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Investigation into Needs and Standards for a Maine Smart Grid Coordinator

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National Regulatory Research Institute

Consultant Report for Maine PUC Docket 2010-267: Smart Grid Coordination

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Executive Summary

The purpose of this report is to summarize and analyze the information provided in Maine's smart grid coordinator investigation and to make recommendations that follow from that analysis. While this report is based on the Maine investigation and Maine's specific energy industry structure (which includes both regulated and competitive market participants), the author hopes the insights provided will be useful to all states implementing smart grid technologies.

Maine PUC Docket No. 2010-267 is an investigation, on the Commission's own motion, captioned *Maine Public Utilities Commission Investigation into Need for Smart Grid Coordinator and Smart Grid Coordinator Standards*. This Docket was initiated in response to Maine legislation, *An Act to Create a Smart Grid Policy in the State* ("*Smart Grid Policy Act*") (P.L. 2010 Ch. 539, codified at 35-A M.R.S.A. § 3143 (2010)).

The *Smart Grid Policy Act* directs the Maine Public Utilities Commission ("Commission") to investigate the possibility of creating a smart grid coordinator. A smart grid coordinator is defined as an entity "that manages access to smart grid functions and associated infrastructure, technology and applications within the service territory of a transmission and distribution utility" (35-A M.R.S.A. § 3143(1)(B)). The Commission is to determine whether creating one or more smart grid coordinators is in the public interest, and if so, to adopt smart grid coordinator standards (35-A M.R.S.A. § 3143(5)).

Maine's Commission is presented with these questions:

1. Is the combination of entities that comprise the existing energy market structure sufficient to maximize the potential benefits that could be achieved through smart grid deployment and operations?

2. Will additional or different regulatory incentives and performance objectives be required to lead the existing industry structure to maximize smart grid benefits? If yes, what changes are required?

3. Will the creation of a new entity, presently known as a Smart Grid Coordinator, improve upon the status quo? If yes, how and why?

If the third question is answered in the affirmative, then the Commission will have to consider – in a Phase 2 of Docket No. 2010-267 – the functions to be assigned to a smart grid coordinator, and how that new entity (or entities) will be selected and monitored.

Eleven parties intervened in Docket No. 2010-267. The parties, in order of appearance, include Maine's Office of the Public Advocate (OPA), Environment Northeast, Central Maine Power (CMP), Grid Solar, Thermal Energy Storage of Maine (TESM), the University of Maine's Smart Grid Center, Bangor Hydro-electric Company (BHE), the Maine Renewable Energy Association (MREA), the Industrial Energy Consumer Group (IECG), the Conservation Law Foundation (CLF), and Efficiency Maine Trust (EMT).

The parties were asked to describe each smart grid technology and system and its intended function, and explain how it achieves its intended purpose. For future smart grid technologies, parties were asked to address what each technology does and to describe the technology's commercial availability and viability. For applications at the bulk power and Maine local T&D system levels, parties were asked to explain the planning and decision-making process by which the technology or system would be considered. The parties were also asked to:

> Describe operational and/or institutional changes, e.g., smart grid coordinator, that would enhance the value of the technology or system. In particular, describe the specific roles of a smart grid coordinator in planning and operating the systems in Maine. How would coordination with other system operators, e.g., ISO, be assured? What would a smart grid coordinator's status be with respect to FERC [Federal Energy Regulatory Commission], NERC [North American Electric Reliability Corporation], or other federal jurisdiction? State jurisdiction? Identify the strengths and weaknesses of having a smart grid coordinator perform these functions rather than the utilities and/or ISO. Identify additional costs that would be caused by having the functions performed by a smart grid coordinator.

Five parties submitted comments in response to this request: BHE, CMP, GridSolar, the OPA, and TESM.

Analyzing smart grid tools and administrative and institutional options is complicated because (a) smart grid visions are continuing to evolve rapidly as new technologies and applications develop; (b) many smart grid components help to achieve multiple missions at various levels of the electric grid; and (c) many smart grid functions could involve multiple actors. This situation is fraught with uncertainty, and some of that uncertainty is reflected in differences that appear in the parties' submitted comments.

This paper summarizes and reviews the five parties' filings along with literature about smart grid capabilities and implementation and recommends Commission action based on that information. The recommendations include:

- Some changes to transmission planning rules and cost-allocation practices on Maine's bulk electric system (BES; i.e., the FERC jurisdictional transmission system, under ISO-NE operating rules) are needed to establish a framework that enables non-transmission alternative (NTA) options to achieve their full potential. The Commission should do what it can to ensure rules and cost-allocation practices that promote a full and fair competition between transmission and NTA solutions. This could include identifying one or more Smart Grid Coordinator entity(ies) with the motivation to actively pursue such changes on the regional and national levels.

- For the Maine Local T&D system, the Commission should review and then exercise its authority to require that NTA solutions applicable to the Local T&D level be evaluated in T&D system planning and selected when modeling determines that the NTA solutions are a least-cost option.

- The Commission should consider applying "feebate" policies for the Maine Local T&D system to encourage installing and operating resources in specific areas where the resources will produce the greatest system benefits and minimize system costs.

- The Commission should continue its efforts to begin implementing dynamic pricing, including changes to standard offer service. The Commission should ensure that the early dynamic-pricing efforts are carefully monitored and evaluated. Evaluation data should be used to inform the Commission and all interested parties prior to establishing more widespread dynamic-pricing programs.

- The Commission should not authorize cost recovery for any smart grid facilities that provide customer end-use services unless those facilities use open-systems protocols and can be made available at cost to competitive service providers.

- The Commission should not assume that the T&D company is best suited to smart grid roles involving consumer education and consumer end use. The Commission should determine what parts of the smart grid relationship with consumers are best left to competitive suppliers, and whether and how standard offer service will need to be changed to reflect new smart grid capabilities.

- The Commission should be prepared to assign SGC responsibilities to one or more entities in the near term as a pilot project(s) and then carefully monitor and evaluate the progress in achieving general smart grid and specific NTA objectives. If pilot projects are successful, the Commission should consider temporary or short-term SGC assignments for the purposes of consumer education, NTA identification, NTA procurement, and NTA coordination. Those efforts should also be carefully monitored and evaluated. Then and only then will it be clear whether a more permanent SGC should be established.

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I. Introduction and History of Proceeding

The purpose of this report is to summarize and analyze the information provided in Maine's smart grid coordinator investigation, Docket No. 2010-267,[1] and to make recommendations based on that analysis. To provide a more holistic and inclusive analysis of the smart grid coordinator issue, this report incorporates additional information from sources outside the investigation. Part I includes background information for understanding the issues being investigated in Docket No. 2010-267. Part II explains the information parties were asked to provide in this docket and Part III summarizes the information the parties provided. Part IV presents the author's analysis of that information and the resulting recommendations.

A. Introduction

Smart grid has been a topic of much discussion and excitement in recent years. Melding advanced information communications and control technologies into electricity production, transmission, distribution, and consumption operations promises to deliver substantive, beneficial effects for the widest possible set of energy system management practices, including outage management, voltage monitoring and regulation, distributed generation management, and customer end uses and demand profiles. EPRI (March 2011, p. vii) reports:

> The present electric power delivery infrastructure was not designed to meet the increased demands of a restructured electricity marketplace, the energy needs of a digital society, or the increased use and variability of renewable power production. As a result, there is a national imperative to upgrade the current power delivery system to the higher performance levels required to support continued economic growth and to improve productivity to compete internationally. To these ends, the Smart Grid integrates and enhances other necessary elements including traditional upgrades and new grid technologies with renewable generation, storage, increased consumer participation, sensors, communications and computational ability. According to the Energy Independence and Security Act of 2007, the Smart Grid will be designed to ensure high levels of security, quality, reliability, and availability of electric power; improve economic productivity and quality of life; and minimize environmental impact while maximizing safety. Characterized by a two-way flow of electricity and information between utilities and consumers, the Smart Grid will deliver real-time information and enable the near-instantaneous balance of supply (capacity) and demand at the device level.

As more states recognize the value of investing in smart grid technologies, new questions arise as to how to incorporate these innovations into the nation's aging electric grid. Not only do technical issues abound, a pressing issue for states is how best to implement and regulate this technology. Electricity delivery to customers is the result of a complex network of actors coordinating their various roles in response to a combination of federal and state laws and regulations. With the introduction of smart grid technology, utilities will have deeper, more comprehensive, and higher quantities of data to enable more efficient and effective operation and management of the electric grid. Customers will have increasing opportunities to participate more actively in electricity markets by better managing their electricity consumption through the use of in-home devices such as smart thermostats, smart appliances, and home energy management systems.

Yet for any of these innovations to effectively serve the public good, states must determine which entities will implement the related technologies and services, how and to what degree to regulate those entities, and who will regulate them.

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[1] Maine Public Utilities Commission Docket No. 2010-267, Maine Public Utilities Commission Investigation into Need for Smart Grid Coordinator and Smart Grid Coordinator Standards, http://mpuc.informe.org/easyfile.

The Maine Legislature, recognizing the value of smart grid technology, passed *An Act to Create a Smart Grid Policy in the State* ("*Smart Grid Policy Act*") (P.L. 2010 Ch. 539, codified at 35-A M.R.S.A. § 3143 (2010)).[2] The *Smart Grid Policy Act* states that smart grid functions should be promoted to: (1) improve the overall reliability and efficiency of the electric system, (2) reduce ratepayers' costs in a way that improves the overall efficiency of electric energy resources, (3) better manage energy consumption, and (4) reduce greenhouse gas emissions. (35-A M.R.S.A. § 3143(3)).

The *Smart Grid Policy Act* directs the Maine Public Utilities Commission ("Commission") to investigate the possibility of creating a smart grid coordinator. A smart grid coordinator is defined as an entity "that manages access to smart grid functions and associated infrastructure, technology and applications within the service territory of a transmission and distribution utility" (35-A M.R.S.A. § 3143(1)(B)). The Commission is to determine whether creating one or more smart grid coordinators is in the public interest, and if so, to adopt smart grid coordinator standards (35-A M.R.S.A. § 3143(5)).[3]

Broadly, the intent of public utility regulation is to align private interests with the optimal public outcome (e.g., maximization of social welfare). The regulation of monopoly industries generally intends to produce a close proxy of the economic efficiencies that would otherwise be provided by multiple firms operating in a fully competitive market (see, for example: Priest, 1993; Tomain, 2002). In determining whether there is a need for a smart grid coordinator, the threshold question is whether establishing such an entity will better align private and public interests and more closely approximate the economic efficiencies of a fully competitive market, with the result that the societal benefits outweigh the additional costs.

Maine's Commission is presented with these questions:

1. Is the combination of entities that comprise the existing energy-market structure sufficient to maximize the potential benefits that could be achieved through smart grid deployment and operations?

2. Will additional or different regulatory incentives and performance objectives be required to lead the existing industry structure to maximize smart grid benefits? If yes, what changes are required?

3. Will the creation of a new entity, presently known as a smart grid coordinator (SGC), improve upon the status quo? If yes, how and why?

If the third question is answered in the affirmative, then the Commission will have to consider in further detail the functions to be assigned to a smart grid coordinator and how that new entity will be selected and monitored.

The primary question in the Maine investigation is whether it is in the public interest to create a smart grid coordinator and how that coordinator could assist in achieving the following smart grid goals, identified in 35-A M.R.S.A. § 3143(3):

1. Increased use of digital information and control technology to improve the reliability, security and efficiency of the electric system;

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[2] http://www.mainelegislature.org/legis/statutes/35-A/title35-Asec3143.html.

[3] The legislation does not allow more than one smart grid coordinator per electric utility service territory, but the Commission could decide that a single entity will fulfill the role for more than one service territory, or even for the whole state.

2. Deployment and integration into the electric system of renewable capacity resources… that are interconnected to the electric grid at a voltage level less than 69 kilovolts;

3. Deployment and integration into the electric system of demand-response technologies, demand-side resources, and energy-efficiency resources;

4. Deployment of smart grid technologies, including real-time, automated, interactive technologies that optimize the physical operation of energy-consuming appliances and devices, for purposes of metering, communications concerning grid operation and status, and distribution system operations;

5. Deployment and integration into the electric system of advanced electric storage and peak reduction technologies, including plug-in electric and hybrid electric vehicles;

6. Provision to consumers of timely energy consumption information and control options; and

7. Identification and elimination of barriers to adoption of smart grid functions and associated infrastructure, technology, and applications.

Would a centralized management entity, such as a smart grid coordinator, be better able to effect change toward achieving these smart grid goals? Or might the existing entities in the electricity arena – the incumbent transmission and distribution utilities, independent generators, competitive energy providers (CEPs), Efficiency Maine Trust,[4] and end-use consumers – efficiently and effectively achieve these goals on their own? If the existing entities are not likely to achieve the goals, then what might be other successful policy options, instead of establishing a smart grid coordinator, to align private interests with the public interest of maximizing smart grid benefits minus costs?

Further questions arise around the potential benefits and costs of a smart grid coordinator. How can the proposed smart grid planning and implementation system ensure economic efficiency? What are the potential benefits and costs associated with establishing, operating, and providing oversight for a smart grid coordinator? What functional responsibilities will the smart grid coordinator assume? What is the likelihood that the value of incremental benefits a smart grid coordinator can achieve will exceed the combined incremental costs of instituting and providing oversight for a smart grid coordinator?

B. Procedural history of Maine's smart grid investigation

On September 8, 2010, the Commission initiated an investigation to determine whether it is in the public interest to have one or more smart grid coordinators in the state. *Notice of Investigation*, Docket No. 2010-267. The Commission then issued a procedural order seeking comment from interested parties on "specific smart grid technology, operational and institutional measures" that would achieve the *Smart Grid Policy Act's* objectives of improving the efficiency and reliability of the electric system, better managing electricity consumption, and reducing greenhouse gases. Docket No. 2010-267 at 1 (Oct. 7, 2010). The Commission also requested comments on what role a smart grid coordinator would play in achieving these objectives. Attached to the *Procedural Order* was a draft outline of pertinent issues (Appendix One), which the Commission asked the parties to use for framing their comments.

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[4] The Efficiency Maine Trust was created to administer energy efficiency and alternative energy programs in the state of Maine. It was initially established by the Maine Legislature and was managed by the Maine Public Utilities Commission. As of 2010, it is no longer managed by the Maine Commission and instead operates independently from the Commission. See http://www.efficiencymaine.com/about.

To begin the process of understanding whether a need exists for a smart grid coordinator, the Commission set forth, with input from parties, the following definition of smart grid:

> Smart grid systems would further one or more of the four policies noted [in the *Smart Grid Policy Act*] by affecting the design and/or operation of the electricity system at any point from the bulk transmission system level down to the end-user. Smart grid would include advanced and digital devices, technologies and systems; communication, information, monitoring and control systems, including real-time communication systems; and related operational protocols. By way of example, smart grid systems could enable greater efficiency in system design and operations and/or enhance potential for demand response[,] distributed generation[,] and smart appliances.[5]

This definition creates an initial scope of the potential roles and responsibilities of an SGC. Various other definitions of smart grid have been compiled that focus on the technical components and/or potential smart grid capabilities (see, for example: Kranz and Picot, 2011, pp. 10-11; Morgan et al., 2009, p. 1; and Stanton, Feb 2011, p. 1). While these other definitions offer further guidance, the definition established by the Commission forms the basis of the SGC evaluation process in Maine.

Accompanying the order outlining this smart grid definition was an appendix outlining questions meant to better inform the Commission's understanding of the smart grid and to frame the conversation about a potential SGC. The questions were separated into four levels of the utility system: (1) the bulk transmission system; (2) the local Maine transmission and distribution system; (3) generation resources; and (4) customer end use. The Commission solicited information about: (a) existing smart grid technologies in use or presently being deployed; (b) potential smart grid technologies that might be adopted, to the extent they can now be foreseen; and (c) the perceived role of an SGC in facilitating deployment and operations of smart grid technologies and functions.

In response to the Commission's *Procedural Order*, 11 parties intervened. The parties, in order of appearance, include: Maine's Office of the Public Advocate (OPA), Environment Northeast, Central Maine Power (CMP), Grid Solar, Thermal Energy Storage of Maine (TESM), the University of Maine's Smart Grid Center, Bangor Hydroelectric Company (BHE), the Maine Renewable Energy Association (MREA), the Industrial Energy Consumer Group (IECG), the Conservation Law Foundation (CLF), and Efficiency Maine Trust (EMT).[6] Five parties submitted comments in response to the October 27 *Procedural Order* by December 16, 2010: BHE, CMP, GridSolar, the OPA, and TESM. Written data requests by Commission Staff were issued on January 20, 2011 for discovery on the submitted responses to the outline. Responses to the data requests were provided by parties by February 17, 2011, and a technical conference for further discovery and discussion of the case was scheduled for May 12, 2011 but later delayed to June 7, 2011. Following the technical conference held on June 7, 2011, responses to oral data requests were filed by July 7, 2011.

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[5] *Procedural Order*, Docket No. 2010-267 (Oct. 27, 2010). This definition expands upon the definition of smart grid provided in statute (35-A M.R.S.A. § 3143(1)):

> "Smart grid" means the integration of information and communications innovations and infrastructure with the electric system to enhance the efficiency, reliability and functioning of the system through smart grid functions. (http://www.mainelegislature.org/legis/statutes/35-A/title35-Asec3143.html).

[6] Efficiency Maine Trust did not file its Petition to Intervene until June 8, 2011. Its Petition was granted on June 30, 2011.

C. Why are these questions important?

Information technology is quickly altering the landscape of both telecommunication and electric utilities. As the *Smart Grid Policy Act* makes clear, Maine desires to implement smart grid technologies and thereby reap the associated benefits.

Designing and implementing a coordinated strategy, though, necessitates attending to the potential problems that could result from smart grid adoption. For example, increasing the exchange of information between consumers and others, and relying on that information exchange for improved grid and energy services management, raises concerns about cyber security and information privacy (Wokutch, 2011). Another concern that has been raised is the potential that dynamic-pricing tariffs enabled by advanced metering infrastructure could result in increased costs for some customers who can least afford it.[7] And the costs associated with particular smart grid improvements must be weighed against their benefits.

Maximizing smart grid benefits will require regulations and incentives for entities in the electricity sector to be aligned with public policy goals. For instance, in New England transmission reliability upgrade projects costs are spread, proportionately according to usage, amongst all ISO-NE transmission users. The ISO-NE Open Access Transmission Tariff designates investments that receive this regional cost-sharing treatment as Pool Transmission Facilities (PTF). Based upon their ratio share of load, Maine ratepayers presently pay about 8% of the total cost of construction, operation, and maintenance for PTF projects. However, non-transmission alternatives, which conceivably could provide a more cost-effective solution to a particular reliability problem, do not receive the same rate treatment under present ISO-NE rules. This means that Maine ratepayers could be allocated 100% of the cost of any non-transmission alternative (NTA) that is paid for by Maine utility companies. Some NTA investments would be made by entities other than utility companies, though. Non-utility NTA investments would be made because customers or energy-service providers expect to make money by providing energy services to the grid or by avoiding utility bills for specific consumers. Ratepayers would not be directly charged for those investments. While there are this and other caveats to the cost allocation for NTA projects, this example illustrates the potential mismatch between existing regulations and financial incentives and the least-cost provision of utility service.

