DEPARTMENT OF ENERGY
UNITED STATES OF AMERICA

Request for Information
Addressing Policy and Logistical
Challenges to Smart Grid Implementation
75 FR 57006

Comments of the National Rural Electric Cooperative Association

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Introduction

The National Rural Electric Cooperative Association ("NRECA") is the national service organization representing more than 900 not-for-profit, member-owned, member-controlled rural electric Cooperatives ("Cooperatives"). Most of NRECA's members are distribution Cooperatives, providing retail electric service to more than 42 million consumers in 47 states. NRECA members also include approximately 65 generation and transmission ("G&T") Cooperatives that supply wholesale power to their distribution Cooperative member-owners. Cooperatives provide service approximately 75% of the nation's land mass, resulting in a consumer density of just 7 consumers per mile of line, significantly less density than that of investor or municipally owned utilities.[1] Because of this low consumer density, Cooperatives have built, own and operate 42% of total distribution line-miles in the nation, yet kilowatt-hour sales by Cooperatives account for approximately 11% of all electric energy sold.

Importantly, both distribution and G&T Cooperatives were formed to provide their members with adequate and reliable electric service at the lowest reasonable cost. For this reason Cooperatives evaluate the usefulness of new technologies solely from the perspective of whether a technology will provide certain, meaningful benefits to their consumers, either by lowering costs, increasing reliability or offering new service wanted by them. The focus is on increasing efficiency and productivity in the production, delivery and use of

[1] Investor-owned utilities average 35 consumers per mile of electric distribution line and municipally-owned utilities average 47 consumers per mile.

electricity, not auctioning off scarce resources to the highest bidder. This "lens" colors the views expressed herein.

With regard to Smart Grid, Cooperatives continue to widely embrace evolving technologies and have been recognized as leaders in integrating these advanced grid technologies, particularly demand response and advanced metering.[2] For many Cooperatives, advanced metering infrastructure ("AMI"), distribution automation, and software integration are among the Smart Grid technologies that make sense today. This is because the operational benefits of AMI and other distribution automation technologies are often greater in rural areas with low population densities. As discussed in more detail later in this filing, low consumer density increases the costs of meter reading, outage response, system maintenance, and distribution system losses, among other functions. Advanced technologies help Cooperatives to address these issues, providing real, immediate benefits to consumers including lower distribution costs, fewer and shorter outages and better consumer service. Many Cooperatives also expect Smart Grid technologies will help them improve and expand on their very successful existing demand response programs, many of which have been in operation since the 1970. These "load management" programs have for decades provided Cooperatives and their members an effective physical hedge in the often volatile wholesale power market. Today, the richer data from AMI will allow Cooperatives to better measure and verify the

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[2] F.E.R.C. Ann. Rep. on the Assessment of Demand Response and Advanced Metering 8 (Dec. 2008), a*vailable at:* http://www.ferc.gov/legal/staff-reports/12-08-demand-response.pdf. *Metering, http://www.ferc.gov/industries/electric/indus-act/demand-response/dem-res-adv-metering.asp.*

results of load control and better evaluate, shape, and market demand response programs to consumers.

Definition and Scope

- **We invite comment however on whether this is the best way to define the smart grid. What significant policy challenges are likely to remain unaddressed if we employ Title XIII's definition? If the definition is overly broad, what policy risks emerge as a result? What significant policy challenges are likely to remain unaddressed if we employ Title XIII's definition? If the definition is overly broad, what policy risks emerge as a result?**

Title XIII's discussion of smart grid effectively lays out a laundry list of functions and values that smart grid could provide. That list is useful for policymakers and utilities as they evaluate their technology options and pursue a technology-modernization strategy that best meets the needs of consumers. It should not, however, be considered a definition *per se* of the smart grid.

On one hand, the list may be too broad. For example, there is significant disagreement today about how fast plug-in electric vehicles ("PEVs") will be deployed and how many PEVs are ultimately likely to be deployed in different parts of the country. The Energy Information Administration ("EIA"), for example, has predicted that only 1/2 million PEVs will be sold in 2030,[3] and that PEVs will represent only a small fraction of vehicles on the road at that time. EPRI, however, has predicted that PEVs will represent nearly half of all vehicles sold within 15 years, with a total of over 100 million PEVs on the road by 2030.[4] It would be a mistake, therefore, to define the smart grid by the degree to which it

[3] See http://www.eia.doe.gov/oiaf/aeo/demand.html.
[4] EPRI, The Power to Reduce CO2 Emissions, The Full Portfolio, 2009 Technical Report (Oct, 2009).

has facilitated the deployment of PEVs. It may be that a utility could have a very smart grid that has done little to integrate PEVs because very few PEVs have ever been deployed in that utility's territory.

The list also includes some elements that may make significant sense today for specific classes of consumers, or for consumers in certain states or utility service territories but that may not make good economic sense for other classes of consumers or consumers in other areas of the country. Some consumers, for example, may express far greater interest in "smart" appliances, consumer devices, and advanced electric storage than others. DOE should not define the smart grid in a rigid manner that disregards the differences between regions, states, utilities, and individual consumers. The list is overbroad to the degree that it includes elements for which there may be no business case in some areas or for some consumers.

On the other hand, the list may also be too narrow. We cannot predict today all of the grid, communications, or consumer technologies that may be developed in the future to provide additional consumer benefits beyond those listed by Title XIII. The industry and policymakers should not limit their vision to the horizon that is visible today.

