Survey of Smart Grid Implementation in New England

Including Opt Out Programs, the Importance of Consumer Education & an Early Look at Benefit Evaluation Approaches in Other States

New England States Committee on Electricity

Allison Smith

Spring 2012

TABLE OF CONTENTS

I. INTRODUCTION

Decisions about electric system planning and the adequacy of the New England's power resources - and the overall costs customers incur to ensure resource adequacy – may be directly influenced by whether and the extent to which customers shift their power use from peak periods to off-peak periods.[1] Smart grid technologies are one means to enable customers to do so.

Accordingly, the New England States Committee on Electricity (NESCOE) reviewed smart grid decisions by New England regulatory authorities and issues in some other states to share information primarily about customer-related issues that may arise if states elect to pursue smart grid technology deployment. NESCOE did not examine whether or under what conditions smart grid technology deployment makes economic sense; this paper does not offer a view on those or other threshold questions. Rather, this paper is limited to a review of smart grid-related activity in New England to date and focuses on customer education and opt-out programs that may inform states as they weigh whether or how to proceed with smart grid deployment following consideration of a host of complex issues. Because capturing the benefits of smart grid technology requires real change in how and when consumers use electricity and requires them to think about energy pricing, customer education will be a central element of smart meter programs and the realization of anticipated benefits.

"Smart grid" is a term used to cover a variety of new technologies such as sensors, software and communicating devices that relay information in real time about where and how customers are using electricity. Smart meters, in particular, enable customers *and* utilities to see how energy use and prices change in real-time and respond to those changes. The benefits of smart grid technologies differ for utilities and customers, but the ability to shift some energy use from peak to off-peak hours creates widespread

[1] In New England, on peak hours are from 7:00 a.m. through 11:00 p.m. on all non-holiday weekdays; off-peak hours are weekday hours between 11:00 p.m. and 7:00 a.m. and all day Saturdays, Sundays, and holidays.

benefits in the form of saved energy, capacity, and environmental emissions that occur with large fluctuations of energy demand. Reducing energy use during peak periods reduces the overall costs of the power system.

In 2007, Congress passed the federal Energy Independence and Security Act (EISA), with amendments to the Public Utility Regulatory Policies Act of 1978 (PURPA).[2] The new law urged each state public utility commission to consider, prior to making further investment in non-advanced grid technologies, requiring electric utilities to consider an investment in a Smart Grid system with respect to: (1) total cost, (2) cost-effectiveness, (3) improved reliability, (4) security, (5) system performance, and (6) societal benefit.

In 2007, New England state legislatures began passing energy efficiency legislation that often included smart meter implementation as a means to involve customers more directly with their energy demand. In response, some public utility commissions approved smart grid technologies and applications. Others began pilot programs.

This paper briefly reviews smart grid legislation in New England and summarizes smart grid funding made available to New England states by the U.S. Department of Energy. The balance of the paper provides practical information about: 1) educating consumers about smart grid; 2) experience with technology opt-out provisions; and, 3) program evaluation metrics based on experience in other jurisdictions. The paper is intended to share early state experience as New England states examine whether to implement smart grid programs or, in states where such programs are underway, whether and how to modify them overtime.

To summarize, the information provided here suggests that states, while considering issues related to deployment of smart gird technology, may wish to consider requiring utility smart meter program applications to include consumer education programs. States may also consider identifying, as appropriate, provisions to allow customers to elect *not* to take advantage of new smart meter technology. Finally, to some extent, the degree to

[2] 16 U.S.C. 2621(d)

which smart grid program benefits are fully realized may depend on customer participation. To that end, states may also wish to consider benefit evaluation metrics proposed by some utilities as they begin implementing smart meter programs.

II. SMART GRID IN NEW ENGLAND: STATE LAWS, FEDERAL FUND & REGULATORY DECISIONS

A. State Legislation

Over the past five years, each New England state has passed legislation regarding smart grid technologies as a means to achieve better energy efficiency. The table below briefly describes legislation related to smart meter technology in each New England state and briefly notes whether public utility commissions have issued related decisions.

Table I. New England State Legislation on Smart Grid

Connecticut	In June 2007, Connecticut's Governor signed the *Energy Efficiency Act of 2007*,[3] which required utilities to file Advanced Metering Infrastructure (AMI) plans and Time Of Use (TOU) rates with the Commission. Prior to this bill's passage, Connecticut Light & Power submitted an application to the Department of Public Utility Control (DPUC) to implement Time of Use (TOU), Interruptible Load Response, and Seasonal Use rates. The DPUC issued Order No. 7 in Docket No. 05-10-03 which required CL&P to file a smart meter plan to achieve the DPUC's objective to implement TOU rates for commercial & industrial customers and Connecticut's largest residential customers. The DPUC reopened the case in April 2007 for the purpose of reviewing the original plan. The DDPUC issued Order No. 4 after rehearing the case (Docket No. 05-10-03RE01), which required the states' utilities to run pilot programs and submit results to the commission by Dec. 1, 2009. In 2011 the CT Legislature created the Department of Energy and Environmental Protection (DEEP) under P.A. 11-80 and authorized DEEP to set energy policy prospectively. The DEEP then asked the Public Utilities Regulatory Authority (formerly the DPUC) to suspend the pending contested proceeding for smart meter program approval in order for the department to conduct and open, public process to allow the state to formulate the state's smart meter policy.[4]
Maine	In March of 2010, the *Act to Create Smart Grid Policy in the State* [5] established state smart grid policy to reduce greenhouse gas emissions and costs to consumers by providing them with more information about electric consumption. The bill declared a need for state policy on smart grid infrastructure. It allowed transmission and distribution utilities to recover reasonable costs incurred while implementing smart grid technologies. It also

