspective, the smart grid promises to integrate energy from a greater diversity of resources; increase efficiency; increase reliability and responsiveness; increase choice and competition; enhance security; and provide greater transparency in pricing and performance (Imhoff, 2011).

At the same time, smart grid technology also raises a multitude of concerns. Issues with data security and privacy and regarding the impact on utility costs are the most widely discussed smart grid concerns. A modernized electric grid will collect, communicate, and store detailed operational data from tens of thousands of sensors as well as consumption data from millions of individual consumers. The detailed data that will be collected is intended to be used by utilities as a tool for making more informed decisions regarding outages, changes in load, and customers billing. However, customers are concerned about how much data is collected, where it is stored, who has access to it, and how we can ensure that data is properly controlled and protected (Kassakian, Hogan, Schmalensee, & Jacoby, 2011).

There are also concerns that about who will bear the financial burden of grid modernization. The Electric Power Research Institute estimates that the implementation of a fully functional smart grid will cost anywhere from $338 billion to $476 billion (Kanellos, 2011). Although the Recovery Act's allocation of $4.5 billion to the Department of Energy for smart grid initiatives provides a significant amount of funding, it only accounts for approximately 10 percent of the estimated cost of grid modernization. There is concern that utilities will be responsible for bearing the remaining costs and that in turn, ratepayers will see substantial rate increases.

The current regulatory framework of electric power industry allows policies to vary greatly from one state to the next (Kassakian, Hogan, Schmalensee, & Jacoby, 2011). If smart grid is going to be successful, a stronger federal role will be needed to ensure consistency in state-level policies and efficiency in implementation. Policy should be designed with the goal of reliably and sustainably connecting sources of electric power to sources of demand in real-time, wherever those sources happen to be located, while providing information and incentives that encourage sustainable generation and use.

This paper explores the present state of the electric power grid and the regulatory framework in which it operates. Specifically, this research addresses the hypothesis that states that have received Recovery Act funding for smart grid initiatives are adopting policies that align with the objectives defined by Title XIII, Sec. 1301 of the Energy Independence and Security Act of 2007 (EISA).

To answer this question, this paper will first define the problem and situate it in historical context. The electrical grid today is a complex elaboration on a basic model of central power generation at large plants and the transmission of that power across long-distance, high voltage-distribution systems to customers spread across a wide area. For the most part, the regulatory system has evolved alongside the technology. Regulators recognized early both the advantages and drawbacks of large utilities acting as monopolies, and proceeded over several decades to fashion a regulatory system that would balance the needs of utility owners and stakeholders with the public interest.

After providing a historical context, the paper will explore the current policy environment, identifying areas that will need to be shored up in the interests of enabling grid modernization to proceed. This section will close with a discussion of the primary objectives of Title XIII, Section 1301 of the Energy Independence and Security Act.

Finally, this paper will discuss whether the states analyzed are adopting policies that align with the objectives of Section 1301 and will outline policy recommendations geared to achieving the objectives that are not currently being met. This includes the development of a national advanced metering infrastructure deployment plan.

Statement of Problem

Today’s electricity grid is comprised of more than 9,200 electric generating units with more than 1 million megawatts (MW) of generating capacity connected to over 300,000 miles of transmission lines (U.S. Department of Energy, 2011). The grid’s assets are rapidly aging and will soon be outdated, requiring a significant investment in capital to either replace or upgrade our power system and to enable necessary expansion to meet future load growth (Kassakian, Hogan, Schmalensee, & Jacoby, 2011).

As our current electric grid ages, we’re seeing an increase in power interruptions and major outages. It is estimated that customers in the U.S. can expect between 1.5 and 2 power interruptions per year and between 2 and 8 hours without power (Kassakian, Hogan, Schmalensee, & Jacoby, 2011). Data collection on outages is inconsistent, incomplete and is only required in 35 states (Eto & LaCommare, 2008). Lack of quality data makes it difficult for utilities to understand outage patterns and decreases utility response time when an outage occurs. Implementation of smart grid technologies will increase the quantity and quality of data collected through advanced metering infrastructure, which will enable utilities to be more informed and responsive to reliability issues.

In addition to reliability issues, the electric grid is vulnerable to attack from cyber and physical threats. Our current dependence on technology means that an extended loss of today's grid could be catastrophic to multiple facets of our daily lives, particularly to our security, economy and quality of life. A smarter, more modern grid will be "self-healing" in that it will sense when reliability issues may occur and automatically reroute power to reduce the number of customers affected by power outages. Similarly, it will also be capable of resisting concurrent attacks against several parts of the system and of detecting, responding to, and mitigating disturbances (The NETL Modern Grid Initiative, 2007). Simply put, modernizing the grid will allow us to move from a reactive model to a proactive one.

Our current grid was not designed with 21st century power supply challenges in mind. As the U.S. strives to reduce our dependency on fossil fuels and foreign oil, we must continue to diversify our fuel sources and generation types. A smarter, more modern grid will address these challenges and will facilitate a seamless integration of various fuel and generation types; a modernized grid will also make it easier for commercial and industrial users to install their own generation and storage facilities. It will allow large environmentally-friendly central plants to integrate energy sources such as renewables, particularly wind and solar, into the transmission system to supplement our current generation fleet of coal, oil, and nuclear plants (The NETL Modern Grid Initiative, 2007).

In the present regulatory environment, utilities have little incentive to give customers tools they need to reduce their consumption of electricity. Modernizing the grid will be expensive and time-consuming. As mentioned earlier, it is estimated that the implementation of a fully functional smart grid will cost $338 billion to $476 billion (Kanellos, 2011). In light of their status as regulated monopolies, public utilities are limited in their ability to raise and invest capital; it is unlikely that they will be able to invest in new, cleaner, more sustainable generation and transmission technologies without assurance that they'll be able to earn an equitable return on their investment.

In December 2007, Congress passed the Energy Independence and Security Act of 2007. Title XIII of EISA addresses grid modernization and established the development of the smart grid as a national priority by providing the legislative support for Department of Energy's smart grid activities. EISA also reinforced the DOE's role in leading and coordinating national grid modernization efforts. A key provision of Title XIII is Section 1301 Statement of Policy on Modernization of Electricity which states, "It is the policy of the United States to support the modernization of the Nation's electricity transmission and distribution system to maintain a reliable and secure electricity infrastructure that can meet future demand growth and to achieve each of the following, which together characterize a Smart Grid" (U.S. Department of Energy, 2011).

Not long after the enactment of EISA, the Department of Energy received a budget of roughly $4.5 billion for grid modernization initiatives under the American Recovery and Reinvestment Act of 2009 (U.S. Department of Energy, 2011). The Recovery Act funds a large number of local and state level initiatives through the Smart Grid Investment Grant Program. As such, it important to understand if states receiving large amounts of Recovery Act funding for grid modernization projects are implementing policies that facilitate the development of a smart grid as characterized by Title XIII, Section 1301 of the Energy Independence and Security Act of 2007.

Section 2
METHODOLOGY

This capstone is a qualitative policy analysis that explores how current state-level smart grid policies align with the goals defined by Section 1301 of Title XIII of the Energy Independence and Security Act of 2007. This paper will first define the problem and situate it in historical context, outlining the regulatory framework in which the electric power grids operates and the recent emergence of federal smart grid policy.

This paper will then examine adopted smart grid policies of five states: California, Florida, New York, Pennsylvania and Texas. My primary sources of data for this analysis were the Energy Information Administration, the Database for State Incentives for Renewables & Efficiency (DSIRE), the Edison Electric Institute, the Galvin Electricity Initiative, and regulatory documents from state public utility commission websites.

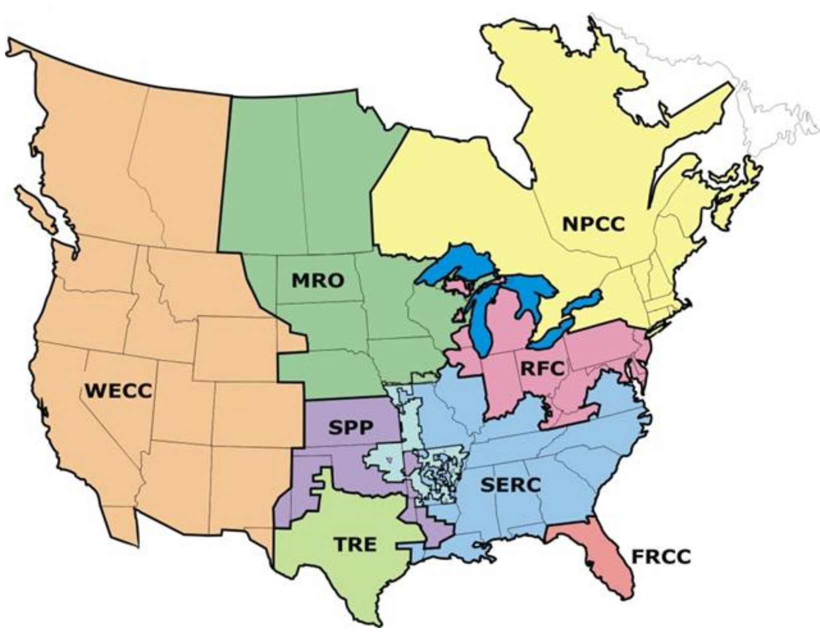
The states included in my study were selected by the amount of Recovery Act funding that they have received as of June 1, 2010 as this is the last released report by the Department of Energy (Table 2-1).

Table 2-1
ARRA Funding Received ($000)

	ARRA Funding Received[1]
California	$393.2
Florida	$395.2
New York	$276.0
Pennsylvania	$243.8
Texas	$292.8

After identifying the ten states receiving the largest amount of funding, I categorized states using their North American Electric Reliability Corporation (NERC) region (Figure 2-1) and then chose the five states that had the highest amount of funding that also represented five different regions. NERC works with eight regional entities to improve the reliability of the bulk power system. Although regional location was not a variable in my study, this manner of selection ensured a reasonable degree of equal geographical representation in my analysis.