Utilizing smart grid technologies to enable the use of distributed resources in NTA projects expands upon Maine's longstanding tradition to pursue distributed electricity generation. In 1987, the Maine Legislature led efforts to increase small energy production in Maine, finding "that the development of small energy production facilities using renewable resources and cogeneration facilities will have a significant and beneficial effect upon this State" (35-A M.R.S.A. § 3302 (1987)).[8] As of 2009, Maine leads the nation in the market share of non-hydro renewable generation, at 23%, and with hydro included, the state achieves 50% renewable generation (NREL, 2010). Maine also ranks third in the nation, behind Alaska and Vermont, in the share of interconnected distributed generation capacity (EIA, 2008). The smart grid's increased information and understanding of transmission system conditions should empower distributed resources, particularly distributed generation, to produce and deliver ancillary benefits such as reduction of local load demand, along with its resulting need for additional transmission capacity.

More generally, the increased use of smart grid technologies holds the promise of increased transparency, reliability, and resiliency of electricity production and use, at lower overall costs to society. In considering a smart grid coordinator with responsibilities for the planning and implementation of NTAs, the analysis

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[7] Early smart grid program evaluation data does appear to allay this concern, at least partially. See, for example, Faruqui & Parmeri, 2011.

[8] 35-A M.R.S.A. § 3302, last amended in 2001, at: http://www.mainelegislature.org/legis/statutes/35-A/title35-Asec3302.html.

and provision of least-cost solutions to reliability upgrades should be rigorous. Further, distributed resources, composed of a multitude of technologies including generation, storage, and demand response, provide inherent system benefits that resist common mode failures and imprecise, frequently sluggish, responses to changes in electricity demand at various time scales.

While this report is based on the Maine investigation and Maine's specific energy-industry structure, the author believes the insights provided will be useful to other states as well. The existence, form, and benefits associated with smart grid coordination will vary, depending upon the specifics of a region's electricity industry structure. What may be appropriate for a jurisdiction with vertically integrated investor owned utilities, with revenues directly linked to electricity sales, might not be appropriate for another—for example, a region that has a competitive market structure and utility revenues decoupled from electricity sales.

II. The Commission's Inquiry in Docket No. 2010-267

As part of the structured comments outline, parties were asked to describe each smart grid technology and system and its intended function and explain how it achieves its intended purpose. For future smart grid technologies, parties were asked to address what each technology does and to describe the technology's commercial availability and viability. For applications at the bulk power and Maine local T&D system levels, parties were asked to explain the planning and decision-making process by which the technology or system would be considered. (Procedural Order, October 27, 2010, Appendix One).

Furthermore, with respect to future smart grid applications for the Maine local T&D system, the parties were asked to:

> Describe operational and/or institutional changes, e.g., smart grid coordinator, that would enhance the value of the technology or system. In particular, describe the specific roles of a smart grid coordinator in planning and operating the systems in Maine. How would coordination with other system operators, e.g., ISO, be assured? What would a smart grid coordinator's status be with respect to FERC [Federal Energy Regulatory Commission], NERC [North American Electric Reliability Corporation] or other federal jurisdiction? State jurisdiction? Identify strengths and weaknesses of having a smart grid coordinator perform these functions rather than the utilities and/or ISO. Identify additional costs that would be caused by having the functions performed by a smart grid coordinator. (Procedural Order, October 27, 2010, Appendix One, p. 2).

These tasks are difficult, though, because the subject of smart grid itself is complex and evolving. The *Procedural Order* in Docket 2010-267 anticipated uncertainty, including the many different definitions and descriptions and the evolving nature of smart grid technologies and deployment (*Procedural Order*, October 27, 2010, p. 2).

Figure 1 depicts one recent concept of smart grid, but not everyone uses the same terminology when describing smart grid components and functions. And there is no universally accepted set of technologies or functions that comprise smart grid, nor a typology explaining which technologies will provide what explicit benefits in the various domains. As Wokutch (2011, pp. 523-33) observes, smart grid could involve "many products and services that promise to transform and modernize the grid in myriad ways… [and a] seemingly endless number of new and developing… products and services."

These uncertainties result in some difficulty in assigning the various hardware and software components and their associated benefits with the explicit domains of the system and the various missions or purposes smart grid is intended to achieve. There are overlaps across multiple domains, as multiple benefits are enabled by individual technologies and groups of technologies. Complexity and uncertainty exist because of the large number and variety of actors that can or will be involved in smart grid. In addition, the regulations and incentives facing the various market participants are subject to change, and the potential roles of third-party service providers (TSPs)[9] and customers in using smart grid technology to most efficiently manage energy use are not yet thoroughly understood. Smart grid in Maine, for example, will affect operations for ISO-NE, the Maine Local Control Center (MLCC), transmission and distribution utilities, competitive energy providers, and customers, not to mention all the hardware and software vendors producing, providing, and supporting the smart grid equipment and functions. In addition,

[9] In this context, a TSP provides energy services to retail consumers, but those services include neither T&D, which would be provided by a T&D utility, nor electricity generation nor natural gas commodity service, which would be provided by a competitive energy provider (CEP). Common examples of TSPs include curtailment service providers (CSPs) that aggregate demand response and energy service companies (ESCOs) that provide energy-efficiency services. TSPs could also provide on-site electricity generation or combined heat and power (CHP) systems, either as developers or owner-operators.

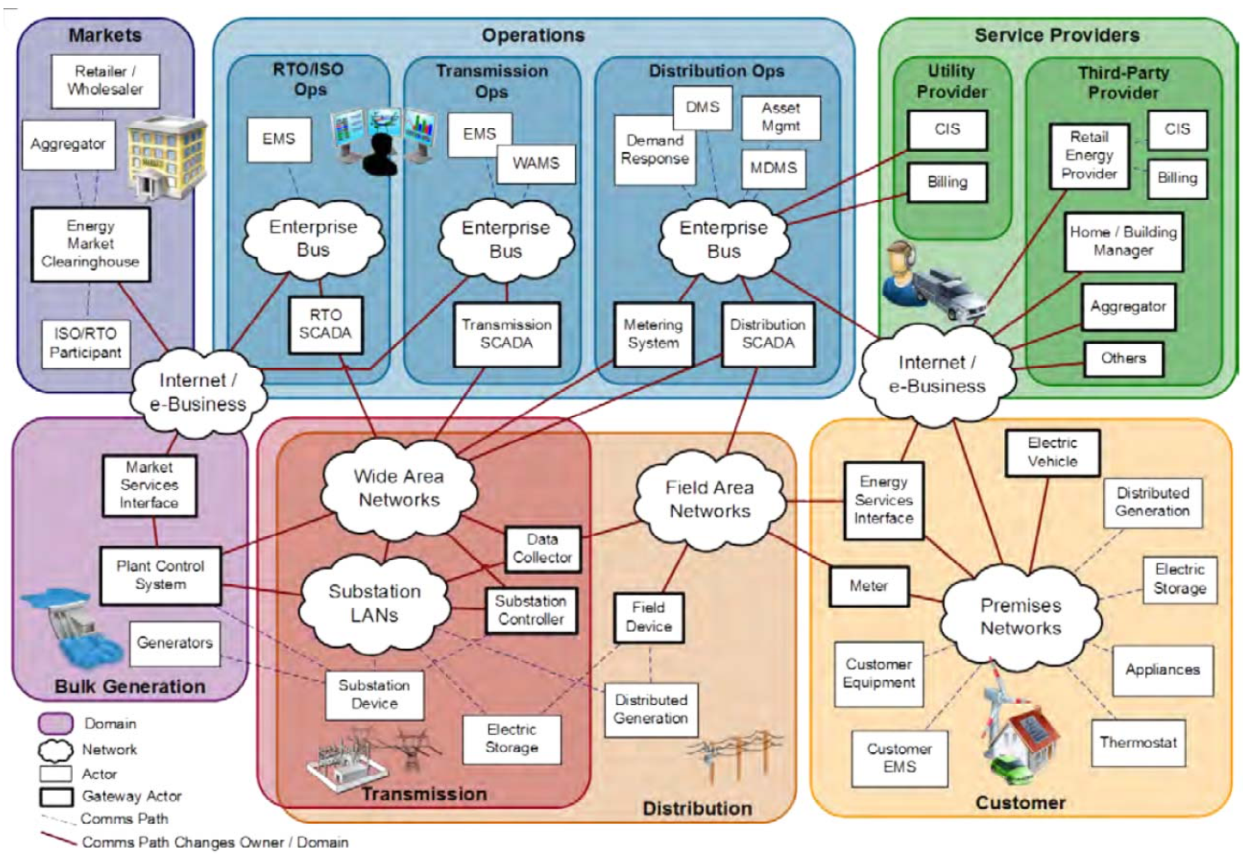
curtailment service providers (CSPs) and TSPs could have roles in providing services to consumers, enabled by smart grid technologies.

In this context, it should be noted that some of these potential market participants are not represented among the parties participating in Case No. 2010-267. For example, no CEP or CSP is participating and only one TSP, TESM, is a party to the case.

Finally, the Commission must consider whether and how the milieu would be changed due to the presence of a smart grid coordinator and depending on the roles and responsibilities given to and incentives affecting the smart grid coordinator.

All of these uncertainties and complexities add to the difficulty of understanding the benefits and costs associated with establishing a smart grid coordinator for the state of Maine. Part III of this report summarizes the information provided by the parties in Docket 2010-267, and Part IV provides analysis and recommendations based on that information.

Figure 1: Smart Grid Domains, Networks, and Actors



Source: Illinois Statewide Smart Grid Collaborative, September 30, 2010, *Collaborative Report*, p. 47.

III. Summary of Parties' Responses

Following issuance of a *Procedural Order* on October 7, 2010, five parties filed documents providing recommendations on the proposed definition of smart grid and the *Draft Outline* about the issues to be addressed in comments. After receiving the parties' recommendations on the *Draft Outline*, the Commission issued a subsequent *Procedural Order* on October 27, 2010, including a revised *Final Outline* that incorporated several revisions recommended by the parties.

Responses to the October 27 *Procedural Order* were filed by BHE, CMP, GridSolar, the OPA, and TESM.

A. Summary of the parties' positions on smart grid

BHE says its comments "roughly correspond to the Final Outline." (*Bangor Hydro Electric Company's Comments*, Docket No. 2010-267, Dec. 16, 2010, p. 1).[10] BHE concludes:

> To the extent that the Commission believes that the appointment of a smart grid coordinator is appropriate, Bangor Hydro believes that it is currently best situated to perform those actions properly identified as the role of such a coordinator, without burdening its customers with the significant increased cost that would likely result from an independent coordinator. (BHE, p. 18).

After nearly 12 pages of introductory explanation, *Comments* from CMP generally follow the *Final Outline*. (*Comments of Central Maine Power Company in Response to Commission Inquiry*, Docket No. 2010-167, December 16, 2010).[11] CMP indicates:

> CMP's Smart Grid vision is to provide smart devices on all parts of the system from the bulk power system, to distribution, the entire customer base, and beyond. A system fully metered, monitored, and controlled provides integrated grid operations, access for competing providers, and enhanced customer services that maximize benefits. This vision is based on four elements: (1) an Advanced Metering Infrastructure ("AMI") system for all customers; (2) a modern control center and management system; (3) use of digital equipment to automate and control the grid; and, (4) new customer services to enhance customer value and reduce environmental harm. (CMP, p. 1, footnote omitted).

CMP's conclusion is somewhat similar to BHE's. Both companies believe, as CMP summarizes:

> [Smart grid's] operational scope and complexity indicates the need for CMP to prudently manage the system from end-to-end. Three key priorities alone – reliability, system security, and open access to the grid – suggest the need for a single Smart Grid operator. In this light, the role of a Smart Grid coordinator seems better suited to fulfill commercial needs, such as to aggregate third party providers of Smart Grid services, and that it remain separate from Smart Grid operations. (CMP, p. 2).

GridSolar provided what it entitled its *Direct Case*. (*GridSolar Direct Case*, Docket No. 2010-267, December 16, 2010).[12] This document includes both a nine-page "general discussion of 'Smart Electric

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[10] In the remainder of this report, unless otherwise noted, references to "BHE" refer to these *Comments*, dated December 16, 2010.

[11] In the remainder of this report, unless otherwise noted, references to "CMP" refer to these *Comments*, dated December 16, 2010.

[12] In the remainder of this report, unless otherwise noted, references to "GridSolar" refer to this *Direct Case*

Grids' to serve as a possible point of common understanding and agreement" and GridSolar's response to the Final Outline. (Docket 2010-267, Dec. 16, 2010, p. 2).

The OPA provided *Direct Testimony of J. Richard Hornby and Martin R. Cohen* (Docket 2010-267, Dec. 16, 2010).[13] The two energy regulatory consultants provided their "evaluation of whether it is in the public interest to establish a Coordinator." (OPA, p. 2). The OPA consultants stated that their testimony "does not readily fit into…the outline in the October 27 Procedural Order." (Docket 2010-267, Dec. 16, 2010, p. 5). Mr. Hornby and Mr. Cohen share four conclusions. First, they indicate:

> [U]tilities have the responsibility, financial incentive and expertise needed to achieve the direct benefits to their transmission and distribution systems enabled by smart grid technology. However, various barriers need to be overcome in order to readily and fully achieve the economic, energy and environmental benefits to customers and society enabled by this technology. (OPA, p. 3).
>
> * * *
>
> [B]arriers include inadequate positive financial incentives for utilities and retail energy suppliers, customer engagement challenges, lack of core competencies in certain key areas, and uncertainty regarding how best to achieve those benefits. (OPA, p. 36).

Second, the OPA consultants identify several smart grid functions that they believe will not be fully achieved through the individual or combined actions of the existing parties active in Maine's electric utility industry. Thus, they conclude that "for a sub-set of smart grid functions, the concept of establishing a Coordinator is sufficiently in the public interest to justify moving to Phase II of this proceeding." (OPA, p. 3). They state:

> [N]o individual entity, or category of entities, currently providing services in Maine's electricity market has either the regulatory obligation or the financial incentive, or both, to proactively manage access to all smart grid functions. (OPA, p. 13).
>
> * * *
>
> Our review indicates that the financial incentives and regulatory obligations of the parties currently operating under Maine's existing electricity market structure and regulatory framework are not fully aligned with the achievement of all seven goals in the Smart Grid Act. Because of those gaps, the potential for all seven specific goals of the Act to be achieved effectively is higher with a Smart Grid Coordinator than without one. (OPA, p. 19).

Third, Hornby and Cohen conclude that "a final determination of whether establishment of a Coordinator will, or will not, be in the public interest cannot be made until Phase II issues are successfully resolved." The answer, they say, "will depend on whether a reasonable approach can be identified for structuring, implementing, and regulating the Coordinator." (OPA, p. 3). They recommend that Phase II include a benefit-cost analysis to determine the value to ratepayers of establishing a Coordinator. (OPA, p. 4).

Fourth, the OPA consultants conclude that determining whether it is best to select "different Coordinators for each [utility] service territory, the same Coordinator for more than one service territory, or a single statewide Coordinator" should await "consideration of utility-specific and statewide issues… in Phase II… or in subsequent proceedings… ." (OPA, p. 4).

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document, dated December 16, 2010.

[13] In the remainder of this report, unless otherwise noted, references to "OPA" refer to this *Direct Testimony*, dated December 16, 2010.

TESM limited its comments to dynamic line rating (DLR) technology, its use with electric thermal storage (ETS) for space and water heating, and the possibilities of utilizing these technologies along with dynamic electric rates and electric power from variable output generators, like wind, to provide consumers with an economical alternative to space and water heating using fuel oil. (*Comments of Thermal Energy Storage of Maine*, Docket 2010-267, Dec. 16, 2010).[14] TESM explains that ETS heating elements can be controlled remotely or through "computer programs operating free of utility control, but using data obtained from utility systems." TESM says the ETS technology offers "storage capacity available for handling intermittent wind loadings, voltage regulation requirements, or any other service that a fully dispatchable storage resource can offer the grid." (TESM, p. 3). The DLR technology would allow use of ETS only when "surplus capacity" is available on the T&D lines. The coordination with DLR would prevent ETS use from adding load to already-stressed transmission or distribution lines, ensuring that the ETS use would not necessitate incremental T&D infrastructure. (TESM, p. 5).

B. Maine's Bulk Electric System (BES) and Primary Transmission Feeder (PTF) power system

BHE lists what it identifies as "the larger components of 'smart technology' used… on its Bulk, PTF, Local Transmission and Distribution system." It says, "This listing is not intended to be… all inclusive." (BHE, p. 2). The technologies include supervisory control and data acquisition (SCADA), remote terminal units (RTUs), microprocessor-based relaying, programmable logic controllers (PLCs), communication multiplexers, digital fault controllers (DFRs), sequence-of-events recorders (SERs), and synchrophasors. For each, BHE briefly describes the technology and explains its operations. BHE states:

> All [the] systems are owned and operated by Bangor Hydro. ISO-NE provides switching oversight and operational set points for Bulk Power System. These switching orders are communicated to Bangor Hydro via Central Maine Power. (BHE, p. 4).

Regarding future technology and operational changes, BHE describes the ISO-NE "Synchrophasor Infrastructure and Data Utilization Project." BHE also lists frequency regulation using flywheel storage on the bulk power system and bulk battery storage. (BHE, pp. 4-6).

CMP indicates that the company is upgrading its energy control center (ECC) to include an energy management system (EMS), SCADA, a distribution management system (DMS), and an outage management system (OMS) platform. (CMP, p. 3).

CMP reports operating its bulk power and PTF system using "a two-way communications, metering and control system." CMP indicates that five of its six 345kV substations already have full SCADA and the sixth has partial control. At the Company's 74 substations operating at 115kV, 49 have full SCADA and 21 have partial control. (CMP, p. 13). CMP indicates that it is in the process of eventually adding to all substations SCADA capabilities and an integrated EMS/DMS/OMS capability. (CMP, pp. 3, 21-24).

GridSolar notes that "rapid technological advances, new equipment and software, and new standards and protocols may make [SCADA] upgrades possible at less cost." GridSolar recommends, "These new data collection and processing technologies should be fully explored." (GridSolar, pp. 13-14).[15]

CMP explains that it is registered with the NERC as a transmission owner, operator, planner, and service provider; a distribution provider; and a load-serving entity. Inherent in managing these roles, CMP staff must meet NERC training standards and obtain NERC operating credentials, including for cyber security

[14] In the remainder of this report, references to "TESM" are to these *Comments*.

[15] Both CMP and GridSolar discuss adding to substations the SCADA and associated equipment as an activity relevant to the Maine Local T&D system rather than the Bulk and PTF system. See also GridSolar, p. 17.

and system restoration plans. (CMP, pp. 15-16).[16] CMP says that grid operational roles could not be assumed by a Smart Grid Coordinator without incurring duplicative costs and increasing reliability and security risks. CMP points out that "partitioning… responsibilities required to allow a Smart Grid coordinator to take on grid operations roles seems likely to require extensive new rules to define the interactions and responsibilities… ." CMP concludes that it would be tantamount to "having 'two sets of hands on the wheel' in the complex and dynamic grid operator environment… ." (CMP, p. 12).