For these reasons, NRECA does not generally focus on the term "smart grid" in internal discussions. Instead, we seek to talk about technology planning and technology modernization. We recommend that each Cooperative work to find that combination of grid technologies, communications tools, integration opportunities, and business practices that will best balance potential benefits to their consumers with the costs to their consumers of pursuing those benefits.

We also recognize that development of such a "smart grid" is a long-term, iterative process. First, few Cooperatives have the financial or human resources required to optimize their systems all at once. Instead, they must make long-term plans, rolling out new technologies, communications infrastructure, and new business practices over time. Second, at each stage in the roll-out process, each Cooperative will need to re-evaluate its options. Just as the current interest in smart grid has exploded because advances in digital technologies and communications options have brought new functions and new customer-service opportunities within reach for many utilities, future advances and cost-reductions will allow Cooperatives to take advantage of additional opportunities for improving service or better controlling costs. The "optimal" system will be a moving target and Cooperatives will need to continually reconsider their plans in light of any new options. A static statutory definition of smart grid would undermine that effort.

As DOE itself has recognized, a static definition could also hamstring regulatory and statutory efforts to promote smart grid. When the American Recovery and Reinvestment Act ("ARRA")[5] gave DOE the opportunity to fund smart grid investments, it did not require that every grant applicant incorporate all of the elements from Title XIII in their proposal in order to qualify for funding. Rather, DOE permitted utilities to request funding for discrete elements of the "smart grid," according to their individual and local needs. While Title XIII's

[5] Pub. L. No. 111-5, 123 Stat. 115 (Feb. 17, 2009).

discussion of the smart grid provided a valuable guide for the types of efforts that Congress wanted DOE to promote, DOE did not interpret that as a rigid all-or-nothing, or one-size-fits-all mandate.

DOE took the correct approach in response to the ARRA. So long as Title XIII's discussion of smart grid is considered a framework or conceptual description and not as a hard-and-fast definition, and policymakers remain focused on the business case for individual investments, then policymakers do not need to be concerned about Title XIII being either overbroad or narrow.

If, however, policymakers treat Title XIII's language as set in stone, and place the specific concepts ensconced in Title XIII ahead of individual business cases, then they are likely to encourage investments that ill-serve consumers or unduly raise costs to consumers or miss opportunities to promote investments that could further Congress's goals and consumers' interests.

- **We also invite comments on the geographic scope of standardization and interconnection of smart grid technologies. Should smart grid technologies be connected or use the same communications standard across a utility, state, or region? How does this vary between transmission, distribution, and customer-level standards? For example, is there need to go beyond ongoing standards development efforts to choose one consumer-facing device networking standard for states or regions so that consumers can take their smart appliances when they move and stores' smart appliance will work in more than one service area?**

There are three forms of standardization implicated by these questions. The first is a data standard protocol that addresses the form in which meters, appliances, and other consumer-facing devices exchange information: the common language spoken by devices. As DOE is aware, the NIST Framework and Roadmap for Smart Grid Interoperability Standards[6] ("Roadmap") identified the importance of the interface between the smart grid and the customer domain. Specifically, the Roadmap states, "The interface must be interoperable with a wide variety of energy-using devices and controllers, such as thermostats, water heaters, appliances, consumer electronics, and energy management systems. ***The diversity of communications technologies and standards used by devices in the customer domain presents a significant challenge to achieving interoperability.***" (Emphasis added.) NRECA agrees, but does not believe that DOE needs to "choose" one or more consumer-facing device communications standards at this time. Significant efforts, particularly the Smart Grid Interoperability Panel Priority Action Plans, are well underway to harmonize these standards. As discussed elsewhere in these comments, the smart grid, particularly on the consumer-side, is still in its infancy. Most consumers have not even heard of the smart grid, let alone comprehend its meaning. Therefore, there is time to let the voluntary, consensus standards process work to arrive at the optimal standard or standards.

The second is a standard "gateway" for communication. In other words, this second type of standardization refers to standardization of the devices or equipment over which utilities and other providers may communicate information to consumers and their devices. For example, some utilities will chose to communicate information via the meter, some will communicate via the internet, and some will communicate via wireless communications technologies that bypass the meter. The choice of communications medium will depend on the

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[6] See http://www.nist.gov/public_affairs/releases/upload/smartgrid_interoperability_final.pdf.

options available to the utility (for example, high-speed internet connections are not available in many areas of the country), the type of information to be communicated (for example, hourly or more frequent real-time pricing information, critical peak notifications, or direct load control signals), and cost. Standardization is impossible because no one form of communication can even function in all parts of the country, much less cost-effectively meet local needs in all parts of the country. Multiple forms of communication are often required even within a single utility service territory. This does limit the portability of those consumer devices that are designed to receive a signal through only a single gateway, but it is necessary. To maintain the portability of these devices, either the device manufacturers will need to build flexibility into their products or third party vendors will need to develop products that can re-route control or rate signals from different gateways to different devices.

The third type of standardization is markedly different from the other two types of standards and refers to the types of programs or rate structures to which consumer devices can respond. NRECA does not believe that programmatic standardization makes sense. Utilities and states need to have the flexibility to experiment with different types of programs while the smart grid is in its infancy. Some utilities or competitive energy providers may have a real-time rate structure in place; others may adopt a simpler form of dynamic pricing such as a critical peak price or peak time rebate; and others may use direct load control in addition to or in lieu of time-varying rates. Each utility, working with its regulator, will develop those demand response programs and/or rate structures for which they can demonstrate a positive business case. A consumer device that, for instance, is capable of responding only to direct load control signals or only to real-time rates will lose some functionality if moved to a different territory with a different program (a dryer may still dry clothes, but it will not be able to participate automatically in the local program). To maintain the portability of these devices, either the device manufacturers will need to build flexibility into their products or third party vendors will need to develop products that can translate different control or rate signals for different devices.