Figure 2-1
Map of North American Electric Reliability Corporation's Regions



Each state was evaluated on whether or not it has adopted policies targeted to achieving the following objectives:

- Increased deployment of distributed generation and net metering
- Development of advanced metering infrastructure deployment plans
- Implementation of Advanced Metering Infrastructure Data Privacy / Security

- Improved Energy Efficiency

The listed policies are among the ten objectives of grid modernization that are defined by Section 1301. As such, I considered progress toward achieving these policy objectives to be a leading indicator that states have fulfilled the intent of Title XIII. These policies, and their justification for inclusion in this study are outlined below.

Increased Development of Distributed Generation and Net Metering Plans

The first policy considered was distributed generation and net metering. Distributed generation is the generation of electricity at the point of consumption, typically to supplement purchased power or to use for emergency power during outages. Distributed generation can be utilized by all customer classes, but is most commonly used by residential, commercial and industrial customers. Generating power onsite to replace, or supplement, purchased power offers a host of benefits. In addition to reducing costs associated with purchasing power, distributed generation reduces increases electricity reliability.

Advances in materials and designs for technologies such as photovoltaic panels, reciprocating engines, fuel cells, digital controls, and remote monitoring equipment, have increased the number of opportunities and applications for distributed generation. These advances have also enabled consumers to tailor energy systems that meet their unique needs. As we begin the inevitable shift toward a smarter, more modern grid, consumers are seeing increased opportunities to use distributed generation. We are also seeing an increase in electric utilities exploring distributed generation as an option for supplementing traditional generation (The NETL Modern Grid Initiative, 2007).

Net metering is a mechanism that is used to encourage customers to invest in renewable energy technologies(U.S. Department of Energy, 2011). Net metering allows customers to use their own generation from on-site renewable energy systems to offset their consumption over a billing period which is a huge incentive for customers to participate. When customers generate more electricity than they use, they are essentially giving energy back to the grid rather than taking energy from it. The quantity of energy that they give back to the grid is recorded by their meter and they receive compensation for the excess energy that they produced. Net metering gives customers with small renewable energy generators an opportunity maximize the value of the energy that they produce and gives them more flexibility in their consumption. Providers, in this case utilities, also benefit because the system load factor is improved when customers are producing electricity and feeding it back into the grid during peak periods (U.S. Department of Energy, 2011).

The third objective of Section 1301 is to increase integration of distributed resources and generation, including renewable resources (U.S. Department of Energy, 2011); adoption of distributed generation and net metering policies indicates that states have fulfilled this objective. It also indicates that states are encouraging the use of clean, renewable energy which works toward decreasing our dependence on foreign fuel sources.

Development of Advanced Metering Infrastructure Deployment Plans

The second policy considered was the adoption of a plan to deploy an advanced metering infrastructure (AMI) within a certain period of time. AMI refers to systems that incorporate automated meter reading, two-way communications and data management. It is most commonly discussed in terms of “smart meters”; smart meters provide consumers with real-time information on their energy consumption. This helps engage customers by enabling them to control and manage their energy use. Smart meters also provide utilities with more accurate consumption information which improves billing (National Energy Technology Laboratory, 2008).

The fifth objective of Section 1301 is to deploy `smart’ technologies (real-time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices) for metering, communications concerning grid operations and status, and distribution automation (U.S. Department of Energy, 2011). Development of advanced metering infrastructure deployment plans is crucial to successful implementation of smart grid technologies because signifies an increase in the quantity and quality of data that utilities receive. This in turn increases utilities’ ability to respond to changes in load demand; it also increases responsiveness to issues regarding reliability which allows for more reliable and efficient energy use.

Implementation of Advanced Metering Infrastructure Data Privacy / Security

Policies regarding advanced metering infrastructure data privacy and security are intended to protect customer information through controlled access to usage and price data. AMI systems inherently create data privacy and security risks because of the nature and volume of the information they collect. Meters are designed to collect information related to a particular household or business. Currently, each meter has a unique identifier, timestamp, usage data, and time synchronization every 15 to 60 minutes. Smart meters will also collect this data as well as outage, voltage, phase, and frequency data (Foley, 2008). There is concern that collecting and storing more detailed data will enable utilities and third-parties to monitor whether or not customers are at home and if they are home, what they are doing.

The tenth objective of Section 1301 is to identify and lower unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (U.S. Department of Energy, 2011). Adoption of policies regarding AMI data privacy and security is an indicator of progress toward fulfilling the intent of Title XIII because these policies reduce barriers to successful implementation. AMI data privacy and security policies will minimize customer concerns about the security of usage and account data.

Improved Energy Efficiency

The last policy considered was the existence of energy efficiency policy, particularly policies in the form of energy efficiency resource standards (EERS). These are state-level policies that require utilities to meet specific targets for energy savings according to a set schedule. EERS policies are typically designed to set reduction targets for electricity sales and/or peak electric demand. EERS policies often include requirement for compliance. This typically includes a financial incentive encouraging customers to install energy-efficient equipment (Glatt & Schwentker, 2010).

Improved energy efficiency is considered an indicator of progress toward fulfilling the intent of Title XIII because it addresses the fourth objective outline by Section 1301: Development and incorporation of demand response, demand-side resources, and energy efficiency resources (U.S. Department of Energy, 2011).

Section 3
LITERATURE REVIEW

Background

Thomas Edison introduced the first in-office electricity in September, 1882. The Pearl Street station, the first central generating plant in the U.S., allowed J.P. Morgan to turn on hundreds of bulbs in his Wall Street office at the same time that dozens of bulbs went on in the New York Times offices (Yergin, 2011). Initially, Edison's direct current (DC) system served 59 customers in the Wall Street area at a price of about $5 per kilowatt hour (kWh) (Kassakian, Hogan, Schmalensee, & Jacoby, 2011). This technology was simply unheard of and as such, Edison is often given credit for the genius of subdivided light.

George Westinghouse also played an instrumental role in the development of electricity. In 1896, Westinghouse introduced the use of transmission by locating generating stations far from consumption centers. The Niagara Falls hydroelectric plant was used to generate large amounts of power that were then transmitted to Buffalo, New York, over 20 miles away. In collaboration with an English engineer, Westinghouse developed a revolutionary transformer that could "step down" alternating current (AC) electricity from the high voltage needed to carry it long distances to a lower voltage that was more suited to the end use (Massachusetts Institute of Technology, 2008). Westinghouse's plant at Niagara was the first large system to supply electricity from one circuit for multiple end-uses. With Niagara, Westinghouse demonstrated that transmitting power with electricity, rather than mechanically, was far more efficient. He also demonstrated that alternating current was superior to direct current (Massachusetts Institute of Technology, 2008).

While Edison and Westinghouse developed the technology and introduced a rudimentary concept of the electricity grid, it was Samuel Insull, a former member of Edison’s staff, who developed the industry structure and business model that fostered the growth of contemporary electricity and the current electric grid (Fox-Penner, 2010). Insull’s vision of the electric industry was based on four key concepts: that it is cheaper to serve customers when their power use is aggregated via the largest possible web of interconnections; economies of scale in production; sell more and charge less; and that regulation provides stability and protection to an industry with declining costs and high capital needs (Fox-Penner, 2010). Those factors, in combination with an increasingly intensive political interaction made it evident to Insull that the electricity industry would gain stability and protection from regulation.

In the early 1900s, electric utilities spread rapidly. Initially, utilities were primarily municipally-owned, but as generator technology advanced and efficiencies grew, private multiservice systems began to replace smaller private and municipal companies. The emergence of larger, private multiservice systems brought the development of large utility holding companies, each "holding" controlling interest in a number of electric utilities (U.S. Energy Information Administration, 2001).

As utility companies grew in size their service areas expanded accordingly. In 1907, Georgia, New York, and Wisconsin established public service commissions to regulate the utilities’ rates, financing, and service, and to establish standardized utility accounting systems (U.S. Energy Information Administration, 2001). As utility service areas expanded beyond state lines, it became apparent that States could not regulate an interstate holding company.

The federal government's involvement in the electric utility industry really began expand in the early 1930s when they became a regulator of private utilities and a major producer of electricity (Energy Information Administration, 1996). The Public Utility Holding Company Act of 1935 (PUHCA) was passed to facilitate the regulation of electric utilities. Under PUHCA, utilities involved in interstate wholesale marketing or transmission of electric power became regulated by the Federal Power Commission (FPC), which became the Federal Energy Regulatory Council (FERC) in 1977 (U.S. Energy Information Administration, 2001).

Shortly after enacting PUHCA in 1935, the federal government encouraged the growth of rural electricity through passage of the Rural Electrification Act of 1936 (REA). REA provided loans and assistance to organizations providing electricity to rural areas with populations under 2,500 to encourage the formation of rural electric cooperatives (U.S. Energy Information Administration, 2001). By 1941, 35 percent of rural homes had electricity; this was almost three times more than that of 1932 (U.S. Energy Information Administration, 2001).

The federal government began to provide less expensive electricity to cooperatives and municipalities (Energy Information Administration, 1996). Projects such as the Hoover Dam in 1936, the Bonneville Project in 1937, and the formation of the Tennessee Valley Authority solidified the federal government's role in the electric power industry.

Electric generating systems continued to expand in size and demand throughout the 1940s and the federal government was, by that point, a strong player in the electric power industry. By 1941, public power contributed 12 percent of total utility generation; the federal government alone contributed almost 7 percent (U.S. Energy Information Administration, 2001). As electric generating systems continued to grow, the price of electricity continued to decline. By 1945, almost half of all rural homes were electrified (U.S. Energy Information Administration, 2001).

The utility industry continued to grow, from 1950 to 1960; generation grew by an average of 8.5 percent annually and capacity grew by an average of 9.5 percent annually (U.S. Energy Information Administration, 2001). The growth in residential electricity was paralleled by significant advancements in the commercial sector; commercial nuclear power was introduced in the 1950s. In 1954, the Atomic Energy Act was enacted, allowing private development of commercial nuclear power (U.S. Energy Information Administration, 2001). The Price-Anderson Act was adopted in 1957, further encouraging the development of nuclear power generation by reducing private liability and guaranteeing public compensation should a commercial nuclear catastrophe occur (American Nuclear Society, 2005). The country's first central station commercial nuclear reactor, located in Shippingport, Pennsylvania, began operation in 1957 (U.S. Energy Information Administration, 2001).