For the future, CMP identifies new or pending requirements forthcoming from NERC, the Northeast Power Coordinating Council (NPCC), and FERC. These include existing and upcoming standards for smart grid policy and reliability, under-frequency load shedding, and critical infrastructure protection. CMP also points out that a recent FERC directive (in FERC Docket No. RM09-18-000) "will increase the number of facilities" defined as part of the bulk power system. (CMP, pp. 17-18). BHE mentions NERC cyber security standards in the context of the Maine Local T&D System rather than the Bulk and PTF system (BHE, pp. 11-12).

CMP indicates that "traditional planning processes used for transmission, distribution, and related equipment will be used to evaluate the cost-effectiveness of possible [smart grid bulk power and PTF] system upgrades… ." (CMP, p. 20)

GridSolar identifies SCADA and the associated communications systems as the presently implemented smart grid components for the Bulk and PTF system. For future Bulk and PTF technologies, GridSolar identifies "synchrophasor measurements and the use of phasor data for planning and operational system analyses" and DLR.[17] GridSolar notes that "[c]osts are difficult to determine at this time…" GridSolar concludes that other smart grid "technologies and system upgrades… are needed on the local T&D system, at generation facilities, at the meter, and in consumer premises," not on the Bulk and PTF system. However, GridSolar expects that Bulk and PTF system smart grid software will be continuously upgraded for improved diagnosis, management, and response (GridSolar, pp. 12-13).

C. The Maine Local T&D system

BHE's *Comments* list several smart grid technologies already in place or being deployed in its service territory. These include its existing geographic information system (GIS) and advanced metering infrastructure (AMI). BHE reports that it has nearly completed the installation of smart meters for all its customers and is in the process of installing a meter data management system (DMS) and "customer-facing web portals." (BHE, pp. 6-7). BHE notes that its AMI meters will enable "[a]ccess to usage information for internal and external customers." (BHE, p. 7). BHE reports that its AMI meters are capable of registering "reverse rotation… [measuring] the quantity of kWh passing backwards through the meter." (BHE, p. 9). BHE also lists AMI-equipped mobile trailers that will be deployed for use in substation maintenance; reconnect collars that will enable remote service disconnections and connections; security hardware and software; upgraded substation equipment; and web presentment software. BHE is implementing one web portal for commercial and industrial customers and another for residential customers. The Company also plans to implement "specialized web presentment software." (BHE, pp. 8, 10). BHE indicates that it will own and operate all of the various smart grid components it describes for implementation in the Maine Local T&D System. It lists the various contractors it has selected to provide the various components. (BHE, p. 10).

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[16] GridSolar (p. 12) also states, "CMP serves as the NERC Registered Transmission Operator, and the CMP Dispatch & Energy Control Center Department operates the MLCC under the supervision and direction of the Independent System Operator – New England (ISO-NE)… the registered NERC Reliability Coordinator, Balancing Authority, Transmission Operator, and Regional Transmission Organization for the New England Control Area."

[17] GridSolar also discusses DLR in the context of Generation Resources (GridSolar, pp. 28-29 and Attachment 5).

Similarly, CMP reports that it is nearly finished deploying AMI to all of its customers and expects to complete those installations by March 2012. (CMP, pp. 2-3, 5-6). CMP says its system will provide:

> (1) 100% deployment of AMI to all 610,000 electricity customers - residential, commercial and industrial; (2) a full two-way communications service offering that includes regular interval meter reads and remote connect-disconnect; (3) a web-based customer information portal to provide full interactive services; and (4) a facilitation and support capability for future Smart Grid customer initiatives. (CMP, pp. 2-3).

CMP indicates that it is building "a private [internet protocol] IP-based Wide Area Network (WAN)… across CMP's service territory." (CMP, p. 6). It says the AMI system, including the WAN,

> will enable extensive communication, distribution grid monitoring, and control to gain major grid efficiencies, increase reliability, reduce outage times, and reduce overall system costs. This element is also critical to enable integration of detailed customer and system load information into distribution system operations. (CMP, p. 6)

Neither BHE nor CMP provides data about the expected costs and benefits associated with these facilities. BHE lists only categories of benefits, such as reduced field visits and improved efficiency for field operations; enhanced outage management and power-quality analysis; reduced CO_2 emissions associated with reduced vehicle usage associated with meter reading; improved security and protection; and providing usage information to enable customers "to better manage their electricity costs." (BHE, pp. 6-10). BHE does state:

> Data collected from [smart] meters has already allowed Bangor Hydro to operate more efficiently by reducing meter reading staff, vehicle costs, and improved outage management. The resulting cost reductions have contributed to reduced customer rates for the past several years. (BHE, p. 9).

CMP indicates that the smart grid capabilities installed on the Maine Local T&D system will "enable customers to take advantage of grid operations to increase reliability, obtain incentives, realize more local distribution level market benefits, and reduce overall costs." (CMP, p. 23).

Looking to the future, BHE describes four smart grid systems and capabilities: (1) "Cyber Security and the upcoming changes that NERC is proposing;" (2) revenue-protection software to "improve theft-of-service detection, enable subsequent revenue recovery, and ultimately reduce theft on the system; (3) demand-response capability, using demand-response units (DRUs) to control electric water heaters and "other loads such as a central air handling unit, air conditioner, or a pool pump;" and (4) improved distribution load analysis capability. (BHE, pp. 11-13).

BHE describes its decision-making process as follows:

> A key part of our strategy is to closely monitor new developments and technology advancements in the Smart Grid space and to bring promising new innovations forward for further evaluation. (BHE, p. 13).

BHE says it uses "a rigorous Decision Analysis process" for assessing "all significant projects or opportunities." (BHE, p. 14; see also June 7, 2011 *Transcript of Technical Conference* in Docket No. 2010-267, pp. 123-124).

Similarly, CMP says its decision making on these technologies uses "traditional planning processes" that would be supplemented by "emerging NIST standards." CMP explains:

> When analyzing our worst performing circuits, smart grid capability will be used as a tool to improve CAIDI and SAIFI. Also, when analyzing circuits for customer development or planning purposes, smart grid functionality will be assessed as a method to defer or eliminate traditional capital improvements. (CMP, p. 24).

Regarding the possible planning and operational roles for a smart grid coordinator, BHE warns that those functions "would be duplicative at best… [and] could usurp or conflict with" authority that FERC has already delegated to ISO-NE. BHE concludes:

> At the Maine local transmission and distribution levels, it is essential that such a coordination function be in harmony with the ISO's region-wide coordination. Bangor Hydro, which already works closely with ISO-NE in the planning and operation of its transmission system, is best suited to assume any necessary coordinator role within its service territory. In implementing the AMVSmartGrid upgrades recently approved by the Commission in Docket No. 2006-661(II), Bangor Hydro is already assuming many of the coordination functions that we expect are required to maximize the value of this investment to our customers. Because the Company is a T&D utility subject to regulation, the Commission will be better positioned to ensure that customers receive all the benefits they are entitled to if Bangor Hydro retains these responsibilities. This is particularly important in light of the dynamic nature of the Smart Grid, as Bangor Hydro will be in the best position to respond to the changing needs of its customers and the constant evolution of the technologies. Finally, Bangor Hydro will be able to utilize existing processes and personnel to perform the needed coordination functions with little additional cost, while an independent coordinator will need to recreate and duplicate many of these activities, adding a new layer of expense onto the backs of our customers. Especially in light of the fact that many of these functions have yet to be fully fleshed out, it seems prudent for Bangor Hydro to be designated as the entity responsible for these activities, at least in the near term. (BHE, p. 15).

CMP indicates that a Smart Grid Coordinator might facilitate "providers of generation, demand response, and storage options to be interconnected… ." CMP notes that FERC has already opened regional electricity markets to Aggregated Retail Customers (ARCs), for providing demand response. CMP further says that a Smart Grid Coordinator might "be involved in marketing and encouraging more market participants… ." (CMP, pp. 24- 25). CMP questions, though, whether the available marketing opportunities create a need for designating a Smart Grid Coordinator. CMP believes multiple competing companies can already provide such services today. Therefore, CMP surmises that designating a specific entity to be Smart Grid Coordinator might discourage other parties from entering applicable markets and thus reduce the total level of energy conservation. (CMP, p. 25).

GridSolar reports on the Maine Local T&D system only with respect to CMP's system and the AMI deployment efforts of both BHE and CMP. GridSolar says it has "no comparable information" for Maine's other utilities. For CMP's existing Maine Local T&D system smart grid technologies, GridSolar includes SCADA, voltage reduction capability, and under-frequency load shedding capability. (GridSolar, pp. 14-15).

GridSolar states that future smart grid standards are "ongoing and highly dynamic." GridSolar proposes:

> One of the primary tasks of a Smart Grid Coordinator will be to monitor the development and approval of such standards to ensure that all smart grid activities in the state comply with all existing standards and legal requirements, and that all new smart grid investments are compatible with expected future standards and requirements. (GridSolar, p. 16).

For future smart grid technologies and systems applicable to the Maine Local T&D System, GridSolar lists completion of the SCADA and AMI systems, intelligent distribution devices like smart appliances and smart thermostats, and eventually automated demand-response services. GridSolar also mentions line monitoring equipment, which it says can be instrumental in dispatching distributed generation resources including demand response. GridSolar recommends installing line monitoring equipment on "congested circuits and subregions with the greatest potential for cost-effective NTA solutions." (GridSolar, pp. 17-18).

GridSolar proposes establishing a smart grid control center (SGCC) with staffing from both utilities and a Smart Grid Coordinator. The proposed SGCC would: (1) "monitor electrical conditions on the grid and respond to potential problems;" (2) process "information collected about the grid… to develop and recommend to the Commission NTA solutions;" and (3) "provide information about the grid to third-parties who can… develop distributed generation resources, demand-response, geo-targeted energy efficiency and other solutions to meet actual and anticipated grid reliability problems." (GridSolar, p. 18).

GridSolar cites these benefits associated with the build-out of smart grid capabilities throughout the Maine Local T&D system and coordination through the SGCC: optimizing asset utilization and efficient operation; enhancing reliability; reducing widespread outages; improving power quality; improving security and reducing vulnerability; and improving safety. (GridSolar, pp. 19-20).

Regarding planning, operations and coordination, GridSolar states, "Ownership, management, and control of smart grid equipment will follow the current organization of the grid." That means the utility would have "primary responsibility for constructing and maintaining all aspects… [and] for planning upgrades, expansions, and routine maintenance… ." (GridSolar, pp. 20-21).

In addition, though, GridSolar calls for establishing a Smart Grid Coordinator. GridSolar explains:

> [T]o design and recommend to the Commission optimum solutions to grid reliability issues, the SGCC staff must be independent of any incumbent entities that have vested interests in current grid infrastructure. Perhaps more importantly, they should also be specifically incentivized to design reliability solutions that produce the greatest energy savings at lowest cost, and which reduce energy use and emissions. … While [smart grid] changes will improve the economics for ratepayers and reduce energy consumption and emissions, they may not always result in the maximum financial returns that incumbent utilities seek for their shareholders. Thus, it is critical to have a fully independent entity responsible for operating the SGCC and for developing NTA solutions. (GridSolar, p. 21).

The OPA consultants generally believe that Maine's T&D utilities can successfully implement the smart grid technologies necessary to maximize benefits for the Maine Local T&D System. The consultants observe:

> The one goal likely to be pursued on a state wide basis is "…use of digital information and control technology to improve the reliability, security and efficiency of the electric system." We expect that Maine's T&D utilities will pursue that goal because it is in their financial interest to do so and because they are obligated to do so. Under Section 301 of Maine's public utility statute, local T&D utilities subject to Commission regulation have the responsibility and authority to ensure safe, reasonable and adequate service at rates that are just and reasonable. (OPA, p. 18).

D. Generation resources

BHE refers to generation resources only to note that the company uses its remote interface gateway (RIG) technology to monitor and control its diesel generation assets. (BHE, p. 15).

CMP reviews its role in implementing its *Transmission and Distribution Interconnection Requirements for Generation* and the Commission's recently adopted Chapter 324 rules for integration of small and non-FERC generation resources. CMP notes that all of the operational issues involved with integrating generation into the grid fall under FERC and NERC requirements and thus implicate the utility as the service provider (CMP, pp. 25-27).

CMP does not identify any opportunities for a Smart Grid Coordinator to improve the siting or dispatch of generation resources in Maine or the region. With respect to generation resources, CMP states:

> It is unclear how the Smart Grid coordinator would function or where it would provide major advantage for smart grid participants. … It is clear that the Smart Grid coordinator should not be involved in distribution system operations, as this could compromise system security and reliability. (CMP, pp. 26-27).

OPA purports that no retail service entity presently has an incentive to provide storage. (OPA, p. 18).

Only GridSolar identifies opportunities for a Smart Grid Coordinator to produce advantages for generation resources. GridSolar states that currently "there are no rules or incentives" to focus attention on siting generation "to improve the efficiency or reliability of the grid… [and] no mechanism through which generators are provided price signals to locate in such a way as to avoid the need for transmission upgrades." Therefore, GridSolar proposes a Smart Grid Coordinator with "responsibility to develop and present non-transmission alternatives to the Commission for consideration alongside transmission solutions presented by the utilities." (GridSolar, pp. 21-22).

In the future, GridSolar expects that smart grid will enable the use of distributed generation resources to meet grid-reliability demands. GridSolar explains that this capability, at present, is limited to central station generation resources. (GridSolar, pp. 22-23). GridSolar anticipates planners using geographically targeted distributed generation and other resources to "obviate the need to build additional peak transmission *and* generation." (GridSolar, p. 23, emphasis in original). GridSolar believes opportunities exist for NTA solutions to avoid costs at all levels of the system, "potentially saving ratepayers billions of dollars in capital costs over the next decade." (GridSolar, p. 23). GridSolar includes these technologies in its list of NTA generation resources solutions: solar photovoltaics, biomass and combined heat and power, back-up generation (BUGs), and battery storage. (GridSolar, pp. 24-27). GridSolar provides a summary of examples – from California, Colorado, Hawaii, Michigan, Nevada, North Carolina, Texas, and West Virginia – where distributed generation is already being used or is planned for use "in lieu of new transmission capacity." (GridSolar, pp. 30-33).

E. Consumer End Use

BHE describes its plans to present to customers, through the Company's website, smart meter hourly usage data and "usage patterns in near real time." The Company briefly describes the capabilities of smart meter hourly data for supporting dynamic pricing, including time-of-use (TOU), real-time pricing (RTP), and critical peak pricing. BHE says it will deploy a limited number of home area networks (HANs) "in 2011, in conjunction with a limited customer short-term dynamic-pricing trial, in order to test how HAN equipment will operate with our AMI system." (BHE, p. 16).

For the future, BHE describes in-home devices (IHDs) and smart thermostats "which are designed to work with whole-house air conditioning systems… to react to price signals by adjusting the cooling settings." The Company anticipates using the ZigBee communications protocol, making such devices as IHDs, smart thermostats, and ZigBee-enabled smart meters available at a total cost of $400 or less per customer. (BHE, p. 16)

BHE also mentions and briefly describes future appliances and vehicle-to-grid (V2G) electric vehicles and charging systems, designed to integrate with smart grid capabilities. No cost or benefit information is included. (BHE, p. 17).

BHE indicates that having an entity other than the utility controlling end-use devices would necessitate duplicate efforts and costs, and that inserting "third parties" into these functions "will increase the handoffs, complexity, and potential failure points… ." (BHE, pp. 17-18). BHE says:

> A smart grid coordinator would need to have access to the controlling software that sends signals to demand-response devices to cycle load off and on, and to the software needed to send pricing alerts to HAN systems and IHD devices in the homes. These systems need to be connected to the ISO pricing systems to relay the real-time pricing changes on an hourly or sub-hourly level, as well as to receive instructions for demand-response actions. The existing utilities system operators can coordinate ISO commands with the utility operators of these business systems. The utilities already own the infrastructure necessary to operate most of these systems, as they are a part of, or integrated with their Smart Meter systems. (BHE, p. 17).

CMP says it already has "smart technologies and the related systems" for customers to take advantage of demand-response energy rates, load-control devices, and net metering. The Company says that "these systems are not widely in use but are contemplated to be fully marketed and used across the CMP service territory." The Company's active load management (A-LM) rate is available only for the control of electric heating systems and electric water heaters. (CMP, p. 28).

CMP says that its smart meters, coupled with demand response – including both direct load control with customer incentives and time-of-use pricing – will allow customers to better control their bills. (CMP, pp. 22-23).

For the future, CMP plans to complete installation of AMI for all customers "by the second quarter of 2012." Then, "CMP expects that the Commission can authorize demand-response rates as a standard program to all customers." In addition, CMP says it expects competitive energy suppliers "to expand their use of time-sensitive demand-response rates." (CMP, p. 29).

CMP says it will provide customers access to a web portal "that will provide day-behind displays of energy use." CMP also anticipates that customers will have access to in-home displays and that real-time display devices will be enabled. But the Company does not explain who will make those devices available to consumers or how much they will cost. (CMP, p. 30).

CMP explains:

> Customers could use this information to monitor consumption when they are away from home, and receive alerts when consumption rises above preset warning thresholds. Such increases could signal an appliance malfunction that the customer could then address by summoning a maintenance call to their premises. Avoiding these malfunctions could result in direct conservation savings. The real-time display portal differs from an in home display in that it is a portable device that can operate outside the customer dwelling. (CMP, p. 30).

CMP also mentions voltage monitoring systems as a future smart grid technology benefitting consumers. With voltage-monitoring capabilities integrated in its AMI meters, the Company says voltage can be continuously monitored and alarms sent "when voltage sags or swells outside of acceptable limits." CMP also says it could be possible to practice conservation voltage reduction, reducing costs while maintaining "acceptable voltage to all customers." (CMP, p. 30).[18]

GridSolar notes that the existing and near-term deployments are prerequisites for dynamic pricing and demand response, but GridSolar observes that the relevant "tariffs, demand-response programs, or other system changes associated with the Smart Grid" are not yet in existence. GridSolar also notes that the ISO-NE Day Ahead and Forward Capacity markets for demand resources relate only to the bulk electrical system (BES), and thus do not address opportunities for resources "on the non-BES part of the grid" to contribute "to simultaneously solve reliability needs and transmission constraints… ." (GridSolar, p. 35).

For the future, GridSolar expects dynamic pricing and demand-response options for consumers. GridSolar provides examples of programs and evaluation results from other jurisdictions. (GridSolar, pp. 36-44). GridSolar recommends that these functions not be provided by utilities, though. GridSolar states:

> All activities on the customer side of the meter should be undertaken by non-utility third parties, such as retail suppliers, ESCOs and Efficiency Maine. Utilities, ISO-NE and the smart grid coordinator can identify opportunities for generation, storage and demand response and even pinpoint locations and time of use for the most cost-effective solutions, but, consistent with utility restructuring in Maine, these entities should not be providers of these services and technologies. (GridSolar, p. 45).