Interactions With and Implications for Consumers

- **For consumers, what are the most important applications of the smart grid? What are the implications, costs and benefits of these applications?**

For consumer-owned Cooperatives, these are threshold questions that inform each Cooperative's decisions about which smart grid technologies will be deployed. Each Cooperative, the same as other utilities, will likely arrive at different answers, in part based on how the current quality of electric service, its affordability and reliability are perceived by consumers. NRECA's Market Research division conducted a quantitative study in August 2010 to gauge consumer perceptions on a number of key energy issues, including the transition to a smarter grid. NRECA is pleased to furnish DOE with a brief presentation that includes video clips from individual consumer interviews conducted in this study.[7] Based on NRECA's research, Cooperative consumers generally have a low awareness of the concept of "smart grid" and even among those familiar with the

[7] Due to the large size of the file, NRECA is providing this presentation on a USB flash drive.

term, almost all were unable to accurately define its meaning.[8] After the smart grid concept was explained to consumers in the study, most reacted positively. The majority of the survey participants' responses can be grouped into three broad categories of perceived smart grid benefits: (1) improving utilities' efficiency and service quality, (2) helping utilities stretch their current power supply further, and (3) assisting consumers in saving money. Importantly, these consumers recognized that a smart grid application or technology need not be "consumer facing" to be beneficial to them. Therefore, the most important applications of the smart grid for Cooperative consumers are any and all the applications that can achieve these perceived benefits.

For Cooperatives, any costs incurred are passed through to consumers. For this reason, most Cooperatives are hesitant to invest in costly new technology unless and until its benefits outweigh the costs. With the first and second categories of perceived benefits noted above, some of the specific applications will be largely invisible to the consumer. For example, Cooperative X may be exploring ways to improve distribution level reliability and power quality as it sees consumers' desire for improvements in these areas rise. This Cooperative may then focus its deployment strategy to specific distribution automation ("DA") applications such as Fault Location, Isolation and Service Restoration ("FLISR") and equipment condition monitoring to help achieve these goals. Cooperative Y may choose to focus on VAR dispatch to cut costs by reducing electrical energy losses, electrical demand and capacitor-bank

[8] NRECA Market Research, Consumer Perceptions Study, August 2010 ("NRECA Consumer Study"). The study consisted of 115 one-on-one, approximately 45 minute interviews with Cooperative consumers from nine states.

inspection time while at the same time realizing power quality improvements. While both Cooperatives have made cost-effective decisions to deploy smart grid technology for DA, Cooperative X's investment may be more readily apparent to consumers who can identify service quality improvements. What NRECA's research shows is that Cooperative consumers would likely still appreciate that Cooperative Y's investments in different DA applications are still beneficial.

The smart grid applications that fall into the third category identified in the study, "assisting consumers in saving money," will obviously be more transparent to consumers and thus likely to be perceived by them as important. These applications include the presentment of more detailed energy usage data to consumers and smart grid-enabled demand response programs. Providing consumers with more information about their energy usage can empower motivated consumers to make changes in how much energy they use and when. Armed with more information about their energy use, consumers may opt to use energy when it is cheaper, conserve more energy overall, or make efficiency investments (e.g., purchase more efficient appliances, make home improvements such as weatherization, etc.) that can result in energy cost savings. The costs associated with presenting this data can vary widely, depending in large part on the currency of data to be presented (e.g., real-time or near real-time data vs. prior day or weekly data) and the capabilities of the specific AMI system and "back office" software systems with which they are integrated.[9]

[9] NRECA's MultiSpeak® interoperability specification has been instrumental in trying to drive down software integration costs for Cooperatives for the past decade.

Certain demand response programs, enabled by smart grid applications, can likewise result in energy savings for consumers.

- **What new services enabled by the smart grid would customers see as beneficial?**

Both the NRECA Consumer Study and the Touchstone Energy Study suggest that a significant number of Cooperative consumers are interested in gaining a greater understanding of energy use in the home.[10] Many consumers in both sets of research reported however that they were already engaging in a number of no/low cost ways to improve the energy efficiency of their homes or conserve energy generally.[11] A significant number of these same consumers did not believe there was much more that they could reasonably do to conserve more or be more efficient. Both sets of research concluded that there are opportunities to educate consumers about their energy use through the use of in-home displays and access (online or otherwise) to more robust data on usage patterns. In particular, having access to historical energy use online and receiving a written report that compared their energy use to similar homes in the area were both new services for which significant segments of Cooperative consumers expressed interest.[12]

[10] In the NRECA Consumer Study, participants were shown flyers of 5 examples of in-home displays and one web-based energy data tool, and many responded positively to one or more of the examples.
[11] The 2009 Touchstone Energy Study found that 88% of respondents had taken steps in the past year to reduce their home's energy use and about 40% had taken 3 or more specific steps (such as making building improvements, installing CFLs, turning off lights, adjusting the thermostat, replacing appliances, cutting back on consumption generally, etc.). Likewise the NRECA Consumer Study captured similar responses plus others such as only doing full loads in clothes and dish washers, line drying clothes, and looking at ways to reduce "vampire" loads.
[12] Receiving online access to historical energy use and a report comparing their energy use to similar homes were attractive to many consumers earn between a 7 and 8 ranking on a 10 point scale among consumers between ages 18 and 64 in the 2009 Touchstone Energy Study.