Throughout the 1960s, electricity continued to see high growth rates due largely to overall economic growth, declining real energy prices, and growing consumer preference for the convenience and versatility that electricity offered. The 1960s also brought technological advances such as automated controls and computers. These advances, coupled with continued high demand growth, encouraged utilization of nuclear facilities, and nuclear power generation increased to over 1 percent of the U.S. total by 1970 (U.S. Energy Information Administration, 1985).

Although U.S. utilities experienced growth in the 1960s, they also encountered new challenges. In 1965, the Northeast experienced a major blackout which raised concerns about the reliability of the grid. In response, the electric utility industry formed the North American Electric Reliability Council (NERC), which was later renamed the North American Electric Reliability Corporation (Kassakian, Hogan, Schmalensee, & Jacoby, 2011). Under NERC, nine regional reliability organizations were formalized as were regional planning coordination guides, which NERC maintained. Compliance with these operations criteria and guides was strongly encouraged, but compliance was ultimately voluntarily (NERC, 2012).

In the 1970s, the electric power industry experienced new conservation and energy efficiency efforts. Decreasing unit costs and rapid growth shifted to increasing unit costs and slower growth (U.S. Energy Information Administration, 2001). This was due largely to ambitious capital expansion programs, a drastic increase in fossil-fuel prices, and an increase in environmental regulation. The Clean Air Act of 1970 and its amendment in 1977 required utilities to reduce pollutant emissions (US Environmental Protection Agency, 2012). This caused capital, operating, and fuel costs to increase which in turn increased electricity rates. Nuclear power grew rapidly from 1971 to 1974: 131 new nuclear units, each with an average capacity of 1,100 megawatts, were ordered (Energy Information Administration, 1984). Nuclear power's rapid growth was short-lived, however, and by 1979 the Nuclear Regulatory Commission had closed five operating reactors due to safety concerns. This, in combination with the accident that occurred at Three Mile Island, a reactor near Harrisburg, Pennsylvania, heightened public concerns and demand for nuclear power fell as quickly as it had risen (U.S. Energy Information Administration, 2001).

In 1978, Congress passed the Public Utility Regulatory Policies Act (PURPA), which required regulated electric utilities to buy power from non-utility generators using cogeneration, renewable resources, or other selected at the utility's "avoided cost" of generation (Kassakian, Hogan, Schmalensee, & Jacoby, 2011), (U.S. Department of Energy, 2012).

In the 1980s, a new model for power system organization in which the price of wholesale electricity was determined by competitive markets emerged (Joskow & Schmalensee, 1983). This model separated ownership of generation from the rest of the system and enabled independent entities to operate the transmission system and administer wholesale markets. Theoretically, this model would rely on markets to perform the coordinating and cost-minimizing functions that had been traditionally performed within vertically integrated utilities. In the United States, excess capacity increased the appeal of this model as it was assumed that competitive market prices for electricity would be less than regulated prices (Kassakian, Hogan, Schmalensee, & Jacoby, 2011).

By 1991, non-utilities owned approximately 6 percent of the generating capacity and 9 percent of the total electricity generated in the United States (Edison Electric Institute, 1992). In 1992, Congress passed the Energy Policy Act (EPAct 1992). EPAct 1992 defined goals, created mandates, and amended utility laws to increase use of clean energy and improve energy efficiency in the U.S. EPAct 1992 is comprised of twenty-seven titles detailing various measures that were designed to decrease the nation's dependence on imported energy while providing incentives for clean and renewable energy and promoting energy conservation (U.S. Department of Energy, 2009).

EPAct 1992 also amended the Public Utility Holding Company Act of 1935 to help small utility companies stay competitive with larger utilities. EPAct 1992 also amended PURPA, increasing resource choices for utility companies and outlined new rate-making standards. There are separate sections detail clean energy incentives, research & development strategies, conservation goals, and responsible management practices regarding oil, coal, natural gas, and nuclear energy (U.S. Department of Energy, 2009).

In 1996, FERC issued Order No. 888, which required transmission owners to provide wholesale customers open access to their systems (Federal Energy Regulatory Commission, 2010). A few years later, in 1999, FERC issued Order No. 2000, which defined Regional Transmission Organizations (RTOs) as independent system operators (ISOs) that have demonstrated compliance with a specific set of requirements. Order No. 2000 strongly encourages utilities to affiliate with RTOs and ISOs, but does not require them to (Kassakian, Hogan, Schmalensee, & Jacoby, 2011).

In 1996, the State of California passed AB 1890, *The Electric Utility Industry Restructuring Act*, which deregulated California’s electricity market and allowed for competition. Prior to enactment of AB 1890, a single utility provided each customer with generation, transmission, distribution, and metering and billing of electricity; AB

1890 allowed most customers to choose their electric generation supplier (Energy Information Administration, 2008).

Introducing completion was intended to decrease the cost of electricity in California (Yergin, 2011). However, in 1996, the average revenue per kilowatt-hour of electricity sold in California was 9.48 cents, the 10th highest among the 50 States and the District of Columbia; the U.S. average price was 6.86 cents per kilowatt-hour. California's electricity rates remained substantially higher than those in the rest of the country between 1996 and 1999. This paralleled an overall demand increase of 11.3 percent, a decrease of 1.7 percent generating capacity, and a 13.0 percent population increase in California (Energy Information Administration, 2002).

By 2000, demand for electricity had surpassed supply and California ratepayers were experiencing rate fluctuations and rolling blackouts. As the shortage of electricity worsened, utilities found themselves sourcing power on an hour-to-hour basis, not knowing how the price might change from one hour to the next (Yergin, 2011). Many business had "interruptible" contracts, which meant that they paid a lower rate and agreed that they could be temporarily removed from the grid in the event of an electricity shortage (Yergin, 2011). Businesses with interruptible rates began experiencing frequent losses of power with little notice.

In June 2000, the California Public Utilities Commission (CPUC) reduced the buy-side price cap for real-time, ancillary services to $500 per megawatt; the CPUC reduced the price cap again on August 1, 2000, this time to $250 per megawatt (Energy Information Administration, 2005). On August 31, 2000 the California legislature passed AB 265 which established a rate cap of 6.5 cents per kWh for San Diego Gas & Electric customers (Bowen, 2001).

By December 2000, FERC became involved and issued an order that reversed the mandatory requirement that Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric purchase and sell all of their power through the California Power Exchange; FERC also eliminated the Exchange's wholesale rate schedule (Energy Information Administration, 2005).

In 2001, FERC continued to play an instrumental role is repairing California's electricity market and facilitated the stabilization of California's electricity market. California was once seen as a leader in the shift toward reliance on deregulated electricity markets in the 1990s and its energy crisis was an unfortunate example of the flawed market design (Kassakian, Hogan, Schmalensee, & Jacoby, 2011). Though other states experimented with deregulation, California's situation was unique and drew attention to the growing inconsistencies among state policies. The California energy crisis, and the role that FERC played in remedying California's electricity market, highlighted the need for federal involvement in state electricity markets.

Current Policy Framework

Energy Policy Act of 2005

The Energy Policy Act of 2005 (EPAct 2005) was the first major energy law enacted in more than a decade and signified the beginning of serious changes in the electric utility industry. EPAct 2005 established a number of energy management goals for federal buildings and fleets regarding metering and reporting, energy-efficient product procurement, energy savings performance standards, renewable energy requirements, and alternative fuel use (U.S. Department of Energy, 2010).

EPAct 2005 did not require utilities to begin implementing smart meters, but it did require that states start considering the introduction of smart meters and variable pricing. EPAct 2005 also established incentives for energy efficiency and for implementation of advanced transmission technologies (U.S. Department of Energy, 2010). Incentives for energy efficiency were offered in the form of tax incentives for commercial buildings, new homes, residential heating and cooling equipment, shell improvements for existing homes, high-efficiency appliances, high-efficiency vehicles, and stationary fuel cell systems. Tax credits ranged from as little as $75 for appliance replacements to as much as $2,000 credits for new construction homes that exceeded ASHRAE standards' criteria by 50% (Prindle, 2006).

In addition to establishing new energy management goals, EPAct 2005 repealed PUHCA, effective on February 8, 2006. PUHCA was replaced by the Public Utility Holding Company Act of 2005 (PUHCA 2005). Under PUHCA 2005, FERC gained responsibility for allocating the costs of multi-state electric utility holding companies to individual operating subsidiaries (Federal Energy Regulatory Committee, 2005).

Energy Independence and Security Act of 2007 (EISA)

In December 2007, legislature passed Title XIII of the Energy Independence and Security Act of 2007 (EISA). EISA established the development of the smart grid as a national priority by providing the legislative support for Department of Energy's smart grid activities. EISA also reinforced the DOE's role in leading and coordinating national grid modernization efforts.

A key provision of Title XIII is Sec. 1301 Statement of Policy on Modernization of Electricity which states that “It is the policy of the United States to support the modernization of the Nation’s electricity transmission and distribution system to maintain a reliable and secure electricity infrastructure that can meet future demand growth and to achieve each of the following, which together characterize a Smart Grid:

1. Increased use of digital information and controls technology to improve reliability, security, and efficiency of the electric grid.
2. Dynamic optimization of grid operations and resources, with full cyber security.
3. Deployment and integration of distributed resources and generation, including renewable resources.
4. Development and incorporation of demand response, demand-side resources, and energy efficiency resources.
5. Deployment of `smart’ technologies (real-time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices) for metering, communications concerning grid operations and status, and distribution automation.
6. Integration of `smart’ appliances and consumer devices.
7. Deployment and integration of advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning.
8. Provision to consumers of timely information and control options.
9. Development of standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid.
10. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services.” (U.S. Department of Energy, 2011).

The Act also stipulates that the government sponsor initiatives that invest in smart grid through coordinated research, development, demonstration, and information outreach efforts (U.S. Department of Energy, 2011).

The America Recovery and Reinvestment Act of 2009

The American Recovery and Reinvestment Act of 2009 (Recovery Act) provides the DOE with a budget of roughly $4.5 billion to modernize the electric power grid and to implement Title XIII of the Energy Independence and Security Act of 2007 (U.S. Department of Energy, 2011).