Thus, GridSolar believes that a Smart Grid Coordinator should be assigned the roles of:

> Monitoring conditions on all components of the electric grid (generation, transmission and energy use); Management and dispatch of smart grid resources (including distributed generation, storage, and demand response) for reliability purposes; Development of non-transmission alternatives to address grid reliability requirements while also reducing costs, rates, energy use, and emissions; Implementation of programs designed to facilitate development of new energy services markets capable of providing smart grid applications; and Management of third party access to the smart grid and smart grid functions. (GridSolar, pp. 45-46).

GridSolar elaborates:

> The smart grid coordinator should not own or have any financial interest in any distributed generation resources… . Instead, it should enter into contracts with the owners of these resources that permit the smart grid coordinator to control or manage these resources to ensure grid reliability. These contracts must be designed to ensure that the control or management of these resources is completely independent of wholesale energy markets and control or management is permitted only in response to well-defined and prescribed conditions on the electric grid. (GridSolar, p. 46).

GridSolar proposes that the Smart Grid Coordinator be designated "as a separate utility as authorized by 35-A M.R.S.A §§ 102(13) and 3143(5)." (GridSolar, p. 47). GridSolar recommends that the smart grid coordinator "coordinate its efforts with Efficiency Maine… to design and implement programs that target energy efficiency to those locations identified as having a grid reliability need." In addition, GridSolar says the smart grid coordinator should be engaged in "educating the public about the value of a smart electric grid and about how to utilize the capabilities of the smart electric grid to lower electricity costs." (GridSolar, p. 50).

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[18] This function can be construed as producing benefits for consumers, because it can help protect consumer end-use equipment and conceivably help reduce outages. Voltage monitoring and control provides better operational control and operational savings for the T&D system, too. See Table 11.

Unlike the other parties, GridSolar concludes that "there are no incremental costs associated with the establishment of a smart grid coordinator" to develop, implement, operate, and coordinate a smart electric grid. (GridSolar, p. 51).

The OPA consultants note that the consumer electricity market in Maine is "bifurcated" into: (1) a medium and large commercial and industrial segment; and (2) a small commercial and residential mass-market segment. The consultants note that CEPs and CSPs "are actively competing to capture" the first market and thus are more likely to help those customers take advantage of smart grid functions, to help control and manage energy their use. The consultants further note that mass-market customers are not as likely to take "advantage of smart grid enabled functions" and that the mass-market customers might not be served by CEPs and CSPs. (OPA, pp. 7-10).

The OPA notes that Efficiency Maine Trust could be directed by the Commission to engage in demand-response and "efficiency programs and initiatives enabled by smart grid technologies… ." (OPA, p. 1). OPA agrees that "[a] Coordinator may be required to manage customer and third party access" to some smart grid functions. (OPA, p. 26). OPA observes:

> [U]tilities do not have complete credibility in the eyes of some customers and local governmental units. … [A] typical consumer may be inclined to discount or ignore an invitation by a utility to "save money," "reduce energy use," or "help the environment" by participating in a utility-sponsored program. (OPA, p. 29).

The OPA notes, however:

> [E]ven with active motivation and assistance the percentage of mass market customers voluntarily electing to participate in dynamic pricing and other smart grid enabled programs has generally been well less than 10 percent. (OPA, p. 27).

Thus, even with support from Efficiency Maine Trust and a Smart Grid Coordinator, the OPA expects it could prove challenging to achieve widespread participation and capture benefits associated with mass market customers. The OPA further recognizes that a Smart Grid Coordinator could be needed to support electric-vehicle functions. (OPA, p. 30).

IV. Analysis

To summarize smart grid functions and capabilities, Table 1 illustrates (in the columns) the major missions that smart grid is intended to provide and (in the rows) the major smart grid components. The cells include examples of some of the many ways in which a component can help to achieve a mission. Table 1 is not an exhaustive listing, though. As already mentioned, such analysis is complicated because: (a) smart grid visions are continuing to evolve rapidly as new technologies and applications develop; (b) many smart grid components help to achieve multiple missions at various levels of the electric grid; and (c) many smart grid functions could involve multiple actors. As the OPA consultants observe, "[M]ost of the functions do not fall into simple, distinct categories because several different parties could be involved in providing them." (OPA, p. 21).

The TESM *Comments* demonstrate how one smart grid application can involve and affect multiple levels of the utility system. In this instance, the DLR technology operated by the T&D company combines with generation resources like intermittent wind power and possibly dynamic pricing to reflect price variability in generation markets and empowers customers to manage space- and water-heating end uses in a new way, using ETS technology. In some instances, TESM notes that individual ETS heating elements can be switched on and off under direct control based on dispatch signals from the ISO, too. (TESM, p. 3). Thus, the ETS technology is capable of delivering benefits to all four levels of the utility system.

What is important in this inquiry, though, is that some of the missions could prove relatively easy to achieve because they are already well-aligned with the incentives and regulations influencing the action of the parties involved. As a reminder, Maine's electric utility industry structure includes regulated monopoly T&D companies that own and operate both transmission and distribution system equipment. The transmission system and regional wholesale electricity markets, including day-to-day operations, administration, and planning, are directed by the FERC-regulated Independent System Operator of New England (ISO-NE). The distribution system, including rates, conditions, and terms of retail service, are regulated by the Maine Public Utilities Commission. Generation assets are owned and operated by competitive suppliers. Customers receive T&D service from regulated utility companies that each serve a distinct monopoly service territory. Customers receive generation service from a competitive supplier of the customer's choosing.

Table 2 and Table 3 represent a preliminary attempt to identify the smart grid missions and components that are presently well-aligned with various parties' incentives, under current regulations. Note that plus signs in Tables 2 and 3 connote more than just a generally positive disposition. A plus sign means the motivation is thought to be sufficient to ensure the actor's earnest efforts to maximize the benefits gained from using the particular smart grid component. A plus and minus ("+/– ") sign means that a party has mixed motivations, both positive and negative. Blank cells indicate a general lack of incentive.

Some examples of positive motivation for Maine's T&D utilities include improving asset utilization; managing assets to avoid reliability problems; detecting and diagnosing problems early to avoid emergencies; reducing forced outages, preventing cascading outages, and responding quickly (and efficiently) to outages; decreasing congestion and line losses; reducing theft and fraud; improving cash flow; and improving employee productivity. Current incentives for Maine's T&D utilities are generally well-aligned with these objectives, regardless of the utility's existing rate structure. Under CMP's alternative rate plan (ARP), positive motivation is supported by: (a) metrics and penalties associated with poor performance as defined by the Customer Average Interruption Duration Index (CAIDI) and System Average Interruption Frequency Index (SAIFI); (b) assured cost recovery in the ARP for expenditures associated with recovering from outages that result from major storm events; and (c) the profit motive to increase sales and lower production costs. Even under more traditional ratemaking, where each expense is subject to regulatory review, the profit motive generally supports capital investment: Shareholder returns are predicated on capital investments such that the higher the value of approved investments, the larger the total authorized return. This is particularly true for smart grid investments in the transmission system, which are FERC jurisdictional.[19] As in any regulatory area, incremental improvements could be achieved, but these activities for T&D utilities appear to be aligned satisfactorily with existing regulations and incentives.

On the other hand, if smart grid improvements eventually reduce the need for new investments in assets for T&D utilities, the incentive would move in the opposite direction.

Other objectives, however, could prove difficult to achieve because of a current lack of alignment or even misalignment with incentives and regulations. Examples cited in Docket No. 2010-267 include the lack of any marketers presently offering smart grid services to residential consumers (OPA, pp. 7-10) and current T&D company incentives and ISO-NE cost allocation formulas that are thought to be barriers to NTA identification and development (GridSolar, pp. 21-22, 47, 51). TESM *Comments* explain how current rate structures are a barrier to ETS technology and might be altered to enable its wider use (TESM, pp. 4-5).

An historic example of realigning roles in Maine's energy sector is the creation of the Efficiency Maine Trust, chartered with the mission to help customers obtain cost-effective energy efficiency.[20] The presently existing business model for Maine's incumbent electric utilities links profits directly to the quantity of electricity delivered to consumers. An incumbent T&D utility can promote efficiency programs, but there is a potential conflict between the conservation and sales-reduction goals of efficiency programs and the utility's underlying profit motive (York & Kushler, 2011). Arguably, this incentive structure could result in utility-designed and -managed energy-efficiency programs that would not be as efficiently or effectively implemented as would be achieved by a separate entity, like the Efficiency Maine Trust, whose sole purpose is to focus on energy savings.

The analysis in Part IV follows the Final Outline used in soliciting comments in Docket 2010-267, reflecting our analysis of the information presented in each of the four levels of smart grid implementation: (1) Bulk and PTF System; (2) Maine Local T&D System; (3) Generation Resources; and (4) Consumer End Uses. For each of the four levels, these subjects are reviewed:

- Existing Tools: What smart grid tools are available today?
- Future Tools: What smart grid tools are expected in the future?
- Implementation in Maine:
  - How is Maine doing on implementing the existing smart grid tools and paving the way for implementing future tools?
  - What, if anything, is Maine *not* doing about implementation that might otherwise be helpful either now or in the future?
- Barriers:
  - What barriers, if any, might prevent Maine from fully achieving smart grid benefits?
  - What is the potential role of a Smart Grid Coordinator in overcoming those barriers?

The analysis of each level of smart grid implementation also explores in more detail the interests of private parties, their incentives, and the potential for alignment or misalignment with the public interest in promoting, deploying, and operating smart grid technologies.

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[19] FERC responded to a directive in the U.S. Energy Policy Act of 2005 to establish incentives for investments needed to improve the nation's transmission system by authorizing returns on equity (ROEs) in the range of 12-14% for transmission investment. See Snarr, 2010.

[20] The history and administration of Efficiency Maine is reviewed at http://www.efficiencymaine.com/about, retrieved 5 Sep 2011.

Table 1: How Smart Grid Missions Are Advanced by Major Smart Grid Components

Missions→ ↓Components↓	Increase efficiency in utility operations	Increase system security, reliability, and power quality	Reduce fossil fuel use and emissions	Enhance customer choices, including rate offerings	Induce customers to modifying usage patterns to produce system benefits	Improve utility planning quality and accuracy	Develop the economy and grow jobs
Transmission Enhancement	Decrease congestion and line losses	Reduce forced outages Prevent cascading outages	Facilitate integrating wind and solar	Minimize bottlenecks to improve market efficiency	Match loads with output of non-dispatchable generation	Allow better matching of supply and demand	Expand green power portfolio & supply diversity
Distribution Automation	Reduce system losses Improve asset utilization	Enable dynamic optimizing	Improve asset use efficiency		Facilitate smart charging of electric vehicles	Produce disaggregated data for improved asset utilization	Reduce system losses Improve asset use efficiency
Distributed Resources	Integrate variable output generation; storage	Enable smart microgrid operations	Integrate variable output generation; storage	Enable more green power choices	Optimize use of wind and solar	Improve short-term forecasting and scheduling	Diversify supply
AMI	Enable operational efficiencies; efficient outage management	Detect and diagnose problems early Respond quickly to outages	Minimize vehicle miles driven for meter reading and customer service	Enable variable rates that better reflect market prices	Make possible the use of in-premise displays and smart thermostats	Provide detailed knowledge of service territory loads and growth	Reduce theft and fraud Improve cash flow
System-Wide Information & Communications Integration	Improve forecasting	Manage assets to avoid reliability problems	Integrate weather & air quality data	Broadcast real-time prices to induce demand response	Utilize web portals and in-premise displays to communicate with customers	Get the right data to the right people in time to be helpful	Provide accurate price signals Support timely bill settlement
Utility Personnel Education and Training	Improve employee productivity	Detect problems early to avoid emergencies				Make sure utility workers are ready to use the best available data	
Meaningful Demand-Response Capabilities	Enable efficient EV charging	Shift loads and reduce peaks	Improve environmental dispatch	Shift loads and reduce peaks to decrease bills	Foster "set it and forget it" convenience	Supply detailed data on demand response	Put downward pressure on supply costs
Customer-Side Systems	Foster "set it and forget it" convenience	Support preventive maintenance	Advance efficient energy use and conservation	Make possible new products and services	Improve HVAC and appliance management	Present detailed data on usage patterns	Put downward pressure on prices and bills
Customer Education and Training			Increase end-use efficiency through smarter customer choices	Promote new rate offerings to help customers achieve cost savings	Teach customers about load management and demand response		

Source: Stanton, 2011, p. 37. Table adapted from *Understanding the Benefits of the Smart Grid,* June 2010, National Energy Technology Laboratory, DOE/NETL-2010/1413, www.netl.doe.gov/smartgrid/, incorporating additional information from Ashley Brown and Roya Salter, September 2010, *Smart Grid Issues in State Law and Regulation*, Galvin Electricity Initiative, www.galvinpower.org.

Table 2: Existing Incentive Alignments Among Major Actors and Smart Grid Missions

Missions→ ↓Actors↓	Increase efficiency in utility operations	Increase system security, reliability, and power quality	Reduce fossil fuel use and emissions	Enhance customer choices, including rate offerings	Induce customers to produce system benefits by modifying usage patterns	Improve utility planning quality and accuracy	Develop the economy and grow jobs
ISO-NE	+	+				+	
MLCC	+	+				+	
T&D Companies	+	+		+	+	+	+
CEPs	+	+	+/–	+	+		+
CSPs		+	+	+	+		+
EMT			+	+	+		+
TSPs			+/–				+
Consumers				+/–	+/–		+

Table 3: Existing Incentive Alignments Among Major Actors and Smart Grid Components

Actors→ ↓Components↓	ISO-NE	MLCC	T&D Companies	CEPs	CSPs	EMT	TSPs	Consumers
Transmission Enhancement	+	+	+	+				
Distribution Automation			+					
Distributed Resources			+/–			?	+	+
AMI	+	+	+	+	+	+	+	?
System-Wide Information & Communications Integration	+	+	+	?	?	?	?	?
Utility Personnel Education and Training			+	+				
Meaningful Demand-Response Capabilities			+/–		+	+	?	?
Customer-Side Systems			+	+	+	+	+	+
Customer Education and Training			+	+	+	+	+	+

In the four sections that follow, Tables 4 through 11 summarize the responses of parties to the questions presented in the Final Outline developed for Docket 2010-267 (October 27, 2010, Procedural Order, Appendix One). Each pair of tables summarizes responses for one of the four smart grid levels: (1) Maine's Bulk and Primary Transmission Feeder (PTF) Power System; (2) Maine's Local T&D system; (3) Generation Resources; and (4) Consumer End Use. In each pair, the first table includes responses about the smart grid technologies already in place or actively being deployed, while the second table lists smart grid technologies and systems that the parties expect to be available in the future. Where these Tables include blank cells, it means that the Docket record does not clearly identify or describe achievable benefits for one or more of the identified participants, benefits are not expected to accrue to one or more parties, or both.

A. Maine's Bulk and Primary Transmission Feeder (PTF) power system

In this discussion, smart grid applications for Maine's bulk electric system (BES) are defined as including two-way communications, metering, and controls, including SCADA, for BES resources. The BES in Maine is essentially all the transmission equipment at greater than 100 kilovolts, regulated by FERC and subject to NERC security and reliability standards and ISO-NE for day-to-day operations. Tables 4 and 5 summarize the party's answers about the bulk and PTF power system. The technologies identified generally provide benefits for the owners and operators of the transmission system, which include ISO-NE, MLCC, and the T&D Utilities.

BHE identifies the basic system benefits it expects from each technology, but does not explain how it works to reduce ratepayer costs. BHE does not provide any explicit benefit or cost data for these technologies. (BHE, pp. 2-4). CMP reports the systems will allow the Company to "reduce criteria violations… which can potentially amounting [SIC] to millions of dollars" (CMP, p. 13).

- **Existing Tools: What smart grid tools are available today?**

Table 4 summarizes the existing smart grid equipment and what Maine's T&D companies are already in the process of installing. Both BHE and CMP are in the process of deploying: two-way communications, metering and control systems and SCADA.

BHE lists these components, which work in concert with SCADA to provide data and operational controls: remote terminal units (RTUs), microprocessor based relaying, programmable logic controllers (PLCs), communication multiplexers, digital fault controllers (DFRs), sequence of events recorders (SERs), and synchrophasors (BHE, p. 4). BHE says these technologies provide "[c]ontinuous monitoring…[and] the means to control the power system as needed for reliability" (BHE, p. 3).

CMP also reports installing a transmission security management (TSM) system. CMP reports:

> This system will provide greater reliability, efficiency, flexibility in operation, and safety… preventative maintenance, system wide analysis and modeling, remote system visibility and restoration. This will also enable more system balancing to be available, especially energy storage and demand-response resources. … Supervisory control allows the CMP EMS to constantly monitor power flows and to alert NERC certified operators of out-of-limit operating conditions or contingencies. In this way, grid operators can better ensure safe and reliable grid operation under all operating conditions, including maintenance activities and emergencies. In addition, the bulk power grid makes use of relaying equipment and a frequency-trip system to increase reliability and avoid major outages that result from contingencies (e.g., line, generator, or neighboring system outages). (CMP, p. 13).

- **Future Tools: What smart grid tools are expected in the future?**

As shown in Table 5, the parties list few smart grid tools to be deployed for the BES in the future. BHE reports the company is already "involved with the ISO-NE Synchrophasor Infrastructure and Data Utilization Project" (BHE, p. 4). In addition to the technologies listed in Table 5, CMP discusses the forthcoming FERC and NERC smart grid standards, and new standards for under-frequency load shedding and critical infrastructure protection (CMP, pp. 17-18). CMP states, "To implement these standards, extraordinary efforts are needed" (CMP, p. 17).[21]

- **Implementation in Maine:**
    - **How is Maine doing on implementing the existing smart grid tools and paving the way for implementing future tools?**

Under current regulations, Maine's T&D companies are responsible for operating the BES under ISO-NE direction.[22] BHE, CMP, GridSolar, and OPA all agree that – with or without the inclusion of a smart grid coordinator – the major responsibilities for implementing and operating smart grid components for the BES and Maine Local T&D will continue to reside with the T&D companies (BHE, pp. 10, 15, 17-18; CMP, pp. 2, 12, 25-27; GridSolar, pp. 12, 20-21; and OPA, pp. 3, 18).

Table 4: Technologies, Functions and Achievable Benefits for Bulk and PTF Power System from Smart Grid Assets and Activities Already In Place or In Deployment

Technologies, Functions	**Achievable Benefits**		
	ISO-NE	**Maine Local Control Center (MLCC)**	**T&D Utility**
Two-way communications, metering, and control system. Includes an energy management system for the Maine Bulk Electric System and Maine Local Control Center.	Provides "…greater reliability, efficiency, flexibility in operation, and safety… preventive maintenance, system wide analysis and modeling, remote system visibility and restoration. … [Enables] more system balancing…, especially [of] energy storage and demand-response resources (CMP, pp. 13-14).		
Supervisory control (SCADA). Integrates remote terminal units, microprocessor based relaying, programmable logic controllers, communication multiplexers, digital fault recorders, sequence of events recorders, and synchrophasors (BHE, pp. 1-2).	Supervisory control allows the CMP EMS to constantly monitor power flows and alert NERC certified operators of out-of-limit operating conditions or contingencies. In this way, grid operators can better ensure safe and reliable grid operation under all operating conditions, including maintenance activities and emergencies. In addition, the bulk power grid makes use of relaying equipment and a frequency-trip system to increase reliability and avoid major outages that result from contingencies (e.g., line, generator, or neighboring system outages) (CMP, p. 13).		
Transmission security management (TSM). Includes a "state estimator" and "contingency analysis module." Incorporates SCADA capabilities.	To "protect integrity and efficiently operate… ." For "grid network analysis and contingency analysis… identifying and analyzing potential operating problems as well as formulating various remedial strategies… ." (CMP, p. 14).		
Note: SCADA was identified by multiple parties, as applicable to both the Bulk and PTF and Maine Local T&D systems (see also Table 7).			