Armed with this information as well as more localized studies of their own, many Cooperatives that are deploying AMI are experimenting with the online presentment of usage data to consumers.[13] This consumer research conducted by NRECA and by Touchstone Energy Cooperative, Inc. is not unique, of course. The results of other studies and pilot programs indicate similar levels of interest for this type of data, at least initially, among consumers. The looming question is whether this interest will be sustained or fleeting. Sufficient time has not yet transpired to be able to conduct the longitudinal studies that could help determine whether new data services are perceived as beneficial to consumers over the long term.

Other new services that could be enabled in a smart grid environment are new energy monitoring and management services. These services may be provided by the consumer's utility or a third party. One frequently discussed application is the Home Area Network ("HAN") that will network the utility meter and remotely controllable devices within the home, such as a programmable communicating thermostat. While numerous HAN trials are ongoing, and others will be launching soon with the help of Recovery Act funding, we lack sufficient experience at this time to determine whether HANs will be widely accepted by consumers. Other examples of energy monitoring and management services include improvements of existing demand side management programs. For example, AMI and newer switching devices can fine tune utilities' existing direct load control programs, such that consumers are not even aware of the activation

[13] See, NRECA Comments, Request for Information, *Implementing the National Broadband Plan by Empowering Consumers and The Smart Grid: Data Access, Third Party Use, and Privacy* (filed July 12, 2010).

of load control or are only minimally impacted. While direct load control is not new, smart grid applications can drive innovation in these more traditional demand management programs.

- **What approaches have helped pave the way for smart grid deployments that deliver these benefits or have the promise to do so in the future?**

In many instances, deployments are still too new or ongoing to judge whether the approach taken was optimal. However, NRECA believes that utilities that will be most successful in their smart grid deployments will be those that make fully informed choices about costs and benefits of each technology application and give due consideration to the interests of their particular consumer base. As more fully discussed below, we know that different consumers have different levels of awareness, understanding, interest level, and motivators. Based on some of the negative experiences of early adopters of the smart grid,[14] NRECA believes that perhaps a more incremental, measured approach may be prudent. Investments and deployments should not outpace consumer benefits. Simply put, there is no "silver bullet" or one right approach that will pave the way for beneficial smart grid deployments.

- **How well do customers understand and respond to pricing options, direct load control or other opportunities to save by changing when they use power? What evidence is available about their response?**

According to NRECA's internal research, about one-third of electric Cooperatives currently offer some form of time-of-use pricing, 36% offer interruptible service contracts, 32% offer direct load control programs, and 62%

[14] See, e.g., Earth2Tech, *Smart Grid Gets Clipped in Michigan* (Aug. 23, 2010); *How to Deal With: I'm Not Paying For That Smart Meter* (Sept. 17, 2010); and *Smart Grid Woes Move to Illinois, ComEd* (Oct. 7, 2010), available at: http://gigaom.com/cleantech/.

provide financial incentives for certain energy efficiency measures (such as rebates for efficient equipment or appliances and reduced electricity rates for installation of efficient equipment or appliances). While these pricing and program options are widely available, the level of consumer participation can vary significantly from Cooperative to Cooperative. For example, Cass County Electric Cooperative, a distribution Cooperative based in Fargo, North Dakota, was honored in 2009 by the Peak Load Management Alliance with its Innovative Application of Technology Award for its "Incremental Pricing Plan." Under this plan, participating consumer members receive an LED "traffic light" device that signals when power prices change. Members can reduce their usage, initiate backup power systems or pay a higher price in response to the signal. The combined result of residential, commercial, industrial and irrigation consumers participating in this program is that Cass County can control nearly 50% of its total system load in the winter months. Great River Energy, a G&T Cooperative in Elk River, Minnesota, works with its 28 distribution Cooperatives (which combined serve a total of about 627,000 consumers) to achieve outstanding success in its demand response programs. In particular, about half of Great River's direct load control is comprised of a variety of interruptible and off-peak residential-use loads including: water heating, space heating, air source heat pumps, air conditioning (summer) and dual fuel (winter). Great River Energy is able to control more than 40% of the central air conditioners on its member lines; 140,000 out of a total of 340,000 air conditioning loads. Great River Energy has also instituted wholesale time-of-use rates (including critical peak pricing).

Distribution members of Great River Energy can then align their retail rate offerings through various time varying rates.

While these are just two examples of Cooperatives that have achieved remarkable consumer response rates to their programs, some other Cooperatives, however, have had less success. The same phenomenon of uneven levels of consumer participation is repeated in the investor-owned and publicly-owned power sectors. Numerous studies and analyses have been done to try to better understand why a particular program or pricing option was successful or not. Often these studies are limited to a particular utility, and often to a single pilot program with relatively few participants. Some studies explore consumer behavior and related factors in depth, while others focus more on the program or pricing design itself and compare responses to test and control groups. Certainly, we can glean some useful information from such studies. As just one example, the Demand Response Research Center of the Lawrence Berkeley National Laboratory ("LBNL") released a report, "PowerChoice Residential Customer Response to TOU Rates."[15] This report details the consumer behavior and usage patterns in response to a pilot time-of-use program offered by the Sacramento Municipal Utility District. In brief, 1% of consumers offered the program chose to participate. The researchers drew several conclusions about the program and its participants' experiences and motivations, including that: the initial rate offering did not attract much interest; a primary motivator of those who did participate was to save money or reduce costs; many found the rate structure complicated; only half reported saving

[15] See http://drrc.lbl.gov/pubs/lbnl-3870e.pdf.

money as a result of the program; and participants clearly understood that the reason for the TOU rate was to encourage behavioral change (that is, shifting loads away from peak times of day). Research firms have also conducted similar studies that may be useful for DOE to review.[16]