[3] Energy Efficiency Act of 2007, Public Act 07-242/House Bill 7432
[4] CT PURA Docket No. 05-10-03RE04, Sept. 1, 2011 filing.
[5] Act to Create Smart Grid Policy in the State, Chapter 539 LD 1535

	directed the Public Utilities Commission (the Commission) to examine the need for a special entity in each utility's distribution territory to facilitate use of smart grid functions. The Commission previously approved smart metering programs for Bangor Hydro Electric and Central Maine Power companies earlier in 2010. In May of 2011 the Commission ordered CMP to implement an opt-out program under which customers could choose opt-out of smart meter functions for a fee.
Massachusetts	In 2008, Massachusetts passed the *Green Communities Act* (the Act), which contained a Smart Grid provision. Section 85 of the Act required each electric distribution company to file a proposed plan for a smart grid pilot program with the department of public utilities. The Act required a specific objective of the pilot program be to reduce peak and average loads by a minimum of 5 per cent for those customers participating in the pilot. Since 2009 the Department of Public Utilities has approved pilot programs for Unitil (D.P.U. 09-31) and NSTAR Electric (D.P.U. 09-33). A revised pilot program is currently pending before the Department for National Grid (D.P.U. 09-32; D.P.U. 11-129
New Hampshire	In July 2008, New Hampshire's Governor signed legislation, Senate Bill 451, authorizing rate recovery for utility investments in distributed energy resources. The purpose of the law was to stimulate public-utility investment in distributed energy resources, including demand response and other technologies intended to reduce line losses, support voltage regulation, or reduce peak load. In 2008, the Public Utilities Commission directed staff to create a working group to guide deployment of AMI and time-based rates. This group reported pilot studies underway by Public Service of New Hampshire (PSNH), National Grid, and Connecticut Light & Power (an affiliate of PSNH) at the end of 2008.[6] New Hampshire Electric Cooperative is also installing smart meters to its customers with funding it received from the American Recovery & Reconstruction Act.
Rhode Island	Rhode Island enacted legislation in 2009, which authorized electric and gas distribution companies within the state to propose and implement smart metering and smart grid demonstration projects, subject to the approval of the state's public utilities commission.[7] In May of 2009, the Public Utility Commission opened Docket No. 4052 to review Smart Grid. In July of 2009 National Grid filed a proposed pilot study for 10,000 customers as part of a multi-state pilot proposal to be pursued with federal funds. National Grid did not get the funds and the Procedural Schedule was suspended until further notice.[8]
	In March 2008, Vermont's Governor signed into law the *Energy Efficiency and Affordability Act of 2008*.[9] The law directed Vermont's Public Service Board (the Board) to "investigate opportunities for Vermont electric utilities to cost effectively install advanced 'smart' metering equipment

[6] Letter to Debra Howland, Re: Docket No. DE 06-061 Investigation into Energy Policy Act 2005 Standards. Report Regarding Advanced Metering Infrastructure and Time of Use Rates
[7] An Act…Public Utilities and Carriers – Renewable Energy Standard S. 485 and H. 5461
[8] RI PUC Docket No. 4075 http://www.ripuc.ri.gov/eventsactions/docket/4075page.html
[9] Energy Efficiency and Affordability Act of 2008, H 520

Vermont	capable of sending two-way signals and sufficient to support advanced time of use pricing during periods of critical peaks or hourly differentiated time of use pricing." Since then, the Board opened Docket 7307 to coordinate statewide policy regarding smart grid, such as development of principles regarding opt out, privacy and cyber security. Having received $69 million matching funds from an ARRA grant, major utilities have filed AMI plans with the Board to get approval for their smart grid projects.

B. American Recovery & Reinvestment Act Funds

In 2009, Congress, through the American Recovery and Reinvestment Act, allocated $4.5 billion to the U.S. Department of Energy to put toward efforts to modernize the electric power grid. Several New England states received significant ARRA funding. For example, Vermont received almost $69 million for its eEnergy Vermont project. eEnergy Vermont is a collaborative effort by Vermont's nineteen (19) electric utilities and its energy efficiency utility, Efficiency Vermont, designed to deploy advanced meters to 85% of customers in Vermont. The meters will eventually give customers the ability to lower their electricity usage by responding to financial incentives to shift their energy use to off-peak hours. In Maine, Central Maine Power received an award of nearly $96 million.