[21] BHE discusses the new FERC and NERC cyber-security and critical infrastructure protection standards in the context of the Maine Local T&D system (BHE, pp. 11-12).
[22] CMP discusses this issue in its introduction (CMP, pp. 2, 12), in the context of the Maine Local T&D System (CMP, p. 25), and Generation Resources (CMP, p. 27). The similar BHE discussion of operational responsibilities is presented in the BHE review of the Maine Local T&D System (BHE, pp. 14-15).

The utility, with proper regulation, will have the motivation to optimize the use of its existing and new T&D resources. Both BHE and CMP provide assurances of their interest in doing so (BHE, pp.13-15; CMP, pp. 24, 28).

Table 5: Technologies, Functions and Achievable Benefits for Bulk and PTF Power System from Future Smart Grid Technologies and Systems

<table>
<tr><th rowspan="2">Technologies, Functions</th><th colspan="3">Achievable Benefits</th></tr>
<tr><th>ISO-NE</th><th>Maine Local Control Center (MLCC)</th><th>T&D Company</th></tr>
<tr><td>Synchrophasors (BHE, pp. 4-5). Includes “Power donut” monitoring devices.</td><td colspan="3">“[I]ncreased grid efficiency, reduced congestion costs, and less potential for generation curtailments, including curtailments of variable wind and solar generation.” Dynamic line ratings (DLR) to increase capacity limits and improve utilization of existing lines (CMP, p. 18). Improved planning and operational system analyses (GridSolar, pp. 13, 28-29). Planning for non-transmission alternatives (GridSolar, p. 47).</td></tr>
<tr><td>Flywheel storage and bulk battery storage.</td><td colspan="3">Frequency regulation (BHE, p. 5).</td></tr>
<tr><td colspan="4">Notes: Synchrophasors were identified by multiple parties as applicable to both the Bulk and PTF and Maine Local T&D systems. Flywheels and bulk battery storage can provide additional benefits, but BHE lists only frequency regulation as a benefit for the BES and PTF system. Storage is also included in the discussion of Generation Resources (see Tables 8 and 9).</td></tr>
</table>

- **What, if anything, is Maine *not* doing about implementation that might be helpful either now or in the future?**

GridSolar and OPA are both concerned that current incentives and regulations will not sufficiently encourage utilities to apply smart grid capabilities to maximum advantage for ratepayers (GridSolar, pp. 17-23, 45-46, 50; OPA, pp. 3, 13, 19, 36).

GridSolar, in its February 16, 2010 Responses to Data Requests, discusses the prospect of establishing locational capacity prices, which has been somewhat explored by ISO-NE but not yet widely implemented. The implication is that locational capacity prices would signal to developers the profitable opportunities to install and operate distributed resources in particular places. That is the essence of NTA solutions. Locational installed capacity was implemented in Connecticut for a time, but the costs were not socialized, and a transmission solution eventually subsumed the NTAs. Although another potential limitation is a capped hourly market price, which acts as a limiter on dynamic pricing, socialized cost recovery of locational capacity needs could go a long way towards fostering NTA solutions. (Responses of GridSolar to Data Requests, Docket No. 2010-267, Feb. 16, 2010, pp. 12, 14).

If locational capacity needs were auctioned in the forward market, with forward prices derived from the capital costs of the alternative local transmission solution, then there might be no need for an NTA coordinator: Transmission and NTA solutions would compete with one another through the forward capacity market mechanism. However, it is unclear how, when, and ultimately if such a modification to the ISO-NE forward capacity market might take place, and relying on a market solution to meet reliability needs that are now addressed through long-term planning studies would add uncertainty. Furthermore, NTA coordinator designation as a monopoly would be unlikely under locational forward capacity market modifications, given the goal of a market structure designed to elicit multiple, competing NTA solutions.

This discussion highlights what is likely the most important gap in smart grid planning and deployment for the BES: implementation of NTA solutions. Maine law allows T&D utilities to own generation for the reliable operation of the transmission system (Title 35-A §3204(6)),[23] but since the onset of generation divestiture Maine's T&D utilities have not implemented any new generation-based NTA solutions (June 7, 2011 *Transcript of Technical Conference* in Docket No. 2010-267, pp. 127-131). This lack of implementation is to be expected, as it aligns with a business model premised upon electricity delivery through transmission and distribution networks. T&D companies might not be fully engaged in identifying and implementing NTA solutions. That can be because of any combination of insufficient incentives, lack of familiarity with, and lack of trust in the reliability and dispatchability of NTA options. T&D companies will question whether NTA options will work as promised and continue working, long term. (GridSolar, pp. 21-23).

- **Barriers:**
    - **What barriers, if any, might prevent Maine from fully achieving smart grid benefits?**

In particular for the BES, the question is whether T&D companies will maximize smart grid operations if it leads to diminishing total investment and a shrinking ratebase. In the near term, T&D companies have the impetus to invest in smart grid components. That is true as long as the companies believe the Commission will find such investments to be both prudent and aligned with Maine regulations and policy. Investments thus approved by the Commission add to ratebase and generally increase a utility company's opportunity to earn profits. A related question, though, is what happens in the long run if smart grid capabilities reduce the need for transmission system investment. Would a T&D company actively pursue smart grid applications if the end-game will be a smaller role for the company in the electricity market? Would T&D company managers apply the principle credited to former Apple CEO Steve Jobs, who told one reporter, "If anybody's going to make our products obsolete, I want it to be us" (Levy, 2011)?

- **Changing transmission cost allocation and forward capacity market rules**

A related question is whether existing price structures are designed appropriately to elicit an economically efficient outcome. As GridSolar discusses in its February 14, 2010 *Responses to Data Requests*, one clearly apparent issue is the transmission cost allocation mechanism presently in place in New England (*Responses of GridSolar to Data Requests*, Docket No. 2010-267, Feb. 14, 2010, p 12). Maine ratepayers bear only about 8% of the costs of BES transmission projects approved through the ISO-NE planning process, whereas the costs of an NTA solution would fall entirely on Maine ratepayers.

Thinking of NTA solutions as generation-like, changes would include developing locational forward capacity market rules, as discussed above, thus producing better, more accurate pricing signals and more serious consideration of NTAs. Alternatively, a top-down planning approach employing system studies to identify future transmission system needs could also solicit and incorporate NTA solutions. In cases where an NTA solution would be most cost-effective, the resources utilized to provide the NTA might be designated and thereby compensated in much the same way as reliability must-run generation; that is, as reliability must-run distributed generation, storage, or demand response.

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[23] Maine Public Law, Chapter 32. (1997). http://www.mainelegislature.org/legis/statutes/35-A/title35-Asec3204.html. Section 3204(6) states:

> **Generation assets permitted.** On or after March 1, 2000, notwithstanding any other provision in this chapter, the commission may allow an investor-owned transmission and distribution utility to own, have a financial interest in or otherwise control generation and generation-related assets to the extent that the commission finds that ownership, interest or control is necessary for the utility to perform its obligations as a transmission and distribution utility in an efficient manner.

This latter conception of reliability must-run NTAs begins to look more transmission-like as it utilizes transmission planning studies as opposed to forward capacity markets as the driver for provisioning NTA resources. This solution, outside of the forward capacity market, requires transmission cost allocation that treats NTA solutions as equal and competing proposals to transmission solutions. An SGC as envisioned by GridSolar – that is, a franchised monopoly focusing on providing NTA resources for grid reliability – would not directly participate in the forward capacity market. That would "preserve the independence between the grid reliability function and the operations of wholesale markets." (GridSolar, p. 49). As such, GridSolar's proposed SGC concept is more transmission-planning based: The SGC acts as broker for distributed NTA resources owned by other entities, and interacts on their behalf with the local incumbent T&D utility and ISO-NE planning and operations. Alternatively, if ISO-NE transmission rules were properly revised, NTA resources might be encouraged, perhaps negating the need for an SGC or, more specifically, an NTA Coordinator (NTAC).

It makes sense that GridSolar's SGC model could develop if the cost-allocation rules change. An SCG would be a knowledgeable, specialized entity working on effectively incorporating NTAs into the ISO-NE BES planning process.

As an aside, in GridSolar's particular model of an SGC it is unclear whether distributed generation contracted to provide grid reliability as part of an NTA solution should also be able to bid into the forward capacity market. GridSolar maintains that it should. (GridSolar, p. 49). To make this model work, the grid-reliability function would be construed as a separate and additional value produced by a particular generation resource by virtue of its geographic location.

- **Consistent analytic techniques to compare transmission and NTA solutions**

The hybrid nature of NTA solutions (that is, part generation-like and part transmission-like) begs the question of how to ensure equivalent analysis and modeling for both transmission and NTA solutions. To properly design changes to rules and regulations, to consider whether there is a need for an SGC, and to determine the relative costs and benefits of transmission and NTA solutions, an understanding of how to properly compare the cost and benefits of these alternatives is needed. This understanding is needed whether or not an SGC exists: For instance, it is pertinent to evaluating competing transmission and NTA proposals in the Certificate of Public Convenience and Necessity (CPCN) process.

One area of possible misunderstanding because of the potential complexity is the time scales utilized in comparing solutions. In comparing competing proposals it is essential that total costs are accounted for over equivalent time scales. The effects of demand-response and real-time pricing should be accounted for in transmission planning (i.e., in projecting future system peak load). The optimum solution for any remaining transmission needs is likely to be the one, whether transmission or NTA, that provides the least-cost solution over equivalent lifetimes of the potential asset alternatives. Therefore an NTA solution must obviate the need for particular transmission system investments for a sufficient length of time. Otherwise Maine ratepayers would eventually have to pay their share of the same transmission investments the NTA intends to avoid.

The life expectancy of a transmission project can be upwards of 50 years or more, while an NTA solution might involve a series of contracts for distributed resources, that each last five years or less. Merely projecting the relative costs and benefits over a 10- or 15-year planning horizon will not adequately reflect the long-term benefits of a transmission solution. An appropriate discount rate must also be established to account for the time value of money and the differences in the timing of costs and benefits for various solutions.

Determining the optimal timing of transmission investments has been investigated in the context of growing electricity loads in the developing world. A deterministic spreadsheet model developed by

Schramm (1989) outlines how to calculate the optimal least-cost solution between transmission and NTAs. Under growing loads, transmission investments tend to be more cost-effective once load demands reach a certain level. This level specifically occurs when the marginal gains from the investment in transmission equal the marginal costs of delaying the investment. The analysis provides a means of determining when distributed, non-interconnected electricity generators (assumed to be more costly than bulk power generation) should be displaced by investment in transmission infrastructure that connects the rural area to the interconnected bulk transmission grid.

This deterministic model is equally applicable to determining investment in NTA resources, albeit in the opposite direction. That is, the potential scale economies in manufacturing and deploying distributed electricity resources, combined with the better information exchange enabled by smart grid, will sometimes mean that distributed resources can obviate or at least significantly delay the need for interconnected bulk electricity transmission between large centralized generators. This result will increase in frequency, duration, and geographical spread of NTA opportunities as distributed generation resources and electricity storage continue to decline in price due to continuing technological improvements, economies of scale driven by mass production, and smart grid's ability to greatly reduce transaction costs (see Keisling, 2010 and Shum, 2010).

While a deterministic model provides an understandable, straightforward approach to transmission investment analysis, such a model is predicated on perfect foresight, where the forecasted load growth is realized at the point in time predicted.

To take the uncertainty of future growth of load demand into account, an option-valuation approach can be utilized (Martzoukos and Teplitz-Sembitzky, 1992). An option is an insurance against an uncertain future. When applied to transmission investment, the option value model attempts to determine the right time to exercise the option to invest in transmission. The option-value approach indicates that accounting for uncertainty will delay the optimal time of investment in transmission relative to what a deterministic approach would indicate. However, the complexity and number of assumptions behind such an option value analysis may preclude the application of such a model. It is worth noting, though, that a deterministic model will always underestimate the optimal time to switch from an NTA to a transmission solution, giving an inherent buffer in the decision-making timeline. That is, a small delay in constructing a transmission solution will often end up being more economical than a deterministic model indicates.

In addition, though, many of the measures identified in any search for an NTA solution will be cost-effective in their own right. Energy-efficiency, demand-response, load-management, and other distributed resources sometimes including distributed generation, independent of and in addition to their potential role in helping to solve any particular NTA need, will often be cost-effective when analyzed solely on the basis of consumer avoided costs, without any consideration of future avoided transmission system costs. That trend will facilitate the marketing and implementation of the distributed resources, but it can complicate NTA option-value modeling because of uncertainty in the breadth and depth of the market response, absent any explicit process that identifies, selects, and seeks to implement an NTA solution.

- **What is the potential role of a Smart Grid Coordinator in overcoming those barriers?**

Would an SGC, changes to existing regulations, or a combination of both be best suited to solving this NTA gap in Maine's present electricity market? In many ways, NTA solutions raise the same kinds of concerns about the role of energy-efficiency solutions in least-cost utility planning and action that led to establishing Efficiency Maine Trust. It follows that an independent entity with an unambiguous motivation to maximize applications of NTA options might also be needed in this case.

Irrespective of the existence or role of an SGC, establishing a framework to enable NTA options to achieve their full potential will require changes to transmission planning rules and cost-allocation practices on the BES, as discussed above. However, an SGC (perhaps more appropriately named "NTA Coordinator" or NTAC) would likely be motivated to actively pursue such regional and national policy changes; perhaps helping to instigate better and earlier solutions. The possible changes can be construed as being either market based (generation-like) or planning based (transmission-like), given the hybrid nature of NTAs and the existing transmission and market rules in New England.

This role is one aspect of the GridSolar vision of the SGC, as developer of NTA solutions (GridSolar, pp. 45-46). It is not clear, though, whether establishing an SGC and assigning it the role of NTA promoter is either necessary or by itself sufficient to achieve the goals GridSolar envisions. It is also questionable whether an SGC, if established, should be devised as an exclusive monopoly providing NTA resources.

Broaching the second concern first, designating a monopoly coordinator would put this entity on more equal footing to the incumbent T&D utility, having been given a geographic franchise area. Theoretically, though, open competitive solicitations for NTA solutions would best attract the most creative and least expensive solutions. But, given the costs of modeling NTA options, having only two designated entities working with the same transmission system model – a T&D utility and an SGC for that utility's service territory – could be the best approach to the initial design of transmission and non-transmission solutions. Also, a monopolistic entity in the form of a regulated utility with specific contracts with or ownership of NTA resources would provide more assurance throughout the jurisdictional chain of electric transmission planning. The subsequent increase in confidence of the viability of NTA solutions would help to put such proposed solutions on more equal footing with transmission solutions. The perceived lack of direct control of NTA resources, whether deserved or not, increases uncertainty and thus reduces the perceived value of an NTA solution.

Establishing an SGC as a monopolistic franchise could reduce competition, though. As CMP points out, the presence of a monopoly SGC entity might dissuade other firms from developing and bidding potential NTA solutions. (CMP, p. 25). VCharge is an energy management services company focused on utilizing sophisticated communications to control demand response rapidly. This company is presently participating in ISO-NE's voltage regulation market. (TESM, pp. 2-3). Viridity Energy and EnerNOC have developed as entities bidding demand resources and distributed generation into wholesale energy markets. If an SGC is granted a monopoly franchise, even if only temporarily, its activities should be restricted so it does not assume functions that are or easily could be served by competitive markets.

These concerns might be alleviated by enabling a monopoly SGC to identify a general NTA opportunity. The SGC would then solicit competitive supplier proposals for specific NTA resources, and then contract with the preferred resources to ensure the NTA fulfills its requirements. GridSolar proposes this role for an SGC (GridSolar, pp. 45-46). A remaining question in this structure, though, is what entities should be parties to NTA resources contracts. Would dispatch and operations of the NTA be the responsibility of the SGC, the T&D utility, or some hybrid involving both? And is the task of identifying NTA opportunities broad and complex enough, requiring significant coordination with the incumbent T&D utility, to call for a single NTA coordinator for each utility service territory? The information filed by parties in this case does not provide enough information to answer these questions definitively.

B. Maine's Local T&D system

- **Existing tools: What smart grid tools are available today?**

Table 6 briefly summarizes the information provided about smart grid assets already in place or in deployment for the Maine Local T&D System. BHE lists its GIS system, AMI, AMI-equipped mobile trailers, reconnect collars, security hardware and software, upgraded substation equipment, meter data management system (MDMS), and web portals (BHE, pp. 6-8).

Table 6: Technologies, Functions and Achievable Benefits for Maine Local T&D System from Smart Grid Assets and Activities Already In Place or In Deployment

<table>
<tr><th rowspan="2">Technologies, Functions</th><th colspan="3">Achievable Benefits</th></tr>
<tr><th>ISO-NE</th><th>Maine Local Control Center (MLCC)</th><th>T&D Company</th></tr>
<tr><td>Integrated voltage and VAR control.</td><td>Confirm demand- response and storage availability… used as a dispatchable resource in ISO-NE where it can qualify as capacity (GridSolar, pp. 19-20).</td><td></td><td>Optimize the distribution grid, maximize feeder capacity, and reduce line losses (CMP, p. 20).</td></tr>
<tr><td>Voltage reduction capability and under-frequency load-shed capability.</td><td>Meets ISO-NE Standards for Voltage Reduction and Load Shed Capability (CMP, p. 20; GridSolar, p. 15).</td><td></td><td></td></tr>
<tr><td>Geographic Information Systems (GIS).</td><td></td><td colspan="2">Applications include: facility management, distribution analysis, work order design, outage management, and resolving voltage quality issues. (BHE, pp. 6, 8).</td></tr>
<tr><td>AMI, including: remote connect & disconnect devices; mobile AMI trailers; meter data management system (MDMS).</td><td></td><td colspan="2">[U]pgrading substation communications equipment to increase speed and throughput of commands… . [A]dding software to improve outage management… integrates with… GIS… . (BHE, pp. 6-7, 9-10; GridSolar, p. 16).</td></tr>
<tr><td>Security hardware and software (BHE, p. 7; GridSolar, p. 20).</td><td></td><td></td><td>Improved security.</td></tr>
<tr><td colspan="4">Note: CMP lists voltage reduction capability in its discussion of future Consumer End-Use Benefits. See Table 11.</td></tr>
</table>

CMP lists its AMI system. CMP notes its AMI will "provide better diagnostics that will enable fewer outages, … [enable] [i]ntegrated voltage and VAR control… to optimize the distribution grid, maximize feeder capacity, and reduce losses… [and] confirm demand-response and storage availability" (CMP, p. 20). CMP says its Maine Local T&D System smart grid tools will help achieve unspecified "operational and maintenance savings" (CMP, p. 21). CMP also explains:

> These capabilities also reduce ratepayers' cost by reducing load when generation is unavailable. If these functions were not performed, system collapse or blackout may occur incurring millions of dollars in lost opportunities for businesses. (CMP, p. 21).