DOE could provide a tremendous resource to utilities and states that want to better understand how to design pricing structures and programs by conducting a review of currently available research findings and refreshing such research periodically as new studies become available. DOE should consider modeling this review on *Driving Demand for Home Energy Improvements* from LBNL ("*Driving Demand*").[17] This report consisted of a combination of literature review, personal interviews and surveys to glean a set of "lessons learned" from 14 energy efficiency programs. As discussed further below, of particular note is the research into consumer behavior discussed in the report, which appears analogous to consumers' likely receptivity to smart grid technologies as both are based on consumers' motivation to change their energy use. DOE could also ensure that Smart Grid Investment Grant and Smart Grid Demonstration Grant recipients who are using federal funds to deploy smart grid technology to enable new pricing and usage modification programs contribute their own research on these topics to a national clearinghouse. Presumably, the Smart Grid Information Clearinghouse is the likely repository for such an information exchange.

[16] See, e.g., E-Source's *Big Innovations for Small Customers: Utilities Experiment with Dynamic Prices for Residential Customers* (Feb. 2008) (a review of approximately two dozen utility pilot projects testing dynamic pricing offerings) and *Residential Products and Service Survey* (2010) (a survey of more than 32,000 heads of households on participation in various utility product and service offerings), available from: http://www.esource.com/Residential_Energy-Use_2010.
[17] http://drivingdemand.lbl.gov/.

- **To what extent have specific consumer education programs been effective? What tools (*e.g.* education, incentives, and automation) increase impacts on power consumption behavior? What are reasonable expectations about how these programs could reshape consumer power usage?**

NRECA has not conducted a comprehensive study of Cooperative consumer education programs specifically about the smart grid. However, as noted above, research has been conducted regarding Cooperative consumers' interest in and likelihood to participate in various energy efficiency programs. Both the NRECA Consumer Study and the Touchstone Energy Study indicate that there is considerable need for more consumer education about energy use patterns and how this can affect the cost of power – seemingly necessary precursors to heightening interest in energy efficiency or conservation. A significant portion of consumers in those studies were not fully aware of the programs that their Cooperatives offered and many consumers believed that they are doing all that they reasonably could to reduce or be more efficient in their energy use.[18]

The question remains open regarding what further information or other tools would motivate consumers to act when program offerings and incentives are already readily available in many places. The American Council for an Energy-Efficient Economy ("ACEEE") released a paper in June that sought to explore how advanced metering and customer feedback tools impacted

[18] For example, as stated above, 86% of Cooperatives offer new appliance and equipment rebates. The 2008 Touchstone Energy Study revealed that 75% of respondents were favorably inclined to replace their existing appliances before they failed and 61% of these respondents said they did not need a financial incentive to do so. In the 2009 Touchstone Energy Study, respondents whether they had taken certain steps in the past year to improve their home's energy efficiency. Replacing appliances, a water heater or an HVAC system all ranked less than 10%.

consumers' realization of energy savings.[19] ACEEE posits "feedback is proving a critical first step in engaging and empowering consumers to thoughtfully manage their energy resources." At the same time, behavioral research quoted in *Driving Demand* states that it is a myth that if people are informed they will make different choices[20] and that it is also wrong to assume that people who have financial resources will make energy improvements.[21] Both studies confirm that it will likely take a combination of education and various tools to alter consumer behavior on a significant scale. While it may be possible to draw broad conclusions about necessary elements for a holistic approach that is more likely to be successful (as proscribed for home energy improvement projects in *Driving Demand)*, it is premature to assume that sufficient experimentation has occurred to date to discover "the secret sauce."

NRECA is pleased to see that DOE is asking a question about reasonable expectations. It is instructive to take a step back and view the big picture. Remember that only about 20% of the nation's total energy consumption is in the residential building sector.[22] The average American household consumes 920 kWh in a month and pays a monthly electricity bill of $103.67.[23] Further, energy use is not top-of-mind for most consumers: "People are simply not used to

[19] See Karen Ehrhardt-Martinez, Kat A. Donnelly & John A. Laitner, *Advanced Metering Initiatives and Residential Feedback Programs: A Meta-Review for Household Electricity-Saving Opportunities*, Report No. E105 (June 2010) at: http://aceee.org/node/3078?id=131.
[20] *Driving Demand* at 28.
[21] Id.
[22] See Energy Information Administration, Average Monthly Bill by Census Division, and State 2009, http://www.eia.doe.gov/cneaf/electricity/esr/table5.html.
[23] See 2005 Residential Energy Consumption Survey, http://www.eia.doe.gov/emeu/recs/recs2005/c&e/detailed_tables2005c&e.html.

making conscious decisions about energy."[24] Indeed, "[h]ousehold energy consumption is based on "non-decisions"; people do not decide to consume a certain amount of energy, but rather they engage in behaviors and activities for other ends that have the side effect of consuming energy."[25] Any predictions of monumental potential for reshaping consumer power usage must keep these facts in mind.

- **To what extent might existing consumer incentives, knowledge and decision-making patterns create barriers to the adoption or effective use of smart grid technologies? For instance, are there behavioral barriers to the adoption and effective use of information feedback systems, demand response, energy management and home automation technologies? What are the best ways to address these barriers? Are steps necessary to make participation easier and more convenient, increase benefits to consumers, reduce risks, or otherwise better serve customers? Moreover, what role do factors like the trust, consumer control, and civic participation play in shaping consumer participation in demand response, time-varying pricing, and energy efficiency programs? How do these factors relate to other factors like consumer education, marketing and monthly savings opportunities?**

As discussed above, NRECA's Consumer Study identified a significant knowledge gap among consumers about the smart grid, which confirms a number of similar findings.[26] Further, misconceptions about the impact of steps consumers have already taken to be more efficient or conserve energy and a lack of understanding of what additional steps they can take present a significant

[24] *Driving Demand* at 29, citing Lutzenhiser, Social and Behavioral Aspects of Energy Use *Annual Reviews*. 18: 47-89 (1993).