The Recovery Act funds local and state level initiatives through the Smart Grid Investment Grant Program (SGIG). SGIG is responsible for awarding grant funding for smart grid projects. Eligible projects must be administered by non-profit organizations, for-profit consulting companies, and localities; they must also be designed to implement smart grid technologies and techniques to improve the performance of our current grid. The Department of Energy estimates that as of November 15, 2011, SGIG has awarded approximately $3.4 billion of grant funding for 102 smart grid projects (U.S. Department of Energy, 2011). Projects that were awarded funding fell into one of the following categories: advanced metering infrastructure, customer systems, electric distribution, electric transmission systems, or equipment manufacturing (U.S. Department of Energy, 2011). Recovery Act grants are intended to fund projects, not policy development, and have strict requirements with which funding recipients must comply. These requirement are not discussed in this report as they are not associated with policy development.

The Recovery Act's federal programs also include workforce training and development activities, consumer behavior studies, and standards, interoperability, and cyber security activities. Additionally, under the Recovery Act, the DOE's Office of Electricity Delivery and Energy Reliability is tasked with managing the Smart Grid

Demonstration Program (SGDP). The SGDP researches and evaluates advanced smart grid and energy storage systems for future applications (U.S. Department of Energy, 2011).

Federal vs. State Jurisdiction

It is important to understand how state and federal roles differ regarding jurisdiction over the electric power industry. Some aspects of the industry, such as interstate transmission and wholesale power sales, are federally regulated; some, such as retail rates and distribution service, are state-regulated; and some, such as facility siting and environmental impacts, may be regulated at the local level (The Regulatory Assistance Project, 2011).

The Federal Energy Regulatory Commission (FERC) handles the majority of the federal regulation of the energy sector, but some activities are regulated by the Department of Energy (DOE), Department of Defense (DOD), Environmental Protection Agency (EPA), the Bureau of Land Management (BLM), or other federal bodies (Brown & Salter, 2010).

State regulators oversee the prices and terms of service for electricity provided by investor-owned utilities; they also regulate quality of service standards and construction standards for lower-voltage retail distribution facilities. In some states, they are responsible for regulating consumer-owned (i.e., cooperative and municipal) utilities as well.

Historically, there has been tension between states and federal government regarding electricity regulation as each believes it has the greater authority and as such, it is rare that one will voluntarily cede authority to the other. If smart grid implementation is truly going to be successful, there needs to be coordination between state and federal entities.

Section 4
RESULTS AND DISCUSSION

State Policy Results

California

Among the states included in this analysis, California is the leader in smart grid policy adoption. California has aggressively pursued smart grid policies and federal funding to support their smart grid initiatives. As of June 2010, California had received a total of $2.3 billion for selected DOE projects (U.S. Department of Energy, 2011). Of that $2.3 billion, $393.2 million has been allocated to grid modernization initiatives, primarily regarding Smart Grid Investment and Demonstration Projects ($385.7 million), State and Local Energy Assurance and Regulatory Assistance ($6 million), and Smart Grid Workforce Training ($1.5 million) (U.S. Department of Energy, 2011).

Distributed Generation & Net Metering

In 1996, the California Public Utility Commission (CPUC) passed California Public Utilities Code §2827, et seq. which required the majority of utilities to offer net metering. Publicly-owned electric utilities companies with 750,000 customers or more that also provide water are exempt from offering net metering; Los Angeles Department of Water and Power (LADWP) is the only utility that is exempt from this law (North Carolina State University, 2012). The law has been amended multiple times since its enactment, most recently in October 2011.

Solar thermal electric, photovoltaics, landfill gas, wind, biomass, geothermal electric, fuel cells, municipal solid waste, anaerobic digestion, small hydroelectric, tidal energy, wave energy, and fuel cells using renewable fuels are all eligible to participate in net metering (North Carolina State University, 2012).

In 2010, California's legislature passed AB 510, which set the aggregate limit of net-metered systems in a utility's service territory to 5 percent of the utility's total customer peak demand. AB 510 doesn't provide a methodology for calculating "aggregate peak customer demand" and as such, California's three investor-owned utilities (Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric) are calculating their net metering caps differently. In April 2012, the CPUC addressed this issue by proposing a decision to more clearly define "aggregate customer peak demand" for all utilities (North Carolina State University, 2012).

AMI Deployment Plans

In 2003, the CPUC passed Decision 03-06-032 which initiated the State's exploration of advanced metering infrastructure (Brown & Salter, 2010). In 2009, California passed SB 17 which was one of the first state bills to specifically endorse the development of smart grid. It required all utilities with more than 100,000 connections to submit a smart grid deployment plan to the CPUC by July 1, 2011 (California Public Utilities Commission, 2009). In 2010, California passed AB 37, An Act to Add Section 8370 to the Public Utilities Code, Relating to Electricity, and Declaring Urgency Thereof, to Take Effect Immediately which mandates that the CPUC require utilities to allow customers to decline smart meter installation and to offer customers an alternative meter option (Huffman, 2010).

AMI Data Privacy & Security

In 2009, the California Public Utilities Commission adopted *CA EISA Adoption*, which outlines requirements regarding consumer and third-party access to usage and price data (California Public Utilities Commission, 2009).

In 2011, the CPUC adopted Rulemaking 08-12-009, Decision 11-07-056, SB 1476 Decision Adopting Rules to Protect the Privacy and Security of the Electricity Usage Data of the Customers of Pacific Gas and Electric Company, SCE, and San Diego Gas and Electric Company. SB 1476 outlines rules regarding the privacy and security of customer usage data and limits customer and third-party access. The bill ensures that customers are provided with the opportunity to opt-out of their consumption data being shared with a third-party by the utility providing the service (Padilla, 2010).

Energy Efficiency

In 2006, the California Legislature enacted AB 2021, which emphasized the importance of energy efficiency and established broad reduction goals. This included the goal of reducing forecasted electricity consumption by 10 percent by the year 2016 (North Carolina State University, 2012). The bill also requires the development of a statewide estimate of all cost-effective electricity. It also requires that efficiency savings and demand reduction targets be established and that said targets must be by the year 2020; these targets are outlined in Tables 4-1 and 4-2 (American Council for an Energy-Efficient Economy, 2012).

Table 4-1
California Electricity Savings Requirements (GWH)

	2012	2013	2014	2015	2016	2017	2018	2019	2020
PG&E	978	867	793	765	787	797	814	816	817
SCE	973	861	784	750	778	789	802	805	808
SDGE	212	183	164	154	156	159	162	162	163
Total	2,164	1,911	1,741	1,669	1,720	1,745	1,778	1,783	1,788

Source: Database of State Incentives for Renewables & Efficiency

Table 4-2
California Demand Reduction Requirements (MW)

	2012	2013	2014	2015	2016	2017	2018	2019	2020
PG&E	253	237	228	241	257	258	270	270	269
SCE	215	199	189	193	213	215	222	222	223
SDGE	45	41	38	38	40	40	41	42	42
Total	513	477	455	472	510	514	533	533	534

Source: Database of State Incentives for Renewables & Efficiency

AB 2021 also requires that the energy reduction targets be met through incentive programs designed for utility customers. Energy saving resulting from state building code policies, appliance standards, and statewide market transformation efforts can also count toward meeting energy reduction targets (North Carolina State University, 2012).

Florida

As of June 2010, Florida had received a total of $935.5 million for selected DOE projects (U.S. Department of Energy, 2011). Of that $933.5 billion, $395.2 million has been allocated to grid modernization initiatives, primarily regarding Smart Grid Investment and Demonstration Projects ($261.6 million), State and Local Energy Assurance and Regulatory Assistance ($3.5 million), and Smart Grid Workforce Training ($5 million) (U.S. Department of Energy, 2011).

Distributed Generation & Net Metering

In March 2008, the Florida Public Service Commission (FLPSC) adopted HB 7135, 25-6.065, F.A.C. regarding net metering and interconnection for renewable-energy systems with up to two megawatts of capacity (North Carolina State University, 2011). HB 7135 applies to customers of investor-owned utilities who generate electricity using solar energy, geothermal energy, wind energy, biomass energy, ocean energy, hydrogen, waste heat or hydroelectric power. Although cooperative and municipal utilities are not required to provide net metering to customers, many have voluntarily adopted net metering policies (North Carolina State University, 2011).

Under the FLSPC rules, a customer’s net excess generation is carried forward as a credit to the customer's next bill at the utility's retail rate. At the end of a 12-month billing period, the utility then pays the customer for any remaining net excess generation at the utility's avoided-cost rate (North Carolina State University, 2011).

Investor-owned utilities are required to file annual reports with the FLPSC that detail distributed generation and net metering activities. Reports must include the number of customer-generators as well as data regarding the size, type and location of onsite systems, the aggregate capacity of net-metered generation, the amount of energy delivered to and generated from interconnected customers, and the total energy payments made to interconnected customers (North Carolina State University, 2011).

AMI Deployment Plans

Florida does not currently have a statewide policy regarding advanced metering infrastructure deployment plans.

AMI Data Privacy / Security

Florida does not currently have a policy addressing advanced metering infrastructure data privacy and security.

Energy Efficiency

In 1980, the Florida Energy Efficiency and Conservation Act (FEECA) was passed, requiring utilities with sales of more than 2,000 GWH to implement energy efficiency programs and begin conducting energy audits (U.S. Energy Information Administration, 2011). In 2008, FEECA was amended to include requirements to improve the efficiency generation, transmission, and distribution systems. In December 2009, the FLPSC reviewed numeric conservation goals; under Order No. PSC-09-0855-FOF-EG the FLPSC established the goal of 3.5 percent energy savings over ten years for electric utilities (North Carolina State University, 2011).

New York

In 2009, the New York State Smart Grid Consortium (NYSGC) was formed signifying the prioritization of smart grid implementation. NYSGC is a not-for-profit corporation that manages the collaborative development of the smart grid by fostering a strategic relationship between industry and academia. NYSGC believes that New York offers unique resources in that it serves as a nexus of electric energy research, is home to major industrial smart grid players, is a clean energy leader, and is the financial and media capital of the country (NYSGC, 2012).