The table below lists all ARRA grants related to smart grid awarded in New England.[10]

Table II. ARRA Funds Awarded in New England

Project	States	Award Amount	Total Project Value
Connecticut Municipal Electric Energy Cooperative (Connecticut Municipal Electric Energy Cooperative Smart Grid Project)	Connecticut	$9,188,050	$18,376,100
ISO-New England (Synchrophasor Infrastructure and Data Utilization (SIDU) in the ISO New England Transmission Region)	Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont	$7,993,714	$18,087,427
Central Maine Power Company (CMP Advanced Metering Infrastructure Project)	Maine	$95,858,307	$191,716,614

[10] Recovery Act Smart Grid Programs, Project Information and Location

Vineyard Energy Project (Smart Grid Project)	Massachusetts	$787,250	$1,574,500
Town of Danvers, MA (Smart Grid Implementation Program)	Massachusetts	$8,476,800	$16,953,600
Premium Power (Distributed Energy Storage System)	Massachusetts	$6,062,552	$12,514,660
NSTAR Electric Company (Grid Self-Healing and Efficiency Expansion)	Massachusetts	$10,061,883	$20,123,766
NSTAR Electric and Gas Corporation (Urban Grid Monitoring and Renewables Integration)	Massachusetts	$5,267,592	$10,535,184
NSTAR Electric and Gas Corporation (Automated Meter Reading-Based Dynamic Pricing)	Massachusetts	$2,362,000	$4,877,989
National Grid USA Service Company	Massachusetts	$2,185,495	$4,370,990
Marblehead Municipal Light Department (Integrated AMI System with Real-Time Pricing Pilot Program)	Massachusetts	$1,346,175	$2,692,350
Honeywell International, Inc. (Full-Scale Implementation of Automated Demand Response)	Massachusetts	$11,384,363	$22,768,726
Beacon Power (20 MW Flywheel Frequency Regulation Plant)	Massachusetts	$24,063,978	$48,127,957
SustainX Inc. (Isothermal Compressed Air Energy Storage)	New Hampshire	$5,396,023	$10,792,045
New Hampshire Electric Cooperative, Inc. (Communications Systems Infrastructure/Automated Metering Infrastructure)	New Hampshire	$15,815,225	$35,144,946
Community College of Rhode Island	Rhode Island	$745,841	$910,841
Vermont Transco, LLC (eEnergy Vermont)	Vermont	$68,928,650	$137,857,302

ARRA funding, which has provided important stimulus in advancing smart grid deployment and understanding, is no longer available.[11] As such, going forward, states have the opportunity to learn from these pilots and deployments, and will have to analyze the costs and benefits of implementing such programs absent federal funds, assuming further federal funds are not forthcoming.

C. Regulatory Commission Orders

As noted, many state regulatory commissions across the country have issued decisions related to smart grid deployment. In August 2011, the Edison Electric Institute (EEI) prepared a useful Review of State Regulatory Review of Smart Grid Decisions.[12] Many

[11] U.S. Department of Energy, Recovery Act Selections for Smart Grid Investment Grant Awards – by State (Nov 2011), http://energy.gov/oe/downloads/recovery-act-selections-smart-grid-investment-grant-awards-state-updated-november-2011

[12] Edison Electric Institute, EEI Summary of State Regulatory Smart Grid Decisions (Aug. 2011),

New England states will continue to consider smart grid issues, either as a preliminary matter or as program modifications are warranted. To facilitate states' review of New England state regulatory decisions by state, issue or date, NESCOE used the EEI database to create a searchable file of New England smart grid decisions. It is attached as an Appendix.

SECTION II - SMART GRID IMPLEMENTATION: OPT OUT PROGRAMS & CONSUMER EDUCATION

Smart grid legislation passed by the New England states, and others, began each state on different paths to smart meter implementation. Accordingly, some programs are further along than others at this time. California and Maine, for example, implemented smart grid programs broadly while other states began with pilot programs.

In each of these cases, some customers concerned about the accuracy of the meters, potential privacy implications or the alleged impact on health of the technology responded negatively to the new technology. Some states saw widespread customer dissatisfaction, while in other states a relatively small percentage of dissatisfied customers voiced significant concern. For example, in California, 90,000 customers out of 9.7 million – or about 1% - signed up for "delayed installation". However, county-by-county, the percentage of customers who chose not to adopt the new smart meters ranges from 0.3% in some areas to 11.8% in others.[13] In response to some customer concerns, in California and Maine, public utility commissions required utilities to create an "opt-out" option to satisfy customers who did not want the technology in their homes. In both states, the opt-out program is still being implemented. The relative percentage of customers who will ultimately choose not to have smart grid technology is not yet known.

---

http://www.eei.org/whatwedo/PublicPolicyAdvocacy/StateRegulation/Documents/EEI_State_SG_Matrix_Update_Aug_2011.pdf.

[13] *State regulators to vote on PG&E smart meter "opt-out".* MercuryNews.com, Dana Hull, February 1, 2012

This customer reaction and subsequent regulatory action show that customer education is extremely important in order for consumers - and ultimately the overall power system - to actualize the potential benefits from smart meters. Customer education is a key component of both California's Smart Grid Deployment Plans, as required by the California Public Utility Commission (CPUC), and Central Maine Power's "opt-out" program, which was required by Maine Public Utilities Commission (MPUC). Vermont has also implemented an Opt Out program component.

A. Opt-Out Programs in Maine & California

After substantial proceedings in response to some customer complaints, the states of Maine and California created "Opt-Out" provisions for smart meter programs. The Maine and California programs allow customers who do not want smart meter technology in their homes to "opt-out" for a one-time charge and a recurring fee.

Elements of opt-out programs may include:

- The ability to turn off the new meter or retain the old meter
- A payment program to cover cost for this exception
- A method to recover costs that differ from anticipated levels of participation in the opt-out program.

Maine

The Maine Public Utility Commission (MPUC or the Commission) approved Advanced Metering Infrastructure (AMI) for Central Maine Power (CMP) in February of 2010.[14] Following the program approval, the Commission received five (5) formal complaints filed with ten (10) or more signers and a large number of letters from customers expressing their concerns regarding the smart meter program. According to Maine law (35-A M.R.S.A. Section 1302), the Commission has to investigate any written complaint made against a public utility by ten (10) persons aggrieved that rates or charges of a public utility are unreasonable or discriminatory. The first complaint, signers alleged the

[14]MPUC Order 2007-215, 2/25/2010.