[25] *Driving Demand* at 29 citing Sovacool, The cultural barriers to renewable energy and energy efficiency in the United States, *Technology in Society* 31(4): 365-373 (2009).

[26] See, e.g., Harris Interactive, *The Harris Polls* (Jan. 2010) (68% have never heard the term "smart grid"), http://www.harrisinteractive.com/Default.aspx?tabid=447&ctl=ReadCustom%20Default&mid=1508&ArticleId=235, and GE Energy, U.S. Consumer Impressions of the Smart Grid (March 2010) (79% of consumers not familiar with the term "smart grid"), http://itsyoursmartgrid.com/pdf/assets/resources/downloads/GE_U%20S%20%20smart%20grid%20survey%20fast%20facts.pdf.

barrier.[27] Research has also established that energy use is largely based on unconscious habit and that energy is generally considered “low involvement” service. NRECA has heard this phenomenon colorfully expressed as, “Consumers want their beer cold and the TV to work.” *Driving Demand* further discusses how information alone has little or no effect on consumer action and that different consumers respond differently to the same information.[28] Other factors can also have an impact, and point to the individual nature of consumer behavior and a need for more research in this area specifically focused on various smart grid applications. NRECA’s Consumer Study found that consumers’ trust in their Cooperative was a factor in their support of Cooperative smart grid deployments or efficiency programs. Consumer control was something some Cooperative consumers wanted; while others were more of a “set it and forget it” mindset or said they preferred to have the Cooperative do the work for them. While more data, such as through an detailed in-home display or web sites with energy usage history, appealed to some Cooperative consumers, others expressed “information overload” and found the simplest of feedback devices preferable. As noted above, the Touchstone Energy Study found that many consumers were particularly interested in getting a report that compared their home’s energy use to that of similar homes in the area, suggesting that social norms also play a role. Additionally, some consumers in the NRECA

[27] This lack of knowledge in part prompted the “Together We Save” advertising campaign by Touchstone Energy Cooperative, Inc. , which focuses on low and no cost measures to be more energy efficient in the home.

[28] *Driving Demand* at 33, 37-38.

Consumer Study expressed concerns about the environment and energy independence as motivators for reducing their energy use.

Even this brief discussion of consumer knowledge, decision-making, and habits, social norms, and other factors illustrates why it is difficult to find an optimal combination of consumer educational messages, marketing, participation incentives, and program design to successfully move consumers to some more desired behavior. Given the infancy of the smart grid, now is the time for experimentation and information exchange and to let "best practices" begin to emerge. Further, this complexity suggests that a sustained and long-term effort also will likely be required. This begs the question whether this degree of effort and the costs associated with it is worth the effort?

NRECA believes that it is necessary to remember that electricity is an essential service and that there is a limit to the amount of discomfort and inconvenience that Americans, used to a generally high level of service, will be willing to accept. Consumers are also used to reasonably affordable service throughout most of the country. NRECA does not subscribe to the philosophy that consumers should be forced to feel the pain of volatile energy prices to force behavior change. Moreover, many low and fixed income Americans, particularly renters, are not able to replace inefficient (but still functional) appliances or make building improvements that would result in marked efficiency gains. These are not so much "barriers" as common-sense reality. While consumers can be educated and motivated to make certain changes to change their energy consumption, reasonable expectations need to temper a desire to removal **all** barriers, when some are just too costly to try to remove without commensurate benefits to consumers.

For those barriers that can practically and affordably be addressed, NRECA recommends that a number of steps be taken. First, a similar analysis that leads to a set of actionable recommendations such as the *Driving Demand* report should be explored. The inputs to that analysis should include utility experiments, including those funded by Recovery Act funds. Second, DOE can ensure that the Smart Grid Information Clearinghouse is home to the results of these experiments and can encourage others conducting research (states, smart grid technology vendors, independent research firm, etc.) to use this portal as well. Third, DOE can continue to engage in collaborative outreach with state utility commissions, utilities, consumer advocates and other stakeholders to explore creative solutions.

- **How should combinations of education, technology, incentives, feedback and decision structure be used to help residential and small commercial customers make smarter, better informed choices?**

NRECA believes that with more information and experience it will be possible to discern the types of components necessary to achieve better results for consumers. However, unlike a puzzle where the pieces can only be fit together in one way to complete it, various combinations of smart grid education, technology, incentives, feedback and decision structure will be needed take into account local differences and the particular needs and characteristics of each consumer base.

- **Are education or communications campaigns necessary to inform customers prior to deploying smart grid applications? If so, what would these campaigns look like and who should deploy them? Which related education or public relations campaigns might be attractive models?**

This would appear to have a simple question, but in fact, it may not be so simple. Generally speaking, it would seem prudent to educate consumers before new smart grid applications are deployed, particularly those that would have a noticeable impact on the consumer. For example, an AMI deployment necessitates the change-out of old meters for new meters and briefly disrupts service to the consumer. Consumers, therefore, need to be notified so that they can prepare for the brief outage that will occur. However, the experience of some early adopters of smart grid technology that did engage in consumer education campaigns prior to their deployments gives one pause.[29] Was it simply the content of the communications that failed to appropriately educate consumers? Did the utilities misjudge initial consumer reactions and concerns? Did technology "malfunctions" erode consumer trust? Did too much hype inflate consumer expectations or simply create a mismatch of technology deployments and the availability of new consumer applications? Some or all of the above?