As of June 2010, New York had received a total of $1.6 billion for selected DOE projects (U.S. Department of Energy, 2011). Of that $1.6 billion, $276 million has been allocated to grid modernization initiatives, primarily regarding Smart Grid Investment and Demonstration Projects ($267.8), State and Local Energy Assurance and Regulatory Assistance ($3.2 million), and Smart Grid Workforce Training ($5 million) (U.S. Department of Energy, 2011).

Distributed Generation & Net Metering

New York's original net metering law was enacted in 1997 and applied only to residential solar systems up to 10 kilowatts (North Carolina State University, 2012). After several amendments over the past twelve years, net metering is now available to all customer classes that are served by investor-owned utilities. Net metering is available on a first-come, first-served basis and is subject to technology, system size and aggregate capacity limitations. System capacity limits are as follows:

- Solar: 25 kW for residential, 2 MW for non-residential
- Wind: 25 kW for residential, 500 kW for farm-based, and 2 MW for non-residential
- Fuel Cells: 10 kW for residential, 1.5 MW for non-residential
- Micro-hydroelectric: 25 kW for residential, 2 MW for non-residential
- Biogas: 1 MW (farm-based only)
- Micro-CHP: 10 kW (residential only) (North Carolina State University, 2012)

For the majority of systems, customer net excess generation in a month is credited to the customer's bill for the following month at the utility's retail rate. The only exceptions are that net excess generation for residential solar, wind and farm-based biogas is reconciled annually at avoided-cost rate; and that net excess generation for micro-hydro, non-residential wind and solar, and residential micro-combined heat and power and fuel cells carries over indefinitely (North Carolina State University, 2012).

AMI Deployment Plans

The New York State Public Service Commission (NYPSC) has approved advanced metering infrastructure programs for residential customers. All meters and associated devices must be approved by the NYPSC prior to deployment and must meet the minimum functional requirements established under Case 09-M-0074. Utilities are only allowed to invest in AMI if there is a clear cost saving over current practices. Under Cases 09-E-0310 and 09-M-0074, utilities can recover costs associated with eligible Recovery Act funded projects through a surcharge passed onto ratepayers (U.S. Energy Information Administration, 2011).

AB 1656 was adopted in 2001; this established smart grid as a policy of the state, allowing two-way digital communication between electric utilities, their distribution grid, and customers (U.S. Energy Information Administration, 2011).

AMI Data Privacy / Security

New York does not currently have a policy addressing advanced metering infrastructure data privacy and security.

Energy Efficiency

New York has aggressively implemented multiple energy efficiency programs and incentives. In 2008, Under Cases 08-E1132 and 07-M-0548, the NYPSC set the goal of reducing electricity usage by 15 percent of forecast levels by the year 2015 (North Carolina State University, 2012). The NYPSC invited New York State Energy Research and Development Authority (NYSERDA) and the six large investor-owned electric utilities to submit electric energy efficiency program proposals and approved 45 energy efficiency programs in 2009 and 2010 (North Carolina State University, 2012).

Pennsylvania

As of June 2010, Pennsylvania had received a total of $807.9 million for selected DOE projects (U.S. Department of Energy, 2011). Of that $807.9 million, $243.8 million has been allocated to grid modernization initiatives, primarily regarding Smart Grid Investment and Demonstration Projects ($235.4), State and Local Energy

Assurance and Regulatory Assistance ($2.7 million), and Smart Grid Workforce Training ($5.7 million) (U.S. Department of Energy, 2011).

Distributed Generation & Net Metering

In 2006, the Pennsylvania Utilities Commission (PAPUC) adopted net-metering rules and interconnection standards.. In 2007, H.B. 1203 amended the Pennsylvania Alternative Energy Portfolio Standards (AEPS) Act of 2004 and increased eligibility requirements for participation. Revised rules consistent with these amendments were adopted by The PAPUC later adopted these amendments as well under PUC Omitted Rulemaking Order, Docket No. L-00050174 (U.S. Energy Information Administration, 2011).

Net metering is available to residential customers of investor-owned utilities that generate electricity with systems up to 50 kilowatts in capacity. Net metering is also available to nonresidential customers with systems up to three megawatts in capacity and customers with systems that have 3 to 5 MW of capacity who make their systems available to the grid during emergencies. Eligible technologies include, but are not limited to, solar-thermal energy, wind energy, hydropower, geothermal energy, biomass energy, fuel cells, combined heat and power, municipal solid waste, waste coal, and coal-mine methane (North Carolina State University, 2011).

In July 2011, the PAPUC issued a Tentative Order (Docket No. M-2011-2249441) requesting comments on the use of third-party ownership models (i.e., retail power purchase agreements) in combination with net metering. The Tentative Order proposes that third-party ownership models become eligible to participate in net metering, but that their production be limited to no more than 110 percent of onsite electricity needs.

As of this writing a formal determination on the issue has not been made (North Carolina State University, 2011).

AMI Deployment Plans

In October 2008, the Governor approved HB 2200, which requires smart grid meter deployment within the state. HB 220 required electric distribution companies (EDCs) to develop and submit a smart meter deployment plan to the PAPUC (Pietsch, 2011). A month later, Pennsylvania's Act 129 was passed. Act 129 mandates the development of statewide energy efficiency and conservation programs and the adoption of smart meter technology and time of use rates. Act 129 also requires that utility compliance be verified by an independent statewide evaluator using the total resources cost test (Pennsylvania Public Utility Commission, 2012).

AMI Data Privacy / Security

In 2011, the PAPUC issued a Tentative Order (Docket No. M-2009-209655) regarding the development of data exchange standards for smart meters. As of this writing a formal determination on the issue has not been made (U.S. Energy Information Administration, 2011).

Energy Efficiency

Act 129 created energy efficiency and conservation requirements for the state's investor owned utilities with at least 100,000 customers in the form of an Energy Efficiency Resource Standards (Pennsylvania Public Utility Commission, 2012). Pennsylvania's EERS requires obligated utilities to develop plans that will enable them to meet their targeted electricity savings of 1 percent by May 31, 2011 and 3 percent by May 31, 2013, measured against projected electricity consumption for the period from June 2009 – May 2010. The utilities must also develop plans that provide for peak demand savings of 4.5 percent by May 31, 2013, measured against actual peak demand from June 2007 – May 2008. The EERS allows for utility cost recovery through a reconcilable adjustment clause (North Carolina State University, 2012).

Texas

As of June 2010, Texas had received a total of $2 billion for selected DOE projects (U.S. Department of Energy, 2011). Of that $2 billion, $292.8 million has been allocated to grid modernization initiatives, primarily regarding Smart Grid Investment and Demonstration Projects ($282.7 million), State and Local Energy Assurance and Regulatory Assistance ($3.8 million), Smart Grid Workforce Training ($2.8 million) and Interconnection Transmission Planning and Analysis ($3.5 million) (U.S. Department of Energy, 2011).

Distributed Generation & Net Metering

Texas utilities have been offering distributed generation and net metering to customers since 1986. Substantive Rules, Section 23.66(f)(4) required that utilities offer a net metering option to onsite generation facilities with 50 kW of capacity or less. If customers want to participate in net metering, utilities must install and allow the meter to turn backward to register the customer's net energy consumption or production. Net consumption is billed at the retail rate outlined in the applicable rate schedule, and excess generation is purchased by utilities at the avoided cost (fuel cost only, no capacity component) (Public Utility Commission of Texas, 2011). Currently, there is not a statewide limit on the number of customers that can participate or total capacity under the net metering program.

In 1999, the State of Texas passed the Public Utility Regulatory Act (PURA). Among other rights, PURA granted customers the right to onsite distributed generation. The Public Utility Commission of Texas (PUCT) outlined the technical and procedural aspects of interconnecting distributed generation in Substantive Rules Â§25.211 and Â§25.212. The PUCT also developed a manual regarding the operational aspects and environmental treatment of distributed resources (Public Utility Commission of Texas, 2011).

The PUCT’s distributed generation manual was developed for use by utility engineers processing distributed generation interconnection applications. It was also written with customers who may be considering onsite distributed generation systems. The manual is comprehensive and addresses the issues that the PUCT believes to be the most important, including a dispute resolution process (Public Utility Commission of Texas, 2011).

Systems that are rated at one megawatt or more and that generate electricity that is not intended to be sold at wholesale are required to register as a self-generator. Systems that are intended to generate electricity that will be sold at wholesale, and the generating facility rated at one megawatt or more and does not own transmission or distribution facilities, must register as a power-generation company (Public Utility Commission of Texas, 2011).

AMI Deployment Plans

Texas does not have a policy regarding AMI deployment plans, but Texas-based companies such as Austin Energy, CenterPoint Energy, and Oncor have some of the largest AMI programs in the nation. For example, Austin Energy, the electricity provider for the city of Austin, Texas, began deployment of its smart grid program, “Smart Grid 1.0” in 2003. Smart Grid 1.0 services 1 million consumers and 43,000 businesses, covers 440 square miles, includes 500,000 devices, and involves 100 terabytes of data (Austin Energy, 2012). Austin Energy is already preparing “Smart Grid 2.0” for future implementation, but has not released an estimated deployment date yet.

AMI Data Privacy & Security

Texas does not currently have a policy addressing advanced metering infrastructure data privacy and security.

Energy Efficiency

In 1999, Texas enacted Texas Utilities Code §39.905 which required investor-owned utilities to meet 10 percent of their annual growth in electricity demand through energy efficiency. In 2011, Texas Utilities Code §9.905 was replaced by SB 1125 which requires a 20 percent reduction in annual growth in demand 2010 and 2011; 25 percent reduction in annual growth in demand 2012; and 30 percent reduction in annual growth in demand 2013 and beyond (North Carolina State University, 2011).

Discussion

As is illustrated in Table 4-3, distributed generation, net metering and energy efficiency policies have been adopted in all five states. Three states have adopted policies that support AMI deployment, while only one – California – has adopted AMI data security and privacy policies.