Commission failed to consider the full range of health, security and safety issues associated with smart meters, which included issues related to the protection of medically sensitive individuals. Other complaints noted concerns with customer choice and the right to privacy. The Commission opened an investigation to address the five, ten-person complaints.[15] After substantial review of the complaints, the Commission ordered CMP to create an opt-out provision and to design a plan for customer education.[16]

CMP's Opt-Out program gives CMP customers the option to retain the analogue meter or to receive a new meter with the transmitter turned off. The option to retain the analogue meter comes with a one-time charge of $40 and a recurring monthly charge of $12 to allow CMP to recover the incremental costs associated with Opt-Out Program. The option to receive a new meter but operate it with the transmitter turned off is a one-time charge of $20.00 and a monthly charge of $10.50. Eligible LIHEAP customers may receive a discount on both charges. These charges would cover the cost of the Opt-Out Program. In its order, the Maine Commission stated that general utility ratemaking principal provides that utility customers who select non-standard service should pay the incremental costs for those services. The Commission concluded that because the smart meter is now standard service, customers who elect to opt-out are also electing to pay the incremental cost of non-standard service.[17]

In addition to establishing the customers' cost to Opt-Out, the Order required CMP to submit to the Commission for approval a communication plan that included Customer Outreach and Communication. The MPUC approved cost recovery from all ratepayers to support the cost of the outreach plan.

Maine's Customer Outreach requirements included:

- Calls to customers who indicate they do not want a smart meter;
- 30-day notice for customers to make a decision in advance; and,

[15] MPUC Docket numbers: 2010-345, 2010-389, 2010-398, 2010-400, 2011-085
[16] MPUC Order 2010-345, Part I 5/19/2011; Order 2010-345, Part II 6/22/2011.
[17] MPUC Order 2010-345, Part II 6/22/2011.

- A $25 charge to customers who elect to opt-out after a deadline in addition to opt-out charges.

Maine's Communication Plan requirements included:

- Program Description
- Potential benefits
- Opt-out options and meter modes
- Opt-out charges
- Existing meter relocation alternative
- The process to select an option

Because participation rates are difficult to predict, the Commission adopted a deferral and reconciliation mechanism to capture the difference in costs that may occur as a result of participation levels varying from the assumed number.

California

In California, some customers concerned about alleged health impacts and potential privacy and meter accuracy resisted installations of smart meters. Some customers met meter installation crews from Pacific Gas & Electric (PG&E) at their homes and turned them away, some appeared at commission meetings on a weekly basis to protest the meters, and others called their California Assembly representatives. In Santa Cruz and Marin counties where there were organized opposition groups, the number of customers asking to be on a "delayed installation" list increased to 11.8% and 6.2% of customers respectively.[18]

In 2010, California Bill A37 was introduced. It required utilities to give customers another option about smart grid deployment and to communicate the option to consumers. In response, Public Utility Commission President Peevey opened the Commission's March 10, 2011 business meeting with an announcement that PG&E would be directed to submit a proposal to allow customers who object to the wireless

[18] *State regulators to vote on PG&E smart meter "opt-out"*. MercuryNews.com, Dana Hull, February 1, 2012

devices the option of being metered without wireless technology, with the costs to be borne by the customers who choose to opt out.[19]

On March 24, 2011, PG&E submitted an application to the Commission that proposed to modify the SmartMeter™ program to enable residential customers to have PG&E turn off the radios in their gas and/or electric SmartMeters™. On February 1, 2012, Commission President Peevey issued a decision that directed PG&E to allow customers the option of retaining an analogue meter. Customers who elect this option will be charged $75 up front and $10 per month. Low-income customers will be charged $10 up front and $5 per month. These costs are interim in order to allow residential customers to begin selecting the opt-out option immediately. They may be adjusted at the conclusion of the second phase of the regulatory proceeding where issues concerning the actual costs associated with offering an analog alternative will be addressed.[20]

While there seemed to be general agreement that PG&E did not adequately communicate to customers the oncoming changes in advance of smart meter deployment, the Commission initially required each utility to describe how it would educate customers as part of their Smart Grid Deployment Plan. The Commission first required each utility to file a Smart Grid Deployment Plan pursuant to Senate Bill 17, which required such plans to meet the state's policy to "to modernize the state's electrical transmission and distribution system to maintain safe, reliable, efficient, and secure electrical service, with infrastructure that can meet future growth in demand."[21]

The Commission required each plan to include a Smart Grid Vision Statement, in which the utility was to describe how it would:

---

[19] PG&E Application for Approval of Modifications to its SmartMeter Program, (A1103014). Docketed materials can be accessed online in CPUC case A11-03-014

[20] CPUC Approves Analogue Meters for PG&E Customers Electing to Opt-Out of Smart Meter Service, Feb 01, 2012.

[21] CPUC Decision 10-06-47 Adopting Smart Grid Deployment Plans Pursuant to Senate Bill 17.

1. Enable customers to become more informed and to use electricity more efficiently to save money, and

2. Educate customers so that they can align their expectations with the realities of the technology.

The Commission indicated its intent to review these plans with great scrutiny in response to customer concerns in January 2012. The Commission said it would hold public workshops to examine the plans. It said the first workshop would review Smart Grid Deployment Plans from the perspective of a "Smart Customer" and will examine whether and how the deployment plans promote customer empowerment and engagement.