Because smart grid deployments are under utilities' control, it only makes sense that utilities be wholly or at least primarily responsible for the consumer education and communications campaigns. Further, utilities have developed various methods of communicating with consumers over the years that can be utilized in the context of the smart grid – from web sites, bill stuffers, newsletters,

[29] See, e.g., class action lawsuits filed against two utilities related to their smart meter deployments, Flores v. Pacific Gas & Electric Co., No. S-1500-CV-268647 (filed Ca. Sup. Ct. Oct. 16, 2009) and Cordts v. Oncor Elec. Delivery Co.,

annual reports, community events, social media, and much more. Utilities are thus able to continue their ongoing dialogue with consumers through multiple, existing channels. Introducing messages from others could confuse consumers, particularly if such messages lead to inaccurate consumer expectations about how and when certain smart grid technologies and applications will be deployed and what new opportunities will exist for consumers.

- **How should insights about consumer decision-making be incorporated into federal-state collaborative efforts such as the Federal Energy Regulatory Commission's ("FERC") National Action Plan on Demand Response?**

The National Action Plan on Demand Response ("NAP") is intended to be a road map for assisting states, local utilities and regions in implementing demand response by (1) identifying requirements for technical assistance to States to allow them to maximize the amount of demand response that can be developed, (2) identifying the framework for a national communications program that includes broad-based, consumer education that states and local utilities may use in conjunction with their own efforts, and (3) developing and identifying tools, best practices, resources and model regulatory provisions that can be used by regulators, utilities and consumers. The provision of resources and best practices is most critical of these objectives because such materials are fundamental to offering technical and communications assistance. Decisions on demand response and deploying smart grid technologies are too important to be made in a vacuum. In order for utilities and state regulators to make well-informed, cost- effective decisions, they need the benefit of shared insights and lessons learned about consumer participation in such programs: did consumers participate and if so for how long, what sort of messages resonated with what sort of consumer, and what were the impacts to the consumers' bills or on the amount of energy consumed? Utilities and states also need to know about tools for educating consumers: what worked and why, did consumers react to real-time pricing, did they understand what they had to do in the program and what the impact would be on their bills and their use of energy?

The NAP calls for the formation of a coalition to coordinate the implementation of the plan. The coalition will be comprised of state and local officials, utilities, consumer advocates and other industry stakeholders. Member diversity is important to the coalition's ability to provide a wide range of insights and experiential materials on consumer decision-making. NRECA has joined with others in forming such a coalition, the National Action Plan Coalition ("NAP Coalition"). At present, the NAP Coalition has begun to identify materials within its own membership as well as outside resources that can be used to inform state and local regulators in their deliberations about demand response and smart grid.

Interaction With Large Commercial and Industrial Customers

- **Please identify benefits from, and challenges to, smart grid deployment that might be unique to this part of the market and lessons that can be carried over to the residential and small business market. Please identify unmet smart grid infrastructure or policy needs for large customers.**

It is important to remember that there are two aspects to the smart grid: those elements that are on the utility side of the meter and those that are on or relate to the customer side of the meter. All customers benefit from those elements on the utility side that permit the utility to improve reliability, productivity, efficiency and power quality and better control costs. With respect to the customer-side of the meter, many commercial and industrial customers ("C&I") already have access to the kinds of functionality that are now being described as "smart grid."

Many of the tools and options that either are now or may soon be affordable for residential and small commercial customers, have long been cost-effective for many larger energy users. As a result, many C&I customers already have meters that provide them detailed information about their energy usage, devices in place to provide back-up energy and improve power quality, and energy management software and controls for their buildings or their manufacturing processes that allow them to enhance their internal efficiency and/or to take advantage of utility-run and wholesale market-run demand response programs.

Assessing and Allocating Costs and Benefits

- **How should the benefits of smart grid investments be quantified?**

If consumers are to bear the costs and risks of the technology, benefits to consumers must be determined to be certain, or at least reasonably certain, but in no case should they be speculative. Such benefits should be quantified via engineering studies or rigorous forecasts using only significant empirical data from significant, rigorous tests, demonstrations and/or historical operation data. The DOE's ARRA investment and demonstration grants should prove useful once data is available. In no case should benefits be assigned to auctioning off scarce facilities to the highest bidder.

- **What criteria and processes should regulators use when considering the value of smart grid applications?**

If the consumer is to bear the costs and risks of the technology, the benefits to the consumer must clearly and significantly outweigh the costs imposed.

- **When will the benefits and costs of smart grid investments be typically realized for consumers?**

When and how soon a consumer benefits from the costs of smart grid technologies will depend greatly on the nature of the smart grid investment, the nature of the supplying utilities' operations, the cost of power and energy, the region/climate where the consumer is located, and the options available to the utility and the consumer, among others. For Cooperatives with very low density, the operational benefits from those investments that reduce truck rolls and reduce outage times will be visible to consumers almost immediately through reduced better reliability and lower power costs. For Cooperatives with high peak power costs or high demand charges, benefits of those investments that permit the Cooperatives to shift load off of peak may be seen within a year in reduced power costs. For Cooperatives with significant exposure to market volatility, investments that permit them to shift load during high cost periods may also be seen within a year in reduced power costs.