Table 4-3
Existing Legislative or Regulatory Activity by State

	Distributed Generation & Net Metering	AMI Deployment Plans	AMI Data Privacy/ Security	Energy Efficiency
California	X	X	X	X
Florida	X			X
New York	X	X		X
Pennsylvania	X	X		X
Texas	X			X

Distributed generation and net metering policies vary greatly regarding eligible technologies and maximum generating capacity of systems. Although all five states have adopted distributed generation and net metering policies, California, New York, Pennsylvania and Texas enacted their policies prior to adoption of the Energy Independence and Security Act. Florida enacted a distributed generation and net metering policy after the adoption of the Energy Independence and Security Act, but prior to the adoption of the American Recovery and Reinvestment Act. These policies align with the objectives of Section 1301, but are clearly not a result of states receiving Recovery Act funding.

California, New York and Pennsylvania have adopted advanced metering infrastructure deployment plans; Florida and Texas have not. Although California utilities began experimenting with advanced metering in 2003, advanced metering was not endorsed through legislative action until 2009. Similarly, the New York State Public Service Commission prioritized smart grid in 2001 and encouraged utilities to consider advanced meter deployment, but did not start requiring AMI deployment plans until 2009. Pennsylvania adopted Act 129 in 2008. AMI deployment policies for

California, New York and Pennsylvania align with the objectives of Section 1301, but are clearly not a result of states receiving Recovery Act funding.

Although Pennsylvania has proposed development of data exchange standards for smart meters, California is the only state that has passed legislation regarding AMI data privacy and security. California's policy, *CA EISA Adoption* was established as a direct response to the Energy Independence and Security Act. As such, it aligns with the objectives of Section 1301 and is considered to be a result of California pursuing Recovery Act funding.

All states included in this analysis had policies in the form of energy efficiency resource standards, but states varied in the type of reduction, the target amount, and deadline for meeting the EERS goal. All states were similar in that standards applied to primarily investor-owned utilities. States were also similar in that all of those included in this analysis began implementing energy efficiency policies prior to adoption of the Energy Independence and Security Act. These policies align with the objectives of Section 1301, but are clearly not a result of states receiving Recovery Act funding.

I was surprised to find that the majority of the states included in this analysis had adopted policies prior to 2009. I had expected states to adopt policies as a result of receiving Recovery Act funding for smart grid initiatives, but this doesn't appear to be the case in the states that I analyzed.

Policy Recommendation

Advanced metering infrastructure deployment is a crucial step in modernizing the grid, but this analysis finds that despite funding assistance through the Recovery Act, state-level AMI deployment and AMI data security and privacy policies have not been widely adopted. Although the Energy Independence and Security Act identifies advanced metering infrastructure as a characteristic of grid modernization, there is not a federal policy requiring advanced metering infrastructure deployment. Development of a national AMI deployment plan will shift the regulatory environment of the electric power grid from a fragmented model to a comprehensive one.

In order to be successfully implemented, a national AMI deployment plan would need to include data privacy and security standards, provide for utility costs recovery, and increase consumer awareness and engagement.

First, a national AMI deployment plan will need to address data security and privacy concerns. A national data privacy and security policy has not been adopted, but Congress directed the Federal Communications Commission to develop "a plan for the use of broadband infrastructure and services in advancing...energy independence and efficiency" (Federal Communications Commission, 2012). The National Broadband Plan is currently under development; the completed plan will address data privacy and security.

Next, a national AMI deployment plan will need to provide for utility cost recovery. State public utility commissions are currently responsible for approving local smart grid projects and cost recovery mechanisms for utilities. As such, AMI deployment levels varies greatly from state to state. Providing federal incentives and state-level cost recovery will help to alleviate the financial burden that utilities bear when they implement smart grid projects, which will increase deployment.

Consumer engagement and buy-in are vital to successful smart grid implementation whether we are assessing the success of an individual technology or of smart grid as a whole. The Electric Power Research Institute believes that consumers will inevitably bear the burden of smart grid transmission and distribution investments; over a 10-year period, residential and commercial customers will see an average annual increase of 8 to 12 percent in their monthly bill (Kassakian, Hogan, Schmalensee, & Jacoby, 2011). Pricing structures must be fair and just for both consumers and utilities to find value in the investment that smart grid implementation will require.

Utility customers undeniably care about cost, but they also care about reliability, customer service, and performance (Kassakian, Hogan, Schmalensee, & Jacoby, 2011). Successful implementation must include a measurable decrease in major power outages and interruptions as well as an increase in response to reliability issues when they occur. Smart grid must deliver on its promise to be proactive rather than reactive.

Section 5
CONCLUSIONS

Conclusions

In this study of state-level smart grid policy adoption, there was not a correlation between receiving Recovery Act funding and adopting policy. My research finds that although states analyzed have adopted policies that align with the objectives of Title XIII, Section 1301 of the Energy Independence and Security Act, policies were not adopted as a result of receiving funding. My study also finds that state policies do not adequately address advanced metering infrastructure deployment and associated data privacy and security standards.

Smart grid promises to facilitate a measurable increase in capacity for accommodating incremental renewable while increasing system efficiency and system reliability. It also promises to mitigate climate change through a reduction of greenhouse gas emissions, to enhance reliability by decreasing outages and to allow for quicker power restoration when an outage occurs.

Successful implementation of smart grid policies will require difficult changes in the regulatory environment, but these changes will lead to cleaner, more efficient electricity use. As we strive for a clean, sustainable energy future, we must look beyond the horizon of current generation technologies and focus on a more diverse, reliable, and interactive energy future.

Limitations of the Study

The primarily limitation of my study was my sample size. Although, the states that I included were representative of five different NERC regions, they only represented 10 percent of all states. Also, my study analyzed four of the ten objectives outlined by Title XIII, Section 1301 of the Energy Independence and Security Act.

Suggestions for Future Investigation

While my study only included data for five states, similar data exists for all states and the District of Columbia. This data could be used to revisit this analysis using a larger sample of states. My study only considered four of the ten objectives of Section 1301; this analysis could be revisited including all ten objectives. Using a larger sample of states and including all ten objectives could help to determine whether the policy is a cause or effect of Recovery Act funding. Revisiting the analysis could also help to determine whether states with policies already in place were more likely to receive funding than states without policies.

Section 6
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Appendix A
EISA TITLE XIII – SMART GRID SEC. 1301 – 1308, STATEMENT OF POLICY ON MODERNIZATION OF ELECTRICITY GRID

SEC. 1301. STATEMENT OF POLICY ON MODERNIZATION OF ELECTRICITY GRID.

It is the policy of the United States to support the modernization of the Nation's electricity transmission and distribution system to maintain a reliable and secure electricity infrastructure that can meet future demand growth and to achieve each of the following, which together characterize a Smart Grid:

(1) Increased use of digital information and controls technology to improve reliability, security, and efficiency of the electric grid.
(2) Dynamic optimization of grid operations and resources, with full cyber-security.
(3) Deployment and integration of distributed resources and generation, including renewable resources.
(4) Development and incorporation of demand response, demand-side resources, and energy-efficiency resources.
(5) Deployment of `smart' technologies (real-time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices) for metering, communications concerning grid operations and status, and distribution automation.
(6) Integration of `smart' appliances and consumer devices.
(7) Deployment and integration of advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air conditioning.
(8) Provision to consumers of timely information and control options.
(9) Development of standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid.
(10) Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services.

SEC. 1302. SMART GRID SYSTEM REPORT.

The Secretary, acting through the Assistant Secretary of the Office of Electricity Delivery and Energy Reliability (referred to in this section as the `OEDER') and through the Smart Grid Task Force established in section 1303, shall, after consulting with any interested individual or entity as appropriate, no later than 1 year after enactment, and every 2 years thereafter, report to Congress concerning the status of smart grid deployments nationwide and any regulatory or government barriers to continued deployment. The report shall provide the current status and prospects of smart grid development, including information on technology penetration, communications network capabilities, costs, and obstacles. It may include recommendations for State and Federal policies or actions helpful to facilitate the transition to a smart grid. To the extent appropriate, it should take a regional perspective. In preparing this report, the Secretary shall solicit advice and contributions from the Smart Grid Advisory Committee created in section 1303; from other involved Federal agencies including but not limited to the Federal Energy Regulatory Commission (`Commission'), the National Institute of Standards and Technology (`Institute'), and the Department of Homeland Security; and from other stakeholder groups not already represented on the Smart Grid Advisory Committee.

SEC. 1303. SMART GRID ADVISORY COMMITTEE AND SMART GRID TASK FORCE.

(a) Smart Grid Advisory Committee-

(1) ESTABLISHMENT- The Secretary shall establish, within 90 days of enactment of this Part, a Smart Grid Advisory Committee (either as an independent entity or as a designated sub-part of a larger advisory committee on electricity matters). The Smart Grid Advisory 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, to represent both private and non-Federal public sector stakeholders. One member shall be appointed by the Secretary to Chair the Smart Grid Advisory Committee.

(2) MISSION- The mission of the Smart Grid Advisory Committee shall be to advise the Secretary, the Assistant Secretary, and other relevant Federal officials concerning the development of smart grid technologies, the progress of a national transition to the use of smart-grid technologies and services, the evolution of widely-accepted technical and practical standards and protocols to allow interoperability and inter-communication among smart grid capable devices, and the optimum means of using Federal incentive authority to encourage such progress.

(3) APPLICABILITY OF FEDERAL ADVISORY COMMITTEE ACT- The Federal Advisory Committee Act (5 U.S.C. App.) shall apply to the Smart Grid Advisory Committee.

(b) Smart Grid Task Force-

(1) ESTABLISHMENT- The Assistant Secretary of the Office of Electricity Delivery and Energy Reliability shall establish, within 90 days of enactment of this Part, a Smart Grid Task Force composed of designated employees from the various divisions of that office who have responsibilities related to the transition to smart-grid technologies

and practices. The Assistant Secretary or his designee shall be identified as the Director of the Smart Grid Task Force. The Chairman of the Federal Energy Regulatory Commission and the Director of the National Institute of Standards and Technology shall each designate at least one employee to participate on the Smart Grid Task Force. Other members may come from other agencies at the invitation of the Assistant Secretary or the nomination of the head of such other agency. The Smart Grid Task Force shall, without disrupting the work of the Divisions or Offices from which its members are drawn, provide an identifiable Federal entity to embody the Federal role in the national transition toward development and use of smart grid technologies.