- **Future tools: What smart grid tools are expected in the future?**

BHE reports that its revenue protection software will utilize AMI system capabilities to "improve theft-of-service detection, enable subsequent revenue recovery, and ultimately reduce theft on the system." BHE notes this will benefit all customers. (BHE, p. 12). BHE explains how demand-response units (DRUs) could be installed to enable load-shedding control for specific 30-amp relays. This function could allow control for water heaters, central air handling units, air conditioners, or pool pumps. (BHE, p. 13).

BHE also reviews how the company's meter data management system (MDMS) could integrate with the Company's AMI capabilities to offer improved, more accurate distribution load analysis. The Company says this capability will allow easier identification of distribution-system problem areas. (BHE, p. 13).

CMP describes its "effort to confirm compatibility of each intelligent device with the AMI communications infrastructure and to integrate each type of device into CMP's EMS." CMP states:

> Once the proof-of-concept integration is completed, CMP will be able to expand its Smart Grid and Distribution Automation capabilities across the entire distribution system as prudency warrants. CMP will install the latest Smart Grid technology… to achieve "smart" operations, demand response, customer metering and billing services, voltage control, and underfrequency load shedding. (CMP, pp. 22-23).

The future tools for the Maine Local T&D System are summarized in Table 7.

- **Implementation in Maine:**
  - **How is Maine doing on implementing the existing smart grid tools and paving the way for implementing future tools?**

Both BHE and CMP report being well on their way to implementing end-to-end smart grid solutions, including full AMI systems with smart meters at all customer locations, wide-area communications networks with two-way communications capabilities including SCADA and distribution management systems (DMS) throughout their local T&D systems, integration with GIS systems, revenue protection software, and cyber security to meet emerging NIST standards.

T&D companies will be motivated to invest in AMI infrastructure by virtue of being able to earn a return of and return on those investments. T&D utilities are motivated to implement SCADA control devices because the data improves outage management and operational functionality. T&D companies will be able to reduce labor costs by dispatching operating instructions to equipment remotely rather than physically visiting a substation. T&D utilities are also motivated to install AMI meters, communications equipment, and data management systems, to the extent that such facilities can reduce labor costs (associated with meter reading and customer service) and improve outage management.

AMI represents a multitude of hardware, software, and communications technologies, though. Synchrophasors, power donuts, dynamic line ratings, and voltage and VAR controls all provide means to maximize transmission and distribution feeder capacity and reduce transmission and distribution line losses due to congestion. These tools are applicable to both the BES and Maine Local T&D system levels. They are discussed here because both BHE and CMP presented them as tools applicable to the Maine Local T&D system. These smart grid tools will increase the amount of electricity sales that can be achieved using the same existing infrastructure, avoiding (or at least postponing) more expensive infrastructure investments that would otherwise be required. However, whether the existing private-party interests in Maine are aligned with the optimum application of these smart grid tools is unclear. To the extent that synchrophasors and power donuts lead to increases in power quality (voltage and frequency control), the resulting reduction in congestion costs would be aligned with the interests of independent power producers. Power generators could be motivated to work with the T&D utility to implement these technologies. This pressure, along with the potential for increased sales volumes would motivate the T&D utility to an extent. However, faced with an alternative, more expensive capital investment that would reduce congestion similarly, the T&D utility will be motivated by its economic returns, which are linked to its capital investments. Again, that effect holds as long as the utility expects Commission approval of the expenditures (discussed on p. 27).

Table 7: Technologies, Functions and Achievable Benefits for Maine Local T&D System from Future Smart Grid Technologies and Systems

Technologies, Functions	Achievable Benefits		
	ISO-NE	**MLCC**	**T&D Utility**
Integrated EMS/ SCADA/DMS/OMS solution. Includes SCADA controls monitored by YUKON system, for CMP.	Required to meet reliability criteria. Provides data to MLCC EMS. (CMP, pp. 22-23). CMP expects its integrated systems to be operational by 2014. (CMP, p. 22). Data can be used for: distribution load analysis (BHE, p. 13); integrated voltage and VAR control, emergency voltage conservation, real-time metering, monitoring, control, and outage management, dispatch of distributed generation and distribution load management, increase system reliability, and reduce transmission losses (CMP, p. 23); line monitoring, and the Smart Grid Operations Control Center (GridSolar, p. 18).		
Intelligent distribution system devices in distribution substations and on distribution feeders.			Integrated into the AMI WAN, these micro-processor controlled devices – reclosers, capacitor banks, and voltage regulators – become part of the centrally controlled and operated EMS to increase system reliability (CMP, p. 24).
Revenue protection software.			Improves theft-of-service detection, reduces theft (BHE, p. 12).
Demand-response capability.			Load management (BHE, p. 13). Demand response combined with changes in rates will offer cost saving opportunities for participating customers.
BHE cites load management as a benefit to the Maine Local T&D System, but CMP lists load management in the customer end use category. (CMP, p. 28).			

- **What, if anything, is Maine *not* doing about implementation that might be helpful either now or in the future?**

The same issues relate to providing NTA resources on Maine's local T&D system, as on the bulk transmission system. The important question is whether existing T&D company incentives and the planning and decision-making procedures that apply to the Maine Local T&D System are sufficient to produce the most economically efficient outcome, selecting NTA and non-distribution alternative (NDA) resources when they are cost-effective. What differs is jurisdictional oversight and authority. Given the local control, it may be easier at this level to establish an SGC or NTAC or revise rules and regulations to better solicit direct bids of NTA solutions from NTA owners. Maine's Certificate of Public Convenience and Necessity (CPCN) process is the likely framework to be modified to support cost-effective NTA solutions. Recent statutory changes in Maine require that NTA solutions be considered when determining the public need for a proposed transmission line (Title 35-A §3132(6)).[24] However, the incumbent

[24] Maine Public Law, Chapter 31. (2011). http://www.mainelegislature.org/legis/statutes/35-A/title35-Asec3132.html. Section 3132(6) states, in part:

> **Commission order; certificate of public convenience and necessity.** In its order, the commission shall make specific findings with regard to the public need for the proposed transmission line. … In determining public need, the commission shall, at a minimum, take into account economics, reliability, …state renewable energy generation goals, …and ***alternatives to construction of the transmission line, including energy conservation, distributed generation or load management*** [emphasis added].

transmission and distribution utility is only required to file a CPCN with Maine's PUC for voltages of 69 kV and above. This requirement effectively neglects Maine's jurisdiction on permitting sub-transmission construction, as Maine transmission is mostly at 34.5 kV and 115 kV (the latter predominantly under FERC/NERC/ISO-NE jurisdiction). As such, it is at least questionable whether Maine statutes authorize the PUC to consider NTA or NDA solutions for the Local T&D level.

- **Barriers:**
  - **What barriers, if any, might prevent Maine from fully achieving smart grid benefits?**

As discussed in the analysis of consumer end uses, the Commission should thoroughly explore two BHE and CMP assumptions: (1) the full and conceivably exclusive extent of T&D company involvement in consumer end-use smart grid applications; and (2) the idea that the T&D company is the only or the best agent to serve consumers with smart grid functions that control end-use devices. Critical considerations regarding smart grid coordination involve the interplay between the T&D companies and competitive retail service providers and consumers. CMP offers assurances that it is preparing to integrate in some ways with competitive service providers (CMP, p. 1). BHE also recognizes the need for such integration (June 7, 2011 *Transcript of Technical Conference* in Docket No. 2010-267, pp. 53-54). But both companies report plans to extend their smart grid facilities through the smart meter and into the consumer's facilities (BHE, pp. 7, 8, 10; CMP, pp. 2-3, 28-30), and both companies imply that only the T&D company is positioned to function as the intermediary between smart grid commands and controls of consumer end use equipment and the ISO (BHE, pp. 15, 17-18; CMP, pp. 12, 26-27). There is no reason to believe the T&D companies are either the only or the best entities suited to these activities (see pp. 43-44).

In addition, given the current structure of Maine's electricity market, there appears to be at least one specific instance of the principal-agent problem that could prevent the full implementation of smart grid technologies. It is the situation between the T&D utility and the power producer with regard to conservation voltage reduction.[25] Some reduction in congestion from better VAR control will likely be implemented by the T&D utility because, as a least-cost solution in certain applications, it will be the prudent investment allowed by Commission regulation. However, a power producer's lack of control of the transmission infrastructure might lead to less-than-optimal VAR control and conservation voltage reduction. Effective conservation voltage reduction can reduce electricity sales, which does not align with T&D utilities' operating under traditional, non-decoupled, electricity-sales-based revenue recovery.

Regionally, ISO-NE does have ancillary service markets – one for locational reserves and one for voltage regulation. These help by monetizing locational value to some extent, but they are presently small markets served by existing resources and are not attracting new entrants.

Irrespective of decisions on these important concerns and whether or not a smart grid coordinator is designated in implementing smart grid capabilities for the Maine Local T&D system, the Commission should review and evaluate the incentives that guide T&D-company planning and decision-analysis procedures. The Commission should establish appropriate metrics and performance standards and adjust incentives if needed to ensure that Maine's T&D companies implement smart grid so that the costs of owning and operating the Maine local T&D system are reduced as much as practical while meeting or

[25] The principal-agent problem is illustrated by the classic landlord-tenant problem: Entities are somewhat motivated to increase energy-use efficiency (e.g., changing thermostat settings to reduce the tenant-paid heating and air conditioning bill) but not fully motivated (e.g., a tenant who does not own the rented building is not likely to install additional insulation or make other long-lasting and often long-payback building improvements). Details of the Pay As You Save (PAYS®) financing system were designed in part to solve the landlord-tenant problem. See http://www.paysamerica.org/, retrieved 27 Dec 2011.

exceeding standards for reliability, physical and cyber security, and high-quality customer service.

- **What is the potential role of a Smart Grid Coordinator in overcoming those barriers?**

An SGC could not, by itself, overcome existing jurisdictional questions or barriers. If the Commission were to establish suitable metrics and performance standards, and if changes to the transmission planning rules and cost-allocation practices put NTA solutions on an equal footing, then an SGC could be instrumental in identifying and vetting NTA options. The same is generally true with respect to NDA options: If the Commission were to establish suitable metrics and performance standards and if distribution system planning and procurement practices put NDA solutions on an equal footing, then an SGC could be instrumental in identifying and vetting NDA options.

Potential roles for an SGC include: (1) educating all parties about NTA and NDA technologies, including technical and economic potential (see pp. 40, 46); (2) supporting NTA and NDA solutions, in ISO-NE planning and in CPCN hearings before the Maine PUC; and (3) soliciting bids and entering into contracts for implementing NTA and NDA solutions (see p. 30).

C. Generation

Smart grid capabilities will facilitate interconnections, especially for distributed generation. Smart grid has important roles to play in providing better market access for distributed generation (DG), including dispatchable DG and backup generators (BUGs), and electricity storage technologies, all of which can provide demand-response capabilities.

- **Existing Tools: What smart grid tools are available today?**

BHE mentions only the Remote Interface Gateway (RIG) technology used to dispatch the Company's diesel generators. BHE also monitors and controls its diesel generators using SCADA. (BHE, p. 15).

CMP broadly characterizes its AMI and related two-way communications infrastructure as "facilitate[ing] the integration and dispatch of generation resources in Maine." CMP also indicates its intention to provide "access to the Bulk Electric System, generator capability testing, and Smart Grid information systems." (CMP, p. 25). CMP explains:

> The goal of generator and storage interconnection at all levels is to enable flexible supply and grid use, subject to technical limits, as well as dispatchable services that can be used as instructed energy, operating reserves, capacity, volt-VAR service, and distribution load management (CMP, p. 26).

GridSolar cites the ISO-NE dispatch system as an existing tool but notes that it functions "only on the BES" (GridSolar, p. 22). GridSolar points out:

> [T]he current system can dispatch generation to meet reliability needs, but it can only interact with those large generating units interconnected to high voltage transmission lines. We are not aware of any system or capability at ISO-NE or the utilities that enables dispatch of smaller or distributed generation resources in response to threats to local or sub-regional grid reliability. (GridSolar, p. 22).

Existing smart grid tools that support generation are summarized in Table 8.

Table 8: Technologies, Functions and Achievable Benefits for Generation Resources from Smart Grid Assets and Activities Already In Place or In Deployment

Technologies, Functions	**Achievable Benefits**	
	ISO-NE, MLCC, and T&D Utility	**CEP, TSP, and Customer**
DG interconnection (CMP, p. 27).	Interconnection procedures protect the utility and its equipment.	Interconnection procedures assure customer rights.
Market access for DG and demand-response services, including electricity storage (CMP, p. 27).		It would be cost-prohibitive for small generators to be ISO market participants. T&D companies or other third parties can aggregate and represent DG in the ISO-NE market.
Coordination for reliability.	Improve reliability by coordinating grid resources during contingencies, power outages, planned maintenance, and day-to-day switching (CMP, p.27). Improve transformer load-management, and capacitor bank operation (GridSolar, p. 20).	Properly managed DG can help customers avoid power quality problems and outages.
Remote Interface Gateway (RIG).	Electronic signals from ISO-NE to BHE, notify when to start or stop generators (BHE, p. 15).	

- **Future Tools: What smart grid tools are expected in the future?**

Neither BHE nor CMP identify future smart grid tools expected to provide specific benefits to generation. BHE does not address this subject at all. CMP describes in generic terms how its smart grid efforts will result in "greater operational efficiencies and… a broader array of customer services and options" (CMP, pp. 8, 26). Among the customer-service options CMP lists are:

- Distributed generation monitoring and control;
- Electric vehicle charging stations and network load management; [and]
- Energy storage to alleviate network constraints and facilitate renewable energy.

GridSolar explains:

> One of the primary paradigm shifts enabled by the smart grid is the ability to use distributed instead of centralized generation resources to meet grid reliability demands (GridSolar, p. 23).

Like CMP, GridSolar discusses future benefits in rather general terms. GridSolar reports:

> [T]he ability to use accurate real-time information, communications, and controls will enable far more cost-effective dispatch of these new [DG and other NTA solutions] technologies, producing substantial operational savings as well" (GridSolar, pp. 23-24).

GridSolar lists these technologies in the context of future smart grid tools: solar DG; biomass/CHP; BUGs; battery storage (GridSolar, pp. 24-27). Those are not smart grid tools, per se, and all but battery storage can be considered to be in existence already. However, changes in rates and ancillary services payments are needed to illuminate the values these technologies provide and boost market acceptance.

Future smart grid technologies and functions to support generation resources are summarized in Table 9.

Table 9: Technologies, Functions and Achievable Benefits for Generation Resources from Future Smart Grid Technologies and Systems

Technologies, Functions	Achievable Benefits	
	ISO-NE, MLCC, and T&D Utility	**CEP, TSP, and Customer**
Induce generation to locate where it provides grid efficiency and reliability benefits (GridSolar, p. 21).	Helps provide least-cost solutions for meeting T&D needs.	Helps DG providers marketing services to customers, by monetizing locational value. Enables customer cost savings.
Dispatch DG including **Back-up Generators (BUGs)** to meet reliability needs (GridSolar, pp. 22, 24-26).	Provides an additional, potentially lower cost, tool for meeting reliability needs.	Helps customers avoid power quality and reliability problems. Helps DG and BUG owners and operators to maximize value.
Battery Storage (GridSolar, pp. 26-27).	Helps provide least-cost solutions for meeting T&D needs. Helps variable output generation to match loads.	Helps customers avoid power quality and reliability problems.

- **Implementation in Maine:**
  - **How is Maine doing on implementing the existing smart grid tools and paving the way for implementing future tools?**

Maine has a longstanding tradition of promoting DG. Maine's interconnection procedures are considered "the strongest in the country." Maine's current net metering program is flexible. It allows generators up to 660 kW, including high-efficiency combined heat and power (CHP); shared ownership of net-metered systems; up to 10 meters aggregated against a single renewable facility; and no program limit on net metering, by utility or for the state as a whole. (Network for New Energy Choices, 2011, p. 43). However, there has been little focus to date on implementing smart grid tools for distributed generation.
One area of action is ongoing efforts to install AMI meters and implement dynamic pricing. These efforts should, in theory, allow for net metering based on dynamic market pricing. Dynamic net metering will provide accurate price signals to small-scale distributed generation, providing higher compensation to dispatchable generation technologies (e.g., biomass and some hydro) and those that produce energy when it is most needed (e.g., solar). Dynamic net metering can also work in concert with demand response and load management to reward customers who reduce on-peak power demands.

  - **What, if anything, is Maine *not* doing about implementation that might be helpful either now or in the future?**

GridSolar believes there is an important gap in electric generation planning: No entity presently has sufficient motivation to focus on the locational aspects of generation and the potential for distributed generation, by virtue of its specific location on the grid, to deliver important system benefits (GridSolar, pp. 21-22). Thus, GridSolar concludes that a vitally important role for an SGC is to develop and champion all varieties of distributed resources, including DG and storage technologies, as potential contributors to NTA solutions.

- **T&D costs and rates are not differentiated by location**

In the history of public utility regulation, an important premise was that there should be no undue discrimination among similarly situated customers (Bonbright, Danielsen, & Kamerschen, 1988, ch. 20). Rates were the same for similar customers, no matter where the customers were located in the entire service territory of each regulated utility. Because of the longstanding practice of establishing rates for the whole service territory of each T&D company, tension exists between the idea of avoiding discrimination and the ability, perhaps the need, to differentiate markets geographically – at least by T&D cost of service. Where it can be demonstrated that the cost to serve customers depends on and differs substantially because of geographic location, and such locational cost-of-service differences are long-lived, then rates differentiated by location might be justified. That would be an example of due discrimination, based on objective, longstanding cost differences.

As already mentioned, ISO planning requirements and cost-allocation practices could be altered to better reflect locational differences in the cost of service (see p. 27). Presently, however, ISO-NE transmission rates treat the entire state of Maine as one load zone and do not further differentiate transmission service costs by smaller geographic area. Necessary to the planning and identification of NTA resources will be ongoing review of ISO-NE practices and the removal of any otherwise nonessential barriers that are preventing the widespread introduction of least cost distributed resources. The Commission should work with interested parties to make the Maine Local T&D system planning process as transparent as practical and take all reasonable steps so that the planning process differentiates among and takes into account the locational costs of service.

Even without directly incorporating differential locational costs into consumer rates, some opportunities exist to encourage distributed resource prospectors to identify and develop resources that will produce the greatest system benefits and minimize system costs. One plausible approach might be to use feebates to encourage installing and operating resources in specific areas. In a feebate system (Boonin, 2008), fees would be charged to resources interconnecting and operating in areas where few or no system benefits accrue, and revenues from those fees would be used to reward resources for interconnecting and operating where system benefits are achieved.[26] The Commission should consider applying “feebate” policies for the Maine Local T&D system. This mechanism to differentiate distribution system costs by location can be explored and possibly implemented, whether or not an SGC is established.