B. Opt Out Program in Vermont

In 2007, the Vermont Department of Public Service (DPS) requested that the Vermont Public Service Board (PSB or Board) open a generic smart grid investigation. That smart grid docket, 7307, has been and will remain open to deal with smart grid issues in the state as they arise. Broad opt-out principles submitted by DPS are currently pending Board action in Docket 7307. Both utilities and opponents of digital meters have actively participated in this proceeding. The DPS principles strongly support customers' ability to opt out of participation in the smart grid. However, to ensure that the decision to opt out does not negatively affect the majority of customers who fully participate in the smart grid, those who opt out should bear the cost of their decision. Each utility implementing smart grid is required to file a tariff regarding their opt-out policy for approval by the Public Service Board.

As a result, the five utilities that have filed AMI plans for Board approval have included their opt-out policies in those plans. Vermont's two largest electric utilities, Central Vermont Public Service (CVPS) and Green Mountain Power (GMP), have filed similar opt out tariffs. Both utilities found that the incremental cost of customers opting out necessitated a $10 per month charge, but will delay implementation of the fees until completion of meter installation in April 2013. Burlington Electric Department (BED) conducted cost-based studies that arrived at a $7.50 monthly fee, and will delay its fee implementation until January 2013. The DPS will conduct further review of the cost

basis behind any opt out fees prior to implementation in 2013. Stowe Electric Department (SED) and Washington Electric Cooperative (WEC) do not plan to charge opt-out fees. WEC will offer an additional "functional" opt out, in which customers could elect to only have meters transmit data once a month over WEC's power line carrier communication system. For those utilities that will charge opt out fees, there will be no upfront cost and customers will not be charged for smart meter installations later if they decide to reverse their opt out decision[22].

C. Customer Education: Strategic Smart Meter Implementation

In Maine and California, some customers' response to smart meter deployment triggered the issue of customers having the option not to have a smart meter and for further customer education. Educating customers in advance of deploying smart meters could potentially help to prevent some negative customer response. Research shows that commissions and utilities can use certain strategies to avoid setbacks in their efforts to improve energy efficiency with smart meters.[23] They include: knowing the customer; communicating effectively; enabling customer response; and, educating customers in advance.

1. Know the Consumer

Smart meters introduce new and unfamiliar technology into homes and ask customers to approach energy use in a dramatically different way. Some customers will adapt to this technology quickly and manage energy consumption for a variety of reasons, while some will strongly resist change. In a study of how people perceive smart meter technology, the Smart Grid Consumer Collaborative found that, "cost consciousness, green altruism, tech enthusiasm, indifference, and resistance…persist across cultures, income levels, and education while the percentage mix varies locally."[24]

---

[22] The Vermont Legislature is considering action on smart grid related to opt out. Any bills from the legislature are expected to be consistent with the DPS position.
[23] *2011 State of the Consumer Report. January 31, 2011,* Smart Grid Consumer Collaborative.
[24] Id.

In a study of what motivates consumers to interact with the new smart meters, researchers found that the key to creating engagement lies in understanding the kinds of behaviors that different types of customers will undertake.[25] A number of people choose to participate in smart meter programs for various reasons: some are motivated to save energy for environmental reasons and some for personal financial reasons. Researchers found that marketing the new technology to people based on their attitudes about money and environment will lead to greater adaptation.

2. Communicate Effectively

Utilities and Commissions can manage customer expectations by introducing smart meters in advance of deploying them. It is important to communicate changes to both *when and how* their electric metering and billing will change to get customers on board before the changes take place.

For example, National Grid held a public summit in Worcester, Massachusetts to engage residents in planning and design of their smart grid pilot program. National Grid is working with customers to develop an effective marketing strategy and to determine how to communicate effectively in hopes that the effort will encourage participation.[26]

The Washington, D.C. area utility, Potomac Electric Power Co. (PEPCO), undertook market research studies with the goal of assessing customer understanding of its messaging and educational campaigns. The studies were part of a larger customer education and communications plan, which the Maryland Public Service Commission required prior to approving PEPCO's Phase I implementation of advanced metering infrastructure.[27] The studies included: 1.) a Tracking Study to track customer awareness and perceptions of smart meters; 2.) Focus Groups to assess reactions to messaging and pricing options; 3.) a Segmentation Study to identify appropriate messaging for different

---

[25] *2011 Smart Energy Consumer Behavioral Segmentation Study*, Peter Shaw, J.D. Power & Associates

[26] Effective Customer Communication for Smart Tariff, Metering Programs.

[27] MD PSC Case No. 9207, Order No. 83571

customers; and 4.) a Customer Insight Panel to get direct feedback across a range of topics.[28]

3. Enable Customer Response

Programs designed to help customers save money speak to everyone, but different customer segments will have different abilities to respond to prices. Successful smart grid plans have programs designed to meet the various needs of specific customer segments.