(2) MISSION- The mission of the Smart Grid Task Force shall be to insure awareness, coordination and integration of the diverse activities of the Office and elsewhere in the Federal Government related to smart-grid technologies and practices, including but not limited to: smart grid research and development; development of widely accepted smart grid standards and protocols; the relationship of smart-grid technologies and practices to electric utility regulation; the relationship of smart-grid technologies and practices to infrastructure development, system reliability and security; and the relationship of smart-grid technologies and practices to other facets of electricity supply, demand, transmission, distribution, and policy. The Smart Grid Task Force shall collaborate with the Smart Grid Advisory Committee and other Federal agencies and offices. The Smart Grid Task Force shall meet at the call of its Director as necessary to accomplish its mission.

(c) Authorization- There are authorized to be appropriated for the purposes of this section such sums as are necessary to the Secretary to support the operations of the Smart Grid Advisory Committee and Smart Grid Task Force for each of fiscal years 2008 through 2020.

SEC. 1304. SMART GRID TECHNOLOGY RESEARCH, DEVELOPMENT, AND DEMONSTRATION.

(a) Power Grid Digital Information Technology- The Secretary, in consultation with the Federal Energy Regulatory Commission and other appropriate agencies, electric utilities, the States, and other stakeholders, shall carry out a program--

(1) to develop advanced techniques for measuring peak load reductions and energy-efficiency savings from smart metering, demand response, distributed generation, and electricity storage systems;

(2) to investigate means for demand response, distributed generation, and storage to provide ancillary services;

(3) to conduct research to advance the use of wide-area measurement and control networks, including data mining, visualization, advanced

computing, and secure and dependable communications in a highly-distributed environment;
(4) to test new reliability technologies, including those concerning communications network capabilities, in a grid control room environment against a representative set of local outage and wide area blackout scenarios;
(5) to identify communications network capacity needed to implement advanced technologies.
(6) to investigate the feasibility of a transition to time-of-use and real-time electricity pricing;
(7) to develop algorithms for use in electric transmission system software applications;
(8) to promote the use of underutilized electricity generation capacity in any substitution of electricity for liquid fuels in the transportation system of the United States; and
(9) in consultation with the Federal Energy Regulatory Commission, to propose interconnection protocols to enable electric utilities to access electricity stored in vehicles to help meet peak demand loads.

(b) Smart Grid Regional Demonstration Initiative-

(1) IN GENERAL- The Secretary shall establish a smart grid regional demonstration initiative (referred to in this subsection as the `Initiative') composed of demonstration projects specifically focused on advanced technologies for use in power grid sensing, communications, analysis, and power flow control. The Secretary shall seek to leverage existing smart grid deployments.
(2) GOALS- The goals of the Initiative shall be--
(A) to demonstrate the potential benefits of concentrated investments in advanced grid technologies on a regional grid;
(B) to facilitate the commercial transition from the current power transmission and distribution system technologies to advanced technologies;
(C) to facilitate the integration of advanced technologies in existing electric networks to improve system performance, power flow control, and reliability;
(D) to demonstrate protocols and standards that allow for the measurement and validation of the energy savings and fossil fuel emission reductions associated with the installation and use of energy efficiency and demand response technologies and practices; and
(E) to investigate differences in each region and regulatory environment regarding best practices in implementing smart grid technologies.
(3) DEMONSTRATION PROJECTS-
(A) IN GENERAL- In carrying out the initiative, the Secretary shall carry out smart grid demonstration projects in up to 5

electricity control areas, including rural areas and at least 1 area in which the majority
of generation and transmission assets are controlled by a tax-exempt entity.

(B) COOPERATION- A demonstration project under subparagraph (A) shall be carried out in cooperation with the electric utility that owns the grid facilities in the electricity control area in which the demonstration project is carried out.

(C) FEDERAL SHARE OF COST OF TECHNOLOGY INVESTMENTS- The Secretary shall provide to an electric utility described in subparagraph (B) financial assistance for use in paying an amount equal to not more than 50 percent of the cost of qualifying advanced grid technology investments made by the electric utility to carry out a demonstration project.

INELIGIBILITY FOR GRANTS- No person or entity participating in any demonstration project conducted under this subsection shall be eligible for grants under section 1306 for otherwise qualifying investments made as part of that demonstration project.

(c) Authorization of Appropriations- There are authorized to be appropriated--

(1) to carry out subsection (a), such sums as are necessary for each of fiscal years 2008 through 2012; and

(2) to carry out subsection (b), $100,000,000 for each of fiscal years 2008 through 2012.

SEC. 1305. SMART GRID INTEROPERABILITY FRAMEWORK.

(a)Interoperability Framework- The Director of the National Institute of Standards and Technology shall have primary responsibility to coordinate the development of a framework that includes protocols and model standards for information management to achieve interoperability of smart grid devices and systems. Such protocols and standards shall further align policy, business, and technology approaches in a manner that would enable all electric resources, including demand-side resources, to contribute to an efficient, reliable electricity network. In developing such protocols and standards—

(1) the Director shall seek input and cooperation from the Commission, OEDER and its Smart Grid Task Force, the Smart Grid Advisory Committee, other relevant Federal and State agencies; and (2) the Director shall also solicit input and cooperation from private entities interested in such protocols and standards, including but not limited to the Gridwise Architecture Council, the International Electrical and Electronics Engineers, the National Electric Reliability Organization recognized by the Federal Energy Regulatory Commission, and National Electrical Manufacturer's Association.

(b) Scope of Framework- The framework developed under subsection (a) shall be flexible, uniform and technology neutral, including but not limited to technologies for managing smart grid information, and designed--

(1) to accommodate traditional, centralized generation and transmission resources and consumer distributed resources, including distributed generation, renewable generation, energy storage, energy efficiency, and demand response and enabling devices and systems;

(2) to be flexible to incorporate--

(A) regional and organizational differences; and

(B) technological innovations;

(3) to consider the use of voluntary uniform standards for certain classes of mass-produced electric appliances and equipment for homes and businesses that enable customers, at their election and consistent with applicable State and Federal laws, 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 by the appliances or equipment in response to an emergency or demand response signal, including through--

(A) load reduction to reduce total electrical demand;

(B) adjustment of load to provide grid ancillary services; and

(C) in the event of a reliability crisis that threatens an outage, short-term load shedding to help preserve the stability of the grid; and

(4) such voluntary standards should incorporate appropriate manufacturer lead time.

(c) Timing of Framework Development- The Institute shall begin work pursuant to this section within 60 days of enactment. The Institute shall provide and publish an initial report on progress toward recommended or consensus standards and protocols within 1 year after enactment, further reports at such times as developments warrant in the judgment of the Institute, and a final report when the Institute determines that the work is completed or that a Federal role is no longer necessary.

(d) Standards for Interoperability in Federal Jurisdiction- 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 of electric power, and regional and wholesale electricity markets.

(e) Authorization- There are authorized to be appropriated for the purposes of this section $5,000,000 to the Institute to support the activities required by this subsection for each of fiscal years 2008 through 2012.

SEC. 1306. FEDERAL MATCHING FUND FOR SMART GRID INVESTMENT COSTS.

(a) Matching Fund- The Secretary shall establish a Smart Grid Investment Matching Grant Program to provide reimbursement of one-fifth (20 percent) of qualifying Smart Grid investments.

(b) Qualifying Investments- Qualifying Smart Grid investments may include any of the following made on or after the date of enactment of this Act:

(1) In the case of appliances covered for purposes of establishing energy conservation standards under part B of title III of the Energy Policy and Conservation Act of 1975 (42 U.S.C. 6291 et seq.), the documented expenditures incurred by a manufacturer of such appliances associated with purchasing or designing, creating the ability to manufacture, and manufacturing and installing for one calendar year, internal devices that allow the appliance to engage in Smart Grid functions.

(2) In the case of specialized electricity-using equipment, including motors and drivers, installed in industrial or commercial applications, the documented expenditures incurred by its owner or its manufacturer of installing devices or modifying that equipment to engage in Smart Grid functions.

(3) In the case of transmission and distribution equipment fitted with monitoring and communications devices to enable smart grid functions, the documented expenditures incurred by the electric utility to purchase and install such monitoring and communications devices.

(4) In the case of metering devices, sensors, control devices, and other devices integrated with and attached to an electric utility system or retail distributor or marketer of electricity that are capable of engaging in Smart Grid functions, the documented expenditures incurred by the electric utility, distributor, or marketer and its customers to purchase and install such devices.

(5) In the case of software that enables devices or computers to engage in Smart Grid functions, the documented purchase costs of the software.

(6) In the case of entities that operate or coordinate operations of regional electric grids, the documented expenditures for purchasing and installing such equipment that allows Smart Grid functions to operate and be combined or coordinated among multiple electric utilities and between that region and other regions.

(7)In the case of persons or entities other than electric utilities owning and operating a distributed electricity generator, the documented expenditures of enabling that generator to be monitored, controlled, or otherwise integrated into grid operations and electricity flows on the grid utilizing Smart Grid functions.

(8) In the case of electric or hybrid-electric vehicles, the documented expenses for devices that allow the vehicle to engage in Smart Grid functions (but not the costs of electricity storage for the vehicle).

(9) The documented expenditures related to purchasing and implementing Smart Grid functions in such other cases as the Secretary shall identify. In making such grants, the Secretary shall seek to reward innovation and early adaptation, even if success is not complete, rather than deployment of proven and commercially viable technologies.

(c) Investments Not Included- Qualifying Smart Grid investments do not include any of the following:

(1) Investments or expenditures for Smart Grid technologies, devices, or equipment that are eligible for specific tax credits or deductions under the Internal Revenue Code, as amended.

(2) Expenditures for electricity generation, transmission, or distribution infrastructure or equipment not directly related to enabling Smart Grid functions.

(3) After the final date for State consideration of the Smart Grid Information Standard under section 1307 (paragraph (17) of section 111(d) of the Public Utility Regulatory Policies Act of 1978), an investment that is not in compliance with such standard.

(4) After the development and publication by the Institute of protocols and model standards for interoperability of smart grid devices and technologies, an investment that fails to incorporate any of such protocols or model standards.

(5) Expenditures for physical interconnection of generators or other devices to the grid except those that are directly related to enabling Smart Grid functions.

(6) Expenditures for ongoing salaries, benefits, or personnel costs not incurred in the initial installation, training, or startup of smart grid functions.