This issue is of the utmost importance when considering the potential role for non-transmission alternatives and the question whether any entity – utility, competitive provider, demand-response aggregator, Efficiency Maine, or an SGC – can or will target specific customers as potential markets for specific services because of their geographic location. NTA solutions, by their very nature, are inherently location specific. In order to avoid or even to postpone temporarily a need for constructing any specific transmission asset, ample NTA resources must be available in a particular area. An NTA could be comprised of any suitable amalgamation of distributed resources, but the resources have to be available, sufficient, and concentrated in the right locations in order to function as an NTA.

Smart grid–enabled generation resources and consumer end-use applications, though, can be marketed in any geographic location. Early marketing attempts are most likely to focus on non-geographic attributes of potential generators or consumers. There are some reasons why DG marketers will focus on specific geographic territories. For example, marketers seek early adopters, who might be geographically clustered

[26] For other distributed resources policy prescriptions, see Lovins & Rocky Mountain Institute, 2002.

in particular areas identified by demographic data (e.g., income and education criteria). And marketers of renewable energy systems – wind explicitly, but also to some extent bioenergy, hydroelectric or hydrokinetic, and solar – have to focus attention on those geographic areas at or near the best available renewable resources. Still, there is no reason to assume that those areas will coincide with the locations most in need of or most likely to benefit from NTA applications.

Furthermore, if marketers do attract consumers in the particular areas requiring NTA solutions, then those resources (e.g., demand-response, load control, and distributed generation) will be managed in ways that might or might not meet the needs or requirements of an NTA coordinator. Researchers are already developing predictive models to demonstrate how populations of distributed energy resources controlled by independent decision makers can be assembled rapidly and dynamically into "virtual power plants" capable of meeting specific resource needs (Duan & Deconinck, 2011; Mihailescu, Vasirani, & Ossowski, 2011; Zimmerman, Smith, & Unahalekhaka, 2011). Contractual means would need to be developed, though, to ensure that an NTAC could successfully oversee NTA functions that depend on resources belonging to multiple customers and receiving services from multiple marketers, possibly including T&D companies, CESs, CSPs, TSPs, and so on.

- **Market-participant interests are not fully aligned with energy-storage capabilities**

As OPA construes, the retail electricity market does not yet include entities whose interests clearly align with energy-storage capabilities (OPA, p. 18). On the other hand, as storage-technology costs continue to decrease, it is easy to imagine tipping points where competitive suppliers will offer storage services to customers that value high reliability. For the present, power producers are motivated to enter the energy-storage market to the extent they can make money from the on-peak and off-peak electricity price differential. The benefit of frequency regulation provided by energy storage has been monetized in the ISO-NE ancillary service market (the regulation market), but this market is presently very small and has much overcapacity, leaving little economic incentive for new participants such as storage to enter the market. In addition, with such benefits split between existing parties, it may be that one party does not see enough benefit to implement the technology when otherwise on a total system basis the energy storage technology would provide ample benefit to be economically viable.

Again, irrespective of any decision about an SGC, the Commission should direct interested parties to review and report on how Maine's regulatory system affects cost-effective energy storage and EV charging. The parties should identify and recommend regulatory changes, if necessary, to remove institutional and regulatory barriers that would otherwise prevent adoption.

Electric vehicles (EVs) can also be classified as both generation or consumer end-use technology, because of their similarity to electricity storage technology and ability to deliver at least short-term generation services to the grid. The promotion and implementation of EV charging is fairly well-aligned with the T&D utility's motivations. EVs represent incremental load that will sometimes require increased capital investments upon which the utility can earn return. T&D companies would generally want to minimize the O&M costs associated with vehicle charging stations. However, EV charging service might be provided by competitive providers.

- **Barriers:**
  - **What barriers, if any, might prevent Maine from fully achieving smart grid benefits?**

As both BHE and CMP conclude, the T&D companies must have at least some oversight of the operational functions associated with dispatch and control of distributed generation (BHE, pp. 10, 15, 17-18; CMP, pp. 2, 12, 25-27). Nevertheless, smart grid capabilities eventually will enable DG control by third parties. This includes the functional equivalent of automated generator control and the near-real-time management of aggregated groups of DG units. Standards for communications protocols to meet these functional requirements are being developed by the National Institute of Standards and Technologies (http://www.nist.gov/smartgrid/priority-actions.cfm). These functions do not imply a need for SGC operational control, though. It could prove cumbersome to superimpose SGC control in addition to the standard smart grid provisions for managing distributed energy resources. Cossent, Gómez, and Olmos (2011) describe some of the inherent difficulties and remaining challenges in implementing smart grid tools – along with changes in rates, terms, and conditions of service and other policies – to support adoption of cost-effective distributed generation.

To maximize the use of DG, Maine's net metering program would require a change in provisions for net excess generation (NEG). At present, any net excess generation at the end of each year is automatically credited to the utility. That could limit opportunities for net-metered DG to respond to market signals. An alternative to net metering could be authorizing DG to operate as merchant plants, providing behind-the-meter retail service to a host facility (or facilities) and also producing and selling wholesale electricity. DG aggregators that serve the role of wholesale market participants would likely be needed to represent and manage small DG systems. The role or market participant could be filled by T&D companies or third parties, on a regulated fee for service basis or by bilateral contract. Maximizing the value of DG in wholesale markets would also require coordination and aggregation of customer demand response, load management, and energy efficiency.

- **What is the potential role of a Smart Grid Coordinator in overcoming those barriers?**

Both educational and planning roles for DG, BUGs, and the other correlated customer end-use options exist in the near term. As outlined by Lovins and the Rocky Mountain Institute (2002), DG can produce many potential locational values that have not been included in traditional utility accounting and least-cost integrated resource planning. Smart grid tools and dynamic market prices should go a long way towards clarifying locational values and making them visible to market participants, but having an SGC entity dedicated exclusively to NTAs and NDAs would ensure a concerted effort.

Recent research (Krishnamurti, et al., 2011, in press) underscores the need for education to correct consumers' "erroneous beliefs…, misconceptions…, [and] unrealistic expectations… [and] suggest[s] substantial, unmet challenges for ensuring informed consumer decisions." (See also Lineweber, 2011, in press). As discussed in Section IV.D (pp. 43, 46): (a) T&D companies might not be ideally situated to fulfill this role; (b) EMT could play an important, ongoing role; and (c) there could be advantages to having an SGC fulfill this role. The near-term need for education does not necessarily translate into a permanent need for an SGC, though.
The Commission should be prepared to assign SGC responsibilities for DG prospecting and encouraging DG development to one or more entities for the near term, as a pilot project, and then carefully monitor and evaluate the progress in achieving general smart grid and specific NTA objectives. That function of achieving some particular NTA objectives is presently being considered in Docket No. 2011-138.[27] It makes sense to learn from a pilot project before establishing any new, long-lived SGC entity or entities. If pilot projects are successful, the Commission should consider temporary or short-term SGC assignments for the purposes of consumer education, NTA identification, NTA procurement, and NTA coordination. Those efforts should also be carefully monitored and evaluated. Then and only then will it be clear whether a more permanent SGC should be established.

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[27] Docket No. 2011-138, opened 11 Apr 2011, *Central Maine Power Request for Approval of Non-Transmission Alternative (NTA) Pilot Projects for the Mid-Coast and Portland Areas*.

D. Consumer end uses

Smart grid components that are specific to consumer end uses include web portals, home area networks (HANs), in-home devices (IHDs), smart thermostats, active load management, demand response, and rates designed to support the smart operation of all of those. Consumer education and ongoing communication with consumers should also be included in the category of consumer end uses.

- **Existing tools: What smart grid tools are available today?**

Maine T&D companies are in the process of completing installations of AMI systems, which include automated meters and the associated two-way communications infrastructure between the meters and the utility. Maine T&D companies are also beginning pilot projects to test some smart grid tools for consumer end uses. (BHE, pp. 6-9, 16-18; CMP, pp. 28-30).

Existing smart grid tools for the benefit of consumer end-use are summarized in Table 10.

- **Future tools: What smart grid tools are expected in the future?**

BHE plans to conduct a trial of HAN and dynamic pricing in the near future. BHE says its trial will include smart thermostats that can respond to pricing signals from its smart meters. (BHE, p. 16). BHE also plans for load controls, but only for a few select uses, such as "electric water heaters and "other loads such as a central air handling unit, air conditioner, or a pool pump" (BHE, p. 13).

Similarly, CMP "contemplate[s]… fully market[ing]… across the CMP service territory… demand-response energy rates, load control devices, and net metering for distributed generation at customer premises" (CMP, p. 28). CMP also expects "the introduction of new programs," which could include various demand-response and peak-time rates, communicating programmable thermostats, in-home displays, web portals, and voltage-monitoring systems (CMP, pp. 29-30).

Future smart grid tools for the benefit of consumer end use are summarized in Table 11.

- **Implementation in Maine:**
  - **How is Maine doing on implementing the existing smart grid tools and paving the way for implementing future tools?**

The Maine PUC is presently working with both CMP (in Docket No. 2010-132) and BHE (Docket No. 2010-14) to incorporate dynamic-pricing options into their billing systems, for at least the electricity supply portion of electricity rates (that is, for standard offer generation rates). The Maine PUC has also solicited information from competitive electricity providers (CEPs) to understand how the present standard offer process can be modified to incorporate dynamic rates. Presently TOU rates exist only for the distribution portion of rates for small commercial and residential customers.

Both BHE and CMP report plans to implement narrowly prescribed load-management offerings to consumers for electric water heaters and specific other loads (BHE, pp. 11-12; CMP p. 28). Smart appliances and smart thermostats, controlled by smart energy management systems, will be capable of much broader and more nuanced load management and demand response, though. The Commission should be mindful, as OPA points out, that utilities might not be in the best position to market such services to consumers (OPA, p. 29).

Table 10: Technologies, Functions and Achievable Benefits for Consumer End Use from Smart Grid Assets and Activities Already In Place or In Deployment

Technologies, Functions	Achievable Benefits				
	T&D Utility	**CEP**	**CSP**	**TSP**	**Consumer**
AMI – Interval Meter Reads (BHE, pp. 15-16; GridSolar, p. 35).	More granular, near-real-time interval meter data provides details for scheduling, planning, budgeting, and managing energy use.				
AMI – Remote Connect/Disconnect (BHE, pp. 8, 10).	Reduces labor costs.				Speeds service start & stop orders
Load-control devices (CMP, p. 28; and including ETS technologies described in TESM *Comments*).	Allows direct control of non-essential demands in response to economic or reliability needs. Works in conjunction with dynamic pricing and demand response.				
Net metering for DG (CMP, p. 28).		Not applicable.			Applicable only for customers on standard offer service.

- **What, if anything, is Maine *not* doing about implementation that might be helpful either now or in the future?**

The Commission should keep in mind the potential value of competition in supplying smart grid consumer-service functions. For example, CEPs, competitive energy services providers (CSPs), EMT, and consumers will all have a direct interest in using AMI capabilities to best manage consumer end uses. At present, however, T&D companies and CEPs are generally motivated to maximize energy throughput and sales, while at least some of the retail service providers and consumers are generally motivated to reduce utility purchases and costs. These differences in incentives and motivations raise important questions about AMI infrastructure. To what extent should AMI be developed as a common carrier, ready to support program and service offerings from T&D companies, CEPs, CSPs, EMTs, and TSPs? What functions should remain open for use by competitive suppliers? How will the Commission ensure fair cost allocation between the T&D company and the competitive suppliers? The Commission should not authorize cost recovery for any smart grid facilities that provide customer end-use services unless those facilities use open-systems protocols and can be made available at cost to competitive service providers.

In particular, there is no present evidence to suggest that T&D companies are best suited to produce and deliver web presentment software, HANs, IHDs, smart thermostats, and active load management. Most CEP company business models are presently more closely aligned with maximizing sales and throughput, too, rather than most efficiently meeting consumer needs. As Kushler & Witte (2001, pp. iii-iv) conclude:

> [F]or a variety of reasons, the retail electricity commodity supplier industry has not demonstrated itself to be an effective vehicle for achieving energy efficiency improvements. ... [T]he vision of a robust supplier industry bundling the electricity commodity and energy efficiency to provide customers with lowest-cost energy solutions has simply not materialized.

Table 11: Technologies, Functions and Achievable Benefits for Consumer End Use from Future Smart Grid Technologies and Systems

Technologies, Functions	Achievable Benefits				
	T&D Utility	**CEP**	**CSP**	**TSP**	**Consumer**
Demand-response & dynamic or real-time pricing, time-of-use tariffs (CMP, p. 28; BHE, p. 16; GridSolar, pp. 35-44).	Integrates with rates. Can include aggregated demand response.				Time-of-Use savings.
Web-based Customer Information Portal.				Helps consumers understand and plan use and cost.	
Home-Area Networks (HANs) and **Smart Thermostats** (BHE, p. 16).	Reduces peak demand and cost.			Helps consumers understand, plan, and control use and cost.	
Dynamic pricing (BHE, p. 16) and **demand-response energy rates** (CMP, p. 28).	Reduces peak demand and associated utility and consumer costs. Enables profitable curtailment services. Helps reveal time-of-use values.				
Programmable, communicating “smart” thermostats (CMP, p. 29; BHE, p. 16).	Integrates with rates. Allows set-it-and-forget-it convenience. Peak-usage reductions. Conservation & Time-of-Use cost savings. Allows for control “by commands from the AMI operations center, according to instructions set up by the customer” (CMP, p. 29). Reduces peak loads and generation costs (BHE, p. 16).				
In-home displays, real-time display portals, home area networks (HANs) (CMP, pp. 29-30; BHE, p. 16).	Integrates with rates. Smart grid enabled appliances respond to price signals.				Conservation & Time-of-Use savings
EV charging stations & load management (vehicle to grid, or V2G) (BHE, p. 17).	Integrates with rates. Varies charging loads and V2G grid services according to economic and reliability criteria. Reduces costs for both system and consumer.				
Electricity storage.	Integrates with rates to enable profitable operations for storage owners. Varies charging loads and discharging (generation) services according to economic and reliability criteria. Reduces costs for system. Reliability benefits and cost savings for on-site end users.				
Voltage monitoring and control and conservation voltage reduction (CMP, p. 30).	Improves planning & preventive maintenance.			Protects equipment. Helps prevent outages.	

BHE and CMP are both reportedly in the process of building out smart grid infrastructure as if the T&D companies will be the entities to engage consumers in dynamic pricing, demand response, and load management (BHE, pp. 16-17; CMP 22-23, 29-30). Neither the utilities nor the Commission should assume that the T&D company is best suited to these roles in the long term, though. Experiments and pilot programs are worthwhile, but these activities should not automatically be ceded to the utility without engaging in a conscious process of clarifying the T&D company motivations and establishing performance criteria and a regulatory structure under which those functions will operate. If the T&D companies are going to be engaged in these aspects of consumer service, then metrics and performance standards should be developed to monitor and evaluate progress and ensure that cost recovery is ultimately related to successful implementation. The Commission, not T&D companies, should determine what parts of the smart grid relationship with consumers are best left to competitive suppliers, and whether and how standard offer service will need to be changed to reflect new smart grid capabilities.

Early research suggests that some consumers will be motivated to install and utilize end-user equipment such as in-home displays or smart grid–enabled appliances, given the proper pricing signals and having the necessary knowledge to make an informed, rational decision (Faruqui & Sergici, 2010). However, many studies have found that consumers often expect high rates of return (e.g., 30-40% per year) and rapid pay-back periods (e.g., often one year or less) when determining whether to invest in energy-saving technologies (DeCanio, 1993; Golove & Eto, 1996; Greene, 2011; Hofmeister, 2010; Sorrell, 2004; Tonn & Martin, 2000). And decades of experience with energy-efficiency programs indicate that rebates or other financial incentives are frequently needed to attract consumer attention to investment opportunities that are otherwise fully cost-effective (Geller, et al., 2006; McLean-Connor, 2009; Transue & Felder, 2010). The ready availability of low-cost, hassle-free financing integrated with quality assurance can also be a key ingredient, necessary to open up consumer markets for energy efficiency (see note 25, p. 34).

Furthermore, studies show that consumer groups have a variety of attitudes and predispositions towards energy efficiency (see, for example, Sütterlin, Brunner, & Siegrist, 2011). Thus, smart grid education plans need to reflect the best available information about consumer market segments.

Plus, it remains to be seen what percentage of customers will take an active role in energy management decisions and maintain the necessary efforts in the long term, or if set-it-and-forget-it convenience will be readily achieved and successfully marketed. Studies of automatic set-back thermostats, for example, have found that the consumers most likely to install those devices were also the most likely to be already engaged in manual thermostat operations. Thus, long-term energy savings from automatic controls could be smaller than predicted. (See, for example: Lutzenhiser, Moezzi, Hungerford, & Friedmann, 2010, pp. 7-170–7-171; Ryan & Young, 2008, p. 27.) Also, automated demand-response capabilities can be pre-programmed into smart-grid-enabled energy-management systems (EPRI, Mar 2011, pp. 7-13–7-14), but it remains to be seen whether and to what extent such systems can or will be programmed to operate in two separate modes: (1) to help consumers save money while maintaining adequate end-use services; plus (2) to function under certain circumstances as an NTA resource. The question to be addressed is the difference between the two modes: Will consumer preferences for cost savings in the first mode leave untapped sufficient incremental resources that could be called upon when needed to ensure successful operation of an NTA? Or will the first mode already capture the same energy and capacity savings needed by the second mode? If the two modes will achieve the same or similar ends, then the added value a smart grid coordinator could bring needs to be questioned.

Also, EPRI's recent analysis (Mar 2011, Section 7) suggests that many smart grid capabilities will be deployed gradually and are not likely to reach large percentages of consumers anytime in the near future. For example, EPRI forecasts that by 2030:

- only 10% of residential consumers will have home energy management systems;
- 20% of residential customers will have in-home displays;
- smart grid–enabled appliance use is likely to "level off" as market share approaches 40%; and,
- only 5% of commercial buildings will have energy management systems equipped with automated demand-response capabilities.

Thus, depending on the breadth and depth of changes in demand that need to occur in any specific locations, the challenges could be daunting both for implementing and successfully operating an NTA.

The Commission should continue its efforts to begin implementing dynamic pricing, including changes to standard-offer service. The Commission should ensure that early dynamic-pricing efforts are carefully monitored and evaluated. Evaluation data should be used to inform the Commission and all interested parties prior to establishing more widespread dynamic-pricing programs.

- **Barriers:**
  - **What barriers, if any, might prevent Maine from fully achieving smart grid benefits?**

AMI enables these functions through the provision of smart meters and communications systems. That does not mean, however, that the entire AMI infrastructure should be developed and implemented by T&D companies, nor that T&D companies should be the only entities offering smart grid services to consumers. The AMI infrastructure will serve the T&D company's needs for communications and controls to best manage its T&D functions, but other actors will be motivated to use the AMI infrastructure for customer service purposes and the T&D company has much weaker or even negative motivations for maximizing consumer benefits that result in reduced sales.

AMI provides functions that the incumbent utility does not apparently have motivation to implement. End-use direct load control, which is not presently a functional capability of Maine's AMI meters, is not well-aligned with the electricity sales profit motive, although the additional capital cost, and the return available on that capital cost, provides a countervailing motive. But again, to the extent that direct load control mitigates the need for more expensive capital investment in traditional transmission and distribution infrastructure, it is less likely that direct load control applications will be appropriately adopted. Dynamic pricing may also not be fully aligned with the interests of the T&D utility, and with regard to generators, dynamic pricing is mixed, as baseload generators are likely to see an increase in demand while peaking facilities will see a decrease. However, dynamic pricing is clearly in the interest of providing a more efficient electricity market.