For example, Pacific Gas & Electric (PG&E) customers can sign up for the SmartRate program. The utility will notify customers of higher prices on peak SmartDays between 2:00 p.m. and 7:00 p.m. Though rates are high at this time, discounted rates apply at all other times during the summer season, from May through October. The program is limited to no more than 15 SmartDays™. Alternatively, PG&E has an optional Time-Of-Use rate schedule for individually metered customers who can minimize their loads during defined time periods.[29]

4. Educate Customers in Advance

Proposals for smart meter programs in Maryland have garnered national attention and have elevated consumer concerns in discussions about smart meters. The Maryland Public Utility Commission (Commission) initially denied a smart meter application from Baltimore Gas & Electric (BG&E), calling the business case for it's initial proposal "untenable". A primary tenant of that proposal relied on mandatory Time of Use rates. In denying the application, the Commission asserted that BG&E's proposal relied on a fundamental change in how BG&E customers use electricity and think about energy pricing, yet it did not specify how BG&E would educate customers to bring about that change.[30] In that order, the Commission required that a detailed Customer Education plan had to be approved by the Commission before BG&E could implement any advanced metering system.

---

[28] Smart Grid Customer Education Symposium, October 2011. Market Research Surveys and Studies, Denise Senecal, PEPCO.
[29] PG&E Rate Options
[30] MD PSC Order 83410, 6/22/2010, pg. 31

At the Commission's direction, the Smart Grid Implementation working group formed to design a plan to educate customers about smart meters. The working group consisted of the commission's technical staff, Potomac Electric Power Company, the Office of People's Counsel, the Maryland Energy Administration, Montgomery County Office of Consumer Protection, AARP and BG&E. BG&E filed a plan for customer education and communication, designed on a consensus basis from these meetings.[31]

The Commission approved BG&E's revised proposal, which: 1.) did not require mandatory Time of Use pricing; 2.) included a Consumer Education and Communication Plan; and, 3) adopted measures to mitigate risk to ratepayers.[32] The Commission noted the importance of customer education in the order, saying:

> "We cannot emphasize this strongly enough: the success of this Initiative, and the likelihood that customers will actually see the benefits of this project, depend centrally on the success of the Company's customer education and communication effort."[33]

IV. EVALUATING SMART GRID BENEFITS

The expected customer and system benefits of smart grid deployment may turn in part on whether and the extent to which customers take advantage of the technology. As states evaluate utility smart grid proposals, states may wish to consider benefit evaluation metrics utilities in other jurisdictions have proposed.

The Maryland Public Utilities Commission (the Commission) identified a key aspect of smart meter programs in its decision denying BG&E's first Advanced Metering Infrastructure (AMI) proposal, described above: To what extent do smart grid program

[31] MD PSC Case 9208, BG&E Customer education plan (documents 96, 97, 103, and 104).
[32] MD PSC Case No. 9208, Order No. 83531, pp. 10-12.
[33] MD PSC Case No. 9208, Order No. 83531, pg. 43, 8/13/2010.

benefits depend on customer participation in dynamic pricing programs? In Maryland, the Commission denied BG&E's application because benefits depended almost entirely on mandating customers to participate in Time of Use pricing.[34]

To some extent, many benefits from smart meter programs flow from customers choosing not to use high-electric demand devices or appliances when electric prices increase substantially during peak periods. Assessing the benefits of smart meters from the *utility's* perspective can provide a commission insight into the level of customer acceptance and use, which are necessary for smart grid program benefits to out-weigh the costs. To increase the likelihood of achieving smart grid program benefits, the California and Maryland Commissions required utilities to file customer education plans *and* plans that estimate program benefits.

A. Maryland

In Maryland, the Commission required both BG&E and Pepco to file a comprehensive set of metrics for all aspects of the companies' smart meter proposals. The metrics included:

1. Installation and Performance of the technology
2. Incremental costs incurred
3. Incremental benefits realized
4. Effectiveness of consumer education & communication efforts, and
5. Customer privacy & cyber-security

The companies were required to report to the Commission their performance against the metrics and appear before the Commission for periodic reviews. This allowed the Commission to monitor the companies' progress toward their stated goals in the smart meter proposals.[35]

[34] MD PSC Case No. 9208 Order No. 83410.
[35] MD PSC Case Nos. 9208 and 9207, Order No. 83571 pg. 5.

In Maryland, a Smart Grid Implementation Working Group designed both consumer education plans and reporting metrics on a consensus basis. The Working Group determined metrics for reporting and submitted "*Advanced Metering Infrastructure Performance Metrics Reporting Plans*" to the Commission as required.[36] The Plans called for two-phases. Phase I metrics would capture: 1.) data related to costs, 2.) project delivery and installation, and 3.) initial impacts on utility operations and related activities that occur during the deployment phase. Phase II metrics would seek to measure the realization of benefits associated with implementation of new AMI functionalities, such as outage management, customer service, continued implementation of operational efficiencies relating to remote connection and disconnection of meters and meter reading, presentation of web-based information to customers, and dynamic pricing activities.

The Phase I Financial Cost/Benefit metrics fell under five metric categories:

1. Project Costs
2. Capital Savings (direct & avoided)
3. O&M Savings (direct & avoided)
4. Other Economic Benefits (reduced energy theft, DOE grant payments)
5. Reporting of Wholesale Market Capacity Market actions that will impact future Dynamic Pricing Benefits.

Phase II metrics were not yet solidified at the time of filing of this first report.[37] Initial metrics identified for Phase II at the time of filing included:

AMI Metrics Section	**Performance Metric Category**
Financial Cost/Benefits	O&M Savings (direct & avoided)
Financial Cost/Benefits	Capital Savings (direct & avoided)
Financial Cost/Benefits	Dynamic Pricing Benefits
Financial Cost/Benefits	Other Economic Benefits
Operational	Field Visits
Operational	Number of remote connects / disconnects
Operational	Billing Accuracy
Operational	Reliability

[36] MD PSC Case Nos. 9208 and 9207, 5/18/2011.
[37] Id.