(7) Expenditures for travel, lodging, meals or other personal costs.

(8) Ongoing or routine operation, billing, customer relations, security, and maintenance expenditures.

(9) Such other expenditures that the Secretary determines not to be Qualifying Smart Grid Investments by reason of the lack of the ability to perform Smart Grid functions or lack of direct relationship to Smart Grid functions.

(d) Smart Grid Functions- The term `smart grid functions' means any of the following:

(1) The ability to develop, store, send and receive digital information concerning electricity use, costs, prices, time of use, nature of use, storage, or other information relevant to device, grid, or utility operations, to or from or by means of the electric utility system, through one or a combination of devices and technologies.

(2) The ability to develop, store, send and receive digital information concerning electricity use, costs, prices, time of use, nature of use, storage, or other information relevant to device, grid, or utility operations to or from a computer or other control device.

(3) The ability to measure or monitor electricity use as a function of time of day, power quality characteristics such as voltage level, current, cycles per second, or source or type of generation and to store, synthesize or report that information by digital means.
(4) The ability to sense and localize disruptions or changes in power flows on the grid and communicate such information instantaneously and automatically for purposes of enabling automatic protective responses to sustain reliability and security of grid operations.
(5) The ability to detect, prevent, communicate with regard to, respond to, or recover from system security threats, including cyber-security threats and terrorism, using digital information, media, and devices.
(6) The ability of any appliance or machine to respond to such signals, measurements, or communications automatically or in a manner programmed by its owner or operator without independent human intervention.
(7) The ability to use digital information to operate functionalities on the electric utility grid that were previously electro-mechanical or manual.
(8) The ability to use digital controls to manage and modify electricity demand, enable congestion management, assist in voltage control, provide operating reserves, and provide frequency regulation.
(9) Such other functions as the Secretary may identify as being necessary or useful to the operation of a Smart Grid.

(e) The Secretary shall--

(1) establish and publish in the Federal Register, within 1 year after the enactment of this Act procedures by which applicants who have made qualifying Smart Grid investments can seek and obtain reimbursement of one-fifth of their documented expenditures;
(2) establish procedures to ensure that there is no duplication or multiple reimbursement for the same investment or costs, that the reimbursement goes to the party making the actual expenditures for Qualifying Smart Grid Investments, and that the grants made have significant effect in encouraging and facilitating the development of a smart grid;
(3) maintain public records of reimbursements made, recipients, and qualifying Smart Grid investments which have received reimbursements;
(4) establish procedures to provide, in cases deemed by the Secretary to be warranted, advance payment of moneys up to the full amount of the projected eventual reimbursement, to creditworthy applicants whose ability to make Qualifying Smart Grid Investments may be hindered by lack of initial capital, in lieu of any later reimbursement for which that applicant qualifies, and subject to full return of the advance payment in the event that the Qualifying Smart Grid investment is not made; and

(5) have and exercise the discretion to deny grants for investments that do not qualify in the reasonable judgment of the Secretary.

(f) Authorization of Appropriations- There are authorized to be appropriated to the Secretary such sums as are necessary for the administration of this section and the grants to be made pursuant to this section for fiscal years 2008 through 2012.

SEC. 1307. STATE CONSIDERATION OF SMART GRID.

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

(16) CONSIDERATION OF SMART GRID INVESTMENTS-

(A) IN GENERAL- Each State shall consider requiring that, prior to undertaking investments in nonadvanced grid technologies, an electric utility of the State demonstrate to the State that the electric utility considered an investment in a qualified smart grid system based on appropriate factors, including--

(i) total costs;

(ii) cost-effectiveness;

(iii) improved reliability;

(iv) security;

(v) system performance; and

(vi) societal benefit.

(B) RATE RECOVERY- Each State shall consider authorizing each electric utility of the State to recover from ratepayers any capital, operating expenditure, or other costs of the electric utility relating to the deployment of a qualified smart grid system, including a reasonable rate of return on the capital expenditures of the electric utility for the deployment of the qualified smart grid system.

(C) OBSOLETE EQUIPMENT- Each State shall consider authorizing any electric utility or other party of the State to deploy a qualified smart grid system to recover in a timely manner the remaining book-value costs of any equipment rendered obsolete by the deployment of the qualified smart grid system, based on the remaining depreciable life of the obsolete equipment.

(17) SMART GRID INFORMATION-

(A) STANDARD- All electricity purchasers shall be provided direct access, in written or electronic machine-readable form as appropriate, to information from their electricity provider as provided in subparagraph

(B) INFORMATION- Information provided under this section, to the extent practicable, shall include:

(i) PRICES- Purchasers and other interested persons shall be provided with information on--

(I) time-based electricity prices in the wholesale electricity market; and

(II) time-based electricity retail prices or rates that are available to the purchasers.

(ii) USAGE- Purchasers shall be provided with the number of electricity units, expressed in kwh, purchased by them.

(iii) INTERVALS AND PROJECTIONS- Updates of information on prices and usage shall be offered on not less than a daily basis, shall include hourly price and use information, where available, and shall include a day-ahead projection of such price information to the extent available.

(iv) SOURCES- Purchasers and other interested persons shall be provided annually with written information on the sources of the power provided by the utility, to the extent it can be determined, by type of generation, including greenhouse gas emissions associated with each type of generation, for intervals during which such information is available on a cost-effective basis.

(C) ACCESS- 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. Information specific to any purchaser shall be provided solely to that purchaser.'.

(b) Compliance-

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

(6)(A) Not later than 1 year after the enactment of this paragraph, each State regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated utility shall commence the consideration referred to in section 111, or set a hearing date for consideration, with respect to the standards established by paragraphs (17) through (18) of section 111(d).

`(B) Not later than 2 years after the date of the enactment of this paragraph, each State regulatory authority (with respect to each electric utility for which it has ratemaking authority), and each nonregulated electric utility, shall complete the consideration, and shall make the determination, referred to in section 111 with respect to each standard established by paragraphs (17) through (18) of section 111(d).'.

(2) FAILURE TO COMPLY- Section 112(c) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2622(c)) is amended by adding the following at the end:

In the case of the standards established by paragraphs (16) through (19) of section 111(d), the reference contained in this subsection to the date of enactment of this Act shall be deemed to be a reference to the date of enactment of such paragraphs.'.

(3) PRIOR STATE ACTIONS- Section 112(d) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2622(d)) is amended by inserting `and paragraphs (17) through (18)' before `of section 111(d)'.

SEC. 1308. STUDY OF THE EFFECT OF PRIVATE WIRE LAWS ON THE DEVELOPMENT OF COMBINED HEAT AND POWER FACILITIES.

(a) Study-

(1) IN GENERAL- The Secretary, in consultation with the States and other appropriate entities, shall conduct a study of the laws (including regulations) affecting the siting of privately owned electric distribution wires on and across public rights-of-way.

(2) REQUIREMENTS- The study under paragraph (1) shall include--

(A) an evaluation of--

(i) the purposes of the laws; and

(ii) the effect the laws have on the development of combined heat and power facilities;

(B) a determination of whether a change in the laws would have any operating, reliability, cost, or other impacts on electric utilities and the customers of the electric utilities; and

(C) an assessment of--

(i) whether privately owned electric distribution wires would result in duplicative facilities; and

(ii) whether duplicative facilities are necessary or desirable.

(b) Report- Not later than 1 year after the date of enactment of this Act, the Secretary shall submit to Congress a report that describes the results of the study conducted under subsection (a).

SEC. 1309. DOE STUDY OF SECURITY ATTRIBUTES OF SMART GRID SYSTEMS.

(a) DOE Study- The Secretary shall, within 18 months after the date of enactment of this Act, submit a report to Congress 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 but not be limited to specific recommendations on each of the following:

(1) How smart grid systems can help in making the Nation's electricity system less vulnerable to disruptions due to intentional acts against the system.
(2) How smart grid systems can help in restoring the integrity of the Nation's electricity system subsequent to disruptions.
(3) How smart grid systems can facilitate nationwide, interoperable emergency communications and control of the Nation's electricity system during times of localized, regional, or nationwide emergency.
(4) What risks must be taken into account that smart grid systems may, if not carefully created and managed, create vulnerability to security threats of any sort, and how such risks may be mitigated.

(b) Consultation- The Secretary shall consult with other Federal agencies in the development of the report under this section, including but not limited to the Secretary of Homeland Security, the Federal Energy Regulatory Commission, and the Electric Reliability Organization certified by the Commission under section 215(c) of the Federal Power Act (16 U.S.C. 824o) as added by section 1211 of the Energy Policy Act of 2005 (Public Law 109-58; 119 Stat. 941)

Appendix B
TERMS

AC	Alternating current
AEPS	Alternative Energy Portfolio Standards
AMI	Advanced Metering Infrastructure
BLM	Bureau of Land Management
CPUC	California Public Utilities Commission
DC	Direct current
DOD	Department of Defense
DOE	Department of Energy
DSIRE	Database for State Incentives for Renewables and Efficiency
EDCs	Electric Distribution Companies
EERS	Energy Efficiency Resource Standard
EISA	Energy Independence and Security Act of 2007
EPA	Environmental Protection Agency
EPAct	Energy Policy Act of 1992
FEECA	Florida Energy Efficiency and Conservation Act
FERC	Federal Energy Regulatory Council
FLPSC	Florida Public Service Commission
GWh	Gigawatt-hour
ISO	Independent System Operators
kW	Kilowatt

kWh	Kilowatt-hour
LADWP	Los Angeles Department of Water and Power
MW	Megawatt
NERC	North American Electric Reliability Corporation
NYPSC	New York State Public Service Commission
NYSERDA	New York State Energy Research and Development Authority
NYSGC	New York State Smart Grid Consortium
PAPUC	Pennsylvania Utilities Commission
PUCT	Public Utility Commission of Texas
PUHCA	Public Utility Holding Company Act of 1935
PURA	Public Utility Regulatory Act
PURPA	Public Utility Regulatory Policies Act of 1978
PV	Photovoltaic
REA	Rural Electrification Act of 1936
RTO	Regional Transmission Organizations
SGDP	Smart Grid Demonstration Program
SGIG	Smart Grid Investment Grant