The motivation to utilize AMI meters and associated communications systems to implement dynamic pricing is complex. Dynamic pricing might or might not increase the volume of electricity sales. Consumers might decrease usage during times of higher-priced on-peak rates but then increase usage as much or more during times of cheaper off-peak electricity rates (see Faruqui & Sergici, 2009, p. 21). Dynamic pricing is expected to reduce electricity sales during times of peak system loads, however, which would decrease the need for more capital investment in transmission and distribution infrastructure and thus decrease the potential for growth in T&D company returns.

Early experience indicates that relative to flat-rate pricing, TOU pricing may reduce peak loads by 4-5% and real-time pricing may reduce peak loads by approximately 15% (Faruqui & Sergici, 2009; Newsham & Bowker, 2010). While peak time rebates have not yet demonstrated an ability to reduce peak loads more than simple real-time pricing, and critical peak pricing (CPP) has produced modest incremental reductions in peak load (about 17% vs. 15% for real-time pricing), further reductions in peak load may be attained by combining a pricing scheme with direct load control utilizing smart grid technology. TOU with direct load control may reduce peak load by 26%, and CPP with direct load control by 30-36% (Faruqui & Sergici, 2009; Newsham & Bowker, 2010). It is important to note that combining real-time pricing with direct load control has not yet been studied. Given the degree of demonstrated peak load reduction of real-time pricing relative to TOU and CPP, it is conceivable that real-time pricing with direct load control could provide roughly 30% reductions in peak load. But savings estimates could prove to be optimistic. Such significant quantities of load shifting will reduce the price of both generated electricity and transmission and thereby reduce the impetus for load shifting.

The provision of demand response is becoming better aligned with the public interest as ISO-NE continues to revise market rules. CSPs providing demand response already participate in the day-ahead and real-time energy markets, as well as the forward capacity market. FERC (15 Mar 2011, Order No. 745) recently ordered that demand response in electricity markets should receive compensation equal to electric generation (that is, full locational marginal prices at all hours). ISO-NE draft market rules submitted to FERC for approval outline how demand response will become fully integrated with generation by 2015.[28] What equal treatment in the real-time markets fails to consider, though, is the potential value of demand response in providing an NTA service, valuable for long-term transmission planning. Equal treatment in the energy market does not compensate fully for the long-term locational value of where the demand response occurs, potentially avoiding transmission upgrade costs.

In the same vein as the earlier discussion about rates differentiated by location are rates differentiated by quality and reliability of service. In the past, it might have been considered discriminatory to provide some customers with higher reliability and others with lower reliability. The more widespread introduction of interruptible rates has somewhat changed this perception already. In the future, smart grid can enable more rate offerings differentiated based on quality and reliability of service, and an important question relevant to this proceeding is whether the various parties will be motivated to design, offer, and successfully market a broad portfolio of services to customers, so that the total cost of service to the whole population of consumers is minimized.

With or without an SGC, achieving the potential benefits of smart grid deployment will require rates that encourage energy efficiency and demand response and work in concert with consumer preferences. Early research identifies the need for coordination in these areas and suggests that "most customers…would be receptive to an integrated, packaged approach to managing their energy usage" (Goldman, Reid, Levy, & Silverstein, 2010). EPRI (March 2011, p. 7-2) observes, "Many of the experts who are studying the smart grid are increasingly adopting the view that a truly Smart Grid should require as little consumer participation as possible." As reported by Zimmerman, Smith, and Unahelakhaka (2011), though, there is little indication that large numbers of consumers will want to spend time managing their energy consumption. Rather than engaging in energy management on a day-to-day basis, there appears to be a preference on the part of the mass market of consumers to be able to "set it and forget it." Zimmerman, Smith, and Unahelakhaka (2011) explain:

> [T]he great majority of consumers will be unwilling to devote more than brief and cursory attention to electricity consumption in the buildings they inhabit, so an [energy management system] must (re)solve the building power optimization problem in real time with minimal dependence on human interaction.

Any or all retail service providers could be responsible for consumer offerings. Actors might include standard-offer service providers under Commission direction, plus CEPs, CSPs, and TPSs. Furthermore, EMT could play an important role in both educating consumers about opportunities and helping encourage them to make the best service choices by providing carefully designed measures that effectively combine consumer education and action with quality control and quality assurance. While the Commission itself can oversee dynamic-pricing tariffs in the best interest of ratepayers and EMT can educate consumers about the energy cost savings enabled by smart grid, an area that appears to be unfulfilled is the efficient provision of NTA and NDA resources. Absent a concerted effort on the part of a motivated agent, how likely is it that sufficient numbers of consumers in the specific locations necessary will manage their energy use to produce ample savings to fulfill the needs of NTA and NDA solutions (see pp. 38-38)? Suffice it to say that at the present time nobody knows the answer to that question, but without the efforts of a motivated agent the likelihood of success could be substantially lower.

T&D companies could have only modest roles in these areas. EPRI (March 2011, p. 7-2) acknowledges, "[T]here is growing belief that the enabling technologies to engage with consumers and their end use appliances and devices will originate from entities outside the traditional electric utility as part of a service bundle." Plus, there is at least some evidence that utility companies face an uphill battle for winning consumer trust about smart grid investments (Lineweber, 2011, in press).

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[28] http://www.iso-ne.com/regulatory/ferc/filings/2011/aug/er11_4336_000_prd_filing.pdf

- **What is the potential role of a Smart Grid Coordinator in overcoming those barriers?**

Long-term reductions in peak demand can reduce or even eliminate some needs for peak-power generation and additional transmission capacity. This effect directly relates to the prospects for an NTAC. The important question is, what additional, optimally beneficial peak load reduction might an NTAC produce, beyond what will be induced by dynamic pricing, the forward capacity market, and demand-response bids? ISO-NE already invites direct load control through its demand-response market. An SGC in the form of the NTAC proposed in Maine could provide consumer education, market, and conceivably even offer additional direct load control services. The goal would be to reduce peak system demand, above and beyond what is achievable through real-time pricing, to achieve particular NTA objectives.

An NTAC advantage would be in modeling the changes necessary to achieve NTA solutions, planning how to reach those levels, and then targeting, educating, and marketing to consumers in the specific locations. Demand-response bids into the forward capacity market and locational marginal pricing will create some future expectations and locational control, but not to the degree that a dedicated coordinator would.

This does not imply that the NTAC should have the role of controlling or managing the NTA solutions, though. As BHE points out, it is not practical for multiple parties to engage in controlling and managing the same smart grid services (BHE, p. 18). However, that fact by itself does not mean that control and management should be ceded to any particular market participant. With so much uncertainty about smart grid's future, the Commission should strive to protect and enhance rather than restrict competition.

Education and financial incentives focused on overcoming market failures could come from an SGC, but the Efficiency Maine Trust has already been created to focus on electricity consumption savings. EMT already subsidizes and educates about Energy Star[29] appliances, and Energy Star is considering including a 5% savings credit for smart grid–enabled appliances.[30] This overlap of energy efficiency and smart grid indicates the blurring of the distinction between energy efficiency and smart grid that is beginning to occur as the time value of electricity becomes more readily apparent, enabled by real-time pricing signals.

[29] ENERGY STAR is a joint program of the U.S. Environmental Protection Agency and the U.S. Department of Energy helping to save money and protect the environment through energy efficient products and practices. (About ENERGY STAR [webpage], http://www.energystar.gov/index.cfm?c=about.ab_index, retrieved 14 Sep 2011).

[30] http://www.sustainablebusiness.com/index.cfm/go/news.display/id/21741

V. Summary Conclusions

GridSolar envisions a smart grid coordinator with these responsibilities:

1. Monitor standards "to ensure that all smart grid activities in the state comply with all existing standards and legal requirements, and that all new smart grid investments are compatible with expected future standards and requirements" (GridSolar, p. 16);

2. "[M]onitor electrical conditions on the grid and respond to potential problems" (GridSolar, p. 18);

3. [P]rocess "information collected about the grid… to develop and recommend to the Commission NTA solutions. … [D]evelop and present [NTAs] to the Commission for consideration alongside transmission solutions presented by the utilities" (GridSolar, pp. 18, 21-22);

4. "[P]rovide information about the grid to third-parties who can… develop distributed generation resources, demand-response, geo-targeted energy efficiency and other solutions to meet actual and anticipated grid reliability problems" (GridSolar, p. 18);

5. Manage and dispatch "smart grid resources (including distributed generation, storage, and demand response) for reliability purposes" (GridSolar, p. 46);

6. Implement "programs designed to facilitate development of new energy services markets capable of providing smart grid applications" (GridSolar, p. 46);

7. Manage "third party access to the smart grid and smart grid functions" (GridSolar, p. 46);

8. "[C]oordinate… efforts with Efficiency Maine… to design and implement programs that target energy efficiency to those locations identified as having a grid reliability need" (GridSolar, p. 50); and,

9. "[E]ducat[e] the public about the value of a smart electric grid and about how to utilize the capabilities of the smart electric grid to lower electricity costs" (GridSolar, p. 50).

These are worthy objectives, but all could be addressed with or without an SGC. Most or all can be addressed, at least in part, by sagacious Commission oversight and guidance, including establishing metrics and performance standards for T&D companies and monitoring performance to ensure that objectives are being met. Primary examples include 1, 2, and 5. Some objectives will also benefit from cooperative and collaborative relationships with multiple parties that provide consumer end-use services. Primary examples include 6, 7, 8, and 9. Some objectives will be addressed through new contractual arrangements, especially contracts between T&D companies and consumer services providers, between EMT and consumer services providers, and between consumer services providers and customers. Primary examples include 2, 5, 7, and 8.

The objectives most difficult to address without any SGC entity are 3 and 4. Although T&D utilities already have the responsibility for developing and recommending NTA solutions, existing motivations and incentives are not strong enough to ensure their most exhaustive efforts. Additionally, irrespective of motivations and incentives, NTA solutions presently represent a broad array of new, emerging, and relatively untested resources. Furthermore, successfully operating some NTA solutions will depend in part on consumer behavioral responses that are challenging to model and predict accurately and could prove difficult to evoke and then maintain over time.

T&D companies could be assisted in efforts to identify and achieve NTA solutions by any and all interested parties, including retail service providers, EMT, and customers. Nevertheless, the presence of an independent SGC entity clearly focused on maximizing smart grid opportunities and tenacious in the pursuit of successful NTA solutions could be instrumental—at least in the near term, while everyone learns more about the capabilities of and how best to implement smart grid tools.

In addition, the long planning and construction horizon for new transmission projects could leave a role for implementing NTA solutions, even while any future transmission solution is being modeled, designed, proposed, evaluated, approved, and built. As Fershee (2011, p. 21) observes, "Any [high-voltage transmission] project is likely to take ten years to complete, not including the time to agree that such a project is needed."

The Commission can either wait to see how the situation unfolds, relying on existing market participants while consciously seeking incremental improvements in regulations to improve the likelihood of smart grid success, or continue proceedings to establish an SGC. Regrettably, the record in Docket No. 2010-267 lacks both (1) input from all parties that will be affected by the Commission's decision and (2) sufficient and reliable benefit and cost data to conclude which approach is most perspicacious. Furthermore, the need for support from an SGC could either diminish or grow over time as smart grid implementation continues and additional smart grid innovations come to the fore.

As BHE indicates:

> [T]he fast-developing nature of smart grid technology and systems suggests that to the extent any problems are identified today, those problems may not be problems at all by the time the T&D utilities' smart grid investments are finalized. Conversely, a current examination of potential problems may not identify all problems that may arise in the near future. In other words: a determination made today that a smart grid coordinator is not needed at this time does not mean that one may not be useful in the future. (Docket, October 15, 2010 *Comments*, p. 2).

Therefore, BHE recommends the following:

> Bangor Hydro suggests that at the conclusion of this proceeding, the Commission initiate a more organic and ongoing process to oversee the smart grid technologies and systems deployed in the state. Such a process could include a working group consisting of representatives of the T&D utilities, Commission staff, and various other stakeholders, with a mandate to provide an annual or twice-yearly report to the Commission on any issues identified with the implementation of smart grid technologies and systems in the state, and propose solutions to any problems identified. Such an ongoing process would be more responsive to the actual known needs of the electrical system and the users of that system than the one-time snapshot that the current proceeding represents. (Docket, October 15, 2010 *Comments*, p. 3).

BHE repeats these themes in its December 16 *Comments* (BHE, p. 14):

> It is not yet clear what operational or institutional changes are necessary or useful to enhance the value of the Smart Grid for customers, and describing such changes at this time would be premature. … [T]he fast -developing nature of smart grid technology and systems makes such a determination at any point in time problematic at best. Bangor Hydro's suggestion… to create a working group to monitor the organic evolution of the Smart Grid and its associated needs was intended to address this constantly changing dynamic.

The OPA recommends “a more collaborative approach to developing and agreeing upon this information as it applies to the Maine/New England grid.” (Docket, October 14, 2010, *Comments*, pp. 1-2). OPA is also prescient in observing:

> [I]n order to realize the State's smart grid goals, the utility has to be an active and willing participant in programs and initiatives involving access to functions that involve its system and other parties… .” (OPA, p. 23).

The OPA Consultants surmise:

> Given the broad set of responsibilities entailed and the different types of expertise and activities required, the Commission should consider limited approaches to the role of Coordinator, at least initially. One approach would be to authorize the Coordinator to manage a limited sub-set of functions, with the T &D utility assigned to manage the remaining functions. (OPA, p. 24).

The designation of an SGC, so named, implies a broader role in implementing smart grid technologies. Many smart grid functions could be properly implemented by existing entities. However, by designating the SGC as essentially an NTA coordinator, with some ancillary functions to assist the EMT in providing smart grid education, a gap would be filled with a separate entity specifically motivated to propose transmission-system reliability solutions that are not predicated on earning a return on capital investment in transmission itself. Rather than the T&D company proposing and managing upgrade deferrals (Pomper, 2011, p. 34), which represents an inherent conflict of interest with the profit motive, an NTA coordinator would propose deferral solutions, to be compared to transmission options proposed by the T&D utility.

A wider role for an SGC might be, in a deregulated market where transmission planning and operation are significantly controlled by the regional independent system operator, as is done in New England, to also perform a similar role at the distribution level. Such an entity would be a state- (or sub-state-) level independent system operator, charged with the role of dispatching instructions sent by the regional ISO as well as operating the distribution system. The local independent system operator (a smart grid coordinator) would also be charged with the function of distribution-system planning. In such a scheme, existing T&D utilities would have the role of subcontractors carrying out the physical construction and maintenance of the T&D lines and equipment (as they do now), but would no longer be responsible for planning or operating the T&D system. Were outages to occur, the local ISO control center would dispatch repair crews by contacting the T&D utility, who would still retain ownership of the physical infrastructure. In Maine, this would take the form of the SGC’s essentially being a reformed, independent Maine Local Control Center (which is presently under the jurisdiction of CMP).

Putting aside for the moment the legal relationships and statutory authority that would have to be developed, the reason to develop such a structure would be so that system operation, and by extension system planning, would be under the responsibility of an impartial coordinator. While the local ISO could develop T&D plans itself, as regional ISOs already do for the transmission system, the T&D utility could also, having access to system operation information, propose T&D solutions, as it does now. However, modeled and considered on an equivalent basis would be NTA and NDA solutions, which could be proposed by other entities that would have access to the system-operation data necessary to that work. The aim would be to maintain a planning process in which the most cost-effective solutions – transmission or non-transmission, distribution or non-distribution – are implemented.

There are various potential challenges and pitfalls to such a scheme. Would the additional layer of independent oversight and management hamper system responsiveness? How can the issue of unequal access to information and tools necessary for planning be resolved? This question is raised in the Docket: If a plethora of smart grid data is being collected and communicated, who will have the rights to obtain and utilize what data, for what purposes? (See June 7, 2011 *Transcript of Technical Conference* in Docket No. 2010-267, pp. 27-29.) T&D companies, MLCC, and ISO-NE will all need data for operational purposes. Various retail entities (CEPs, CSPs, and TSPs), EMT, and interested consumers will also need access to certain data.

The questions that need to be addressed are: (1) What are the costs of establishing another layer of review and planning and possibly another layer of operational management by an SGC that will intercept and use certain smart grid data?; (2) What are the benefits of establishing and maintaining an SGC to undertake such functions?; and (3) Will those benefits exceed the costs? The Commission has correctly identified the questions (Docket No. 2010-267, *Procedural Order*, October 27, 2010, *Appendix One*), but unfortunately the record in Docket No. 2010-267 does not include sufficient information to provide definitive answers. In defense of the parties, much of the fault for lacking the answers is the result of ongoing uncertainty about and rapid evolution of smart grid itself. What is the smart grid and how will it take root and grow? Nobody really knows at this point. Thus, the best the Commission can do at this point in time, given the record in Docket No. 2010-267, is to move deliberately in the direction of gathering the information necessary to answer the questions. These recommendations support that process:

- Some changes to transmission planning rules and cost-allocation practices on Maine's bulk electric system (BES; i.e., the FERC jurisdictional transmission system, under ISO-NE operating rules) are needed to establish a framework that enables non-transmission alternative (NTA) options to achieve their full potential. The Commission should do what it can to ensure rules and cost-allocation practices that promote a full and fair competition between transmission and NTA solutions. This could include identifying one or more Smart Grid Coordinator entity(ies) with the motivation to actively pursue such changes on the regional and national levels.

- For the Maine Local T&D system, the Commission should review and then exercise its authority to require NTA solutions applicable to the Local T&D level to be evaluated in T&D system planning and selected when modeling determines that the NTA solutions are a least-cost option.

- The Commission should consider applying "feebate" policies for the Maine Local T&D system to encourage installing and operating resources in specific areas where the resources will produce the greatest system benefits and minimize system costs.

- The Commission should continue its efforts to begin implementing dynamic pricing, including changes to standard-offer service. The Commission should ensure that early dynamic-pricing efforts are carefully monitored and evaluated. Evaluation data should be used to inform the Commission and all interested parties prior to establishing more widespread dynamic-pricing programs.

- The Commission should not authorize cost recovery for any smart grid facilities that provide customer end-use services unless those facilities use open-systems protocols and can be made available at cost to competitive service providers.

- The Commission should not assume that the T&D company is best suited to smart grid roles involving consumer education and consumer end use. The Commission should determine what parts of the smart grid relationship with consumers are best left to competitive suppliers, and whether and how standard-offer service will need to be changed to reflect new smart grid capabilities.

- The Commission should be prepared to assign SGC responsibilities to one or more entities in the near term, as a pilot project(s), and then carefully monitor and evaluate the progress in achieving general smart grid and specific NTA objectives. If pilot projects are successful, the Commission should consider temporary or short-term SGC assignments for the purposes of consumer education, NTA identification, NTA procurement, and NTA coordination. Those efforts should also be carefully monitored and evaluated. Then and only then will it be clear whether a more permanent SGC should be established.

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