Unfortunately, however, many of the reduced costs will show up as reduced or slowed increases in power costs. While the Cooperative may be aware of how much money the investments saved consumers, those savings will not be as apparent to the consumers who will still see higher rates. In other cases the reduced costs will not show up for many years. Some Cooperatives have adopted critical peak pricing or direct load control programs only to have them sit dormant for a year or more because wholesale market prices were low, weather was mild, and there was no economic need to operate the programs. While the investment was a good one, and will pay for itself in later years when conditions are not so salutary, the benefits will not be immediately visible to consumers.

- **How should uncertainty about whether smart grid implementations will deliver on their potential to avoid other generation, transmission and distribution investments affect the calculation of benefits and decisions about risk sharing?**

"Risk sharing" means something very different to Cooperatives than it does for investor-owned utilities. Because Cooperatives are owned by their consumers, there is no one other than the consumers to bear the cost and risk of any investment. The risk cannot be shifted from ratepayers to shareholders in a Cooperative because they are one-and-the same.

Uncertainty, therefore, requires one to ask whether to delay an investment until there is greater certainty or to invest more quickly in an effort to obtain near-term gains. To answer this question will require an estimate of the dollar value of delaying the particular investment for the forecast delay period. This is typically done via engineering studies. However, it must be understood that the benefits are directly related to the delay of the investment, and not a permanent delay. Electricity is the lifeblood of our economy. Without adequate generation, transmission and distribution, the economy will not grow.

- **How should the costs and benefits of enabling devices (e.g. programmable communicating thermostats, in home displays, home area networks (“HAN”), or smart appliances) factor into regulatory assessments of smart grid projects?**

The costs of all such devices needed to produce the cited benefits must be incorporated into the regulatory assessment, and should be compared to other options that produce the same or better consumer benefits.

- **If these applications are described as benefits to sell the projects, should the costs also be factored into the cost-benefit analysis?**

Yes. See above.

- **How does the notion that only some customers might opt in to consumer-facing smart grid programs affect the costs and benefits of AMI deployments?**

Cooperatives have a long history of successful direct control load management programs that produce certain benefits in terms of lower costs and increased reliability. Importantly these programs are voluntary, and volunteering members are provided a direct incentive to participate. Most Cooperatives that utilize such programs can control 20% or more of their peak demand, and have had no difficulty meeting this threshold (see FERC Demand Response to Congress assessing national demand response potential at 20%). Put differently, depending on what the technology is intended to accomplished, not all consumers may need to participate, and in fact, there is generally a diminishing return to the technology investment a some point well before the “everybody must participate” point. If, on the other hand, the focus is on advanced distribution operations for reliability, efficiency and productivity increases, advanced meters at (most) all locations may be valuable. In such cases the benefits of full deployment would clearly outweigh the costs, and consumer rates should go down.

- **How do the costs and benefits of upgrading existing AMR technology compare with installing new AMI technology?**

It depends on what you are trying to accomplish. For instance, if a utility has a well-functioning AMR system and wants to do a better job of outage management, adding a simple pinging function to the AMR system can be very cost effective. It also depends on other factors, such as how recently the AMR technology was installed and the degree to which the investment in that AMR has been recovered; the number of functions (such as ability to measure demand, ability to measure blinks, ability to measure voltage) that the AMR is capable of providing without an upgrade; whether the communications infrastructure presently exists to support a move to AMI, and if it does not, what it would cost to upgrade or build that infrastructure; whether other control and software systems at the Cooperative (such as SCADA, meter data management, customer information systems, billing systems, outage management systems and load control systems) would be compatible with AMI and, if they would have to be upgraded, the cost of the upgrades; the level of consumer interest in additional features that might be made possible from a move to AMI; and others.

Because of the range of factors that would go into the equation, the evaluation of the business case for the upgrade must be performed on a case-by-case basis. Generally, Cooperatives apply the 80/20 rule---if you can get 80% of the benefits you are trying to achieve for 20% of the costs, it is often better to do that, at least until something better is on the horizon.

- **How does the magnitude and certainty of the cost effectiveness of other approaches like direct load management that pay consumers to give the utility the right to temporarily turn off air conditioners or other equipment during peak demand periods compare to that of AMI or other smart grid programs?**

The question creates a false dichotomy between direct load management and AMI or other smart grid programs. First, it must be understood that much of the smart grid has nothing to do with demand response – and thus cannot be effectively compared against direct load management. Many Cooperatives have invested in AMI, distribution automation, high-speed communications, and systems integration tools – smart grid – without the present intention of using those tools to control load.

Second, direct load control can be an effective part of the smart grid. AMI can enhance existing direct load control programs, making them even more effective physical hedges in the wholesale power market. AMI, for example can give utilities greater information about the level of response they get from different direct load control signals to different customer classes – which can help improve the programs; help them trouble shoot for failures in the direct load control equipment so they can increase the level of response from existing programs; and can provide the verification of response that may be necessary for the program to participate in wholesale energy or capacity markets. AMI can also permit more subtle load control programs that permit more load to be controlled with less impact on customer comfort – for example through pre-cooling and with less risk of a bounce-back peak – through slow temperature recovery. It can also better permit utilities to design direct load control programs for commercial and industrial customers with sophisticated energy management systems.

The use of direct load control, with or without smart grid, can be far more valuable to the utility and to system operators than non-controllable demand response such as dynamic pricing. As we tried to stress earlier, “certainty” is a key ingredient in optimizing the production, delivery and use of electricity, and direct load control is certain when you need it to work---say when the temperature is 104 degrees in a heat wave. It is certain particularly compared to alternative dynamic rate structures wherein wealthy