Communications & Education	Customer Engagement
Communications & Education	Customer Satisfaction
Communications & Education	Dynamic Pricing Engagement
Communications & Education	Inquiries

B. California

In California, Section 8367 of the Public Utilities Code requires the Public Utilities Commission to file an initial annual report to the California Legislature about smart grid deployments in California. The California Public Utilities Commission (the Commission) required utilities to file Smart Grid Deployment Plans,[38] which were to include eight elements:

1. Smart Grid Vision Statement
2. Deployment Baseline
3. Smart Grid Strategy
4. Grid Security and Cyber Security Strategy
5. Smart Grid Roadmap
6. Cost Estimates
7. Benefits Estimates Metrics

The Commission did not specify what metrics would be used to assess benefits. Rather, the Commission directed utilities to assess:

1. How the identified benefits achieve policy requirements,
2. Benefits beyond simple compliance with the regulatory requirement, called economic benefits, and,
3. Other benefits such as reliability and safety, which are difficult to quantify

The Commission staff requested that investor owned utilities prepare a report on Consensus and Non-Consensus metrics to help the state evaluate the development of smart grid in California. The exact nature of smart grid investments, projects and programs will be further defined in the future (and may differ from current expectations). As such, future developments will require the Commission, the investor owned utilities and other stakeholders to revisit the consensus metrics they previously identified.

[38] CPUC Order D10-06-047 Decision Adopting Requirements for Smart Grid Deployment Plans Pursuant to Senate Bill 17.

California's investor owned utilities first submitted the "Report on Consensus and Non-Consensus Smart Grid Metrics" to the Commission in December 2010. In July 2011, California approved Smart Grid Deployment Plans. Because smart grid program benefits were prospective at that time, the initial benefits were estimated in a variety of formats.

California law requires Annual Reports to be submitted after utilities submit initial their Deployment Plans. In the Consensus Metrics report the utilities submitted to the Commission, the investor owned utilities requested that the Commission direct them to continue refining consensus metrics, so that they could share additional information with parties pertaining to data that can be collected and specific planned deployments. Participants noted that the workshops would help to identify specific metrics as they become feasible and further guide the IOUs as they make smart grid investments.[39]

Pacific Gas & Electric Benefits Estimate

Pacifica Gas & Electric's (PG&E) Smart Grid strategy focused on developing capabilities that most effectively respond to the Smart Grid strategic drivers: 1.) customer empowerment; 2.) safety, reliability and security; 3.) environmental sustainability; 4.) flourishing and efficient energy markets; and 4.) consumer technological advancement. The benefits identified are both quantifiable and qualitative. Some benefits can be monetized or directly valued in dollars. Others are driven by policies to achieve societal or indirect values, such as system reliability improvements and greenhouse gas emission reductions.[40] PG&E used the benefits framework defined by the Electric Power Research Institute (EPRI) - "Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects" - to assess these benefits.

The quantifiable benefits from the proposed Smart Grid projects fell into the following general categories: 1.) avoided energy procurement costs, 2.) avoided transmission and distribution capital investment, 3.) avoided operations and maintenance costs, 4.) reliability improvements and 5.) environmental improvements.

---

[39] Report on Consensus and Non-Consensus Metrics, Dec 29, 2010. Pg 8.
[40] PG&E Smart Grid Deployment Plan, page 167

For benefits that can be directly valued in dollars, PG&E used public source estimates such as E3's Avoided Capacity and Energy values[41]. These are often used to estimate the benefits of energy efficiency programs. Project benefits were assigned over an estimated average project life of 20-years accounting for variability in asset life across different components, such as software (short-lived) and energy infrastructure capital (long-lived).

PG&E developed conceptual and provisional estimates of the following benefits:

1. Avoided Energy Procurement Costs
    a. Avoided Generating Capacity
    b. Avoided Energy Procurement
    c. Avoided Ancillary Services Procurement
2. Avoided or Deferred Transmission & Distribution Capital Investment
3. Avoided Operations & Maintenance Costs
4. Reliability Improvements
5. Environmental Benefits
    a. Priority Pollutant Reductions
    b. Greenhouse Gas Emission Reductions

[41] E3's Avoided Cost Calculator calculates the value of capacity during peak energy. It is generally used to represent the value of energy efficiency, the value of energy NOT used at peak. E3 uses a combustion turbine as the proxy resource for capacity. The value of capacity is calculated as the capacity residual: the real annualized cost of a new CT less the annual net revenues that generator could earn through participation in the real-time energy and ancillary services markets. Each of those components is calculated individually in the avoided cost model, which may be downloaded at this link.

Table III (7-6): PG&E Incremental Smart Grid Project Portfolio Benefit Estimate

Benefits	Nominal Value ($MM)	Key Variables
Avoided O&M Costs	$140 - $195	• Projected efficiency improvements • Internal labor estimates • Incremental investment in Substation Equipment avoided (and PG&E specific value) • Energy capacity supplied by project • E3 Values for Avoided Distribution Capacity[7]
Avoided Transmission & Distribution Capital Investment	$240 - $360	
Avoided Energy Procurement Cost	$600 - $1,400	
Avoided Capacity Cost	*$75 - $330*	• Avoided Incremental Generating Capacity • E3 Values for Avoided Generation Capacity
Avoided Energy Cost	*$500 - $1,040*	• Avoided Energy • E3 Values for Avoided Capacity • Avoided Peak and Real Time Procurement
Avoided Ancillary Services Cost	*$20 - $30*	• Avoided Energy • E3 Values for Ancillary Services
Total Accumulative Benefits	$975 - 1,955	

For specific breakouts of quantifiable Avoided Cost benefit estimates, see Tables 7-8 through 7-12 in the PG&E Smart Grid Deployment Plan.[42]

Variables such as utility project execution and natural gas prices affect benefit estimates. As discussed above, the extent to which customer benefits are captured depends largely on customer adoption rates, public education and outreach campaigns. Customer Outreach and Education programs support the Smart Grid strategy by enabling customers to attain the benefits from the set of projects within the 'Engaged Consumers' program area.[43] These projects support the attainment of explicit and implicit policy mandates such as integrating customer loads into wholesale energy markets and empowering customers by providing richer data directly to the customer or indirectly to a third party energy service provider.

San Diego Gas & Electric Benefits Estimates

San Diego Gas & Electric (SDG&E) chose to estimate the benefits of smart grid from the

[42] PG&E Smart Grid Deployment Plan, page 176-180.
[43] Ib, page 182

societal perspective. This focuses on efficiency in producing and delivering energy and environmental quality improvement. This type of benefit evaluation is used to determine the cost effectiveness of energy efficiency programs, storage as it relates to the effective integration of more renewable resources, reduced air emissions from generation, and improved utilization of grid assets (i.e., generation and transmission and distribution equipment).[44]

SDG&E also asserts that using the societal benefits test avoids pre-determining the number of customers that will engage with smart meters and the level of their engagement. The societal benefits test accounts for far-reaching and often hard-to-measure benefits.

This approach was meant to leverage benefit categories defined by the Electric Power Research Institute (EPRI):

- **Economic:** including avoided or reduced costs and investments due to improved system efficiency or asset utilization
- **Reliability:** including avoided or reduced electric service interruptions and improvements in power quality and reliability benefits to customers that are determined through value of service studies
- **Environmental**: including avoided or reduced emissions, which impact climate change and adversely impact human health and various ecosystems
- **Other**: including improvements to cyber security, worker/customer safety, customer satisfaction as well as reduced dependence on oil.

The following chart outlines SDG&E's assessment of EPRI's benefit categories.

Table IV. SDG&E Benefits Framework

SDG&E Benefits Framework	
Category	Benefit Type
Economic	Improved Asset Utilization

[44] SDG&E Smart Grid Deployment Plan, page 286

	Transmission & Distribution Capital Savings Transmission & Distribution Operating Expenses Savings Theft Reduction Energy Efficiency Electricity Cost Savings
Reliability	Power Interruptions Power Quality
Environmental	Air Emissions
Other	Security & Safety Customer Satisfaction Energy Independence

Southern California Electric Benefits Estimate

Southern California Electric (SCE) estimated benefits within the categories prescribed by the California Public Utilities Commission (D.10-06-47) as follows:

1. How the identified benefits achieve policy requirements,
2. Benefits beyond simple compliance with the regulatory requirement (economic benefits),
3. Other benefits such as reliability and safety, which are difficult to quantify

SCE estimates benefits from customer participation in demand response and plug-in electric vehicle integration, in the following categories:

1. Meeting Public Policy Requirements: SCE identified several public policy goals the smart meter installation will help to enable, namely: demand response and time-of-use pricing, customer access to smart meter usage on a real-time basis, customer data security, decreased energy consumption from load management, and plug-in electric vehicle integration.

2. Economic Benefits: SCE anticipates economic benefits to flow from customers' adaptation of smart meters and energy management devices. This technology will allow customers to see meaningful electricity use and price information such as: [45]

[45] SCE Smart Grid Deployment Plan, page 130

- Peak Demand Reduction & Avoided Costs Enabled by Demand Response
- Energy Savings Obtained through Enhanced Conservation
- Reduced System Costs & Improved Utilization of Distribution Assets from electric vehicle integration

3. Other Benefits: In this category, SCE lists increased system reliability and enhanced customer satisfaction.

SCE estimates addition benefits to flow from improvements to its system. These benefits include Distribution and Substation Automation, Transmission Automation, and Asset Management.

The material discussed here assesses the current status of various matters. The issues and resolution to them will continue to unfold over months and years ahead. For example, the benefit assessments described here were *preliminary* filings in response to the California Public Utility Commission's current requirements. Each utility will continue to develop metrics to assess costs and benefits related to smart grid deployment. Further developments will occur in the California Public Utilities Commission Proceeding number A1106006.

V. CONCLUSION

Smart grid benefits - including overall system cost reductions that will ultimately flow to customers - are likely to be many. As noted, NESCOE has not examined whether or under what conditions smart grid technology deployment makes economic sense. In most cases, benefits will flow to customers who adapt to new metering devices and shift electricity use, particularly at peak periods. Because adaptation requires real change in how and when consumers use electricity and requires them to think about energy pricing, customer education will be a central element of smart meter programs and the realization of anticipated benefits. As states begin or modify smart grid programs, they may wish to consider collecting consumer participation data to enable them to track and evaluate benefits, which may illuminate the degree of customer adaptation and further customer

education efforts that may be helpful.

NESCOE appreciates contributions and reviews from smart grid experts in various offices within New England state governments in preparing this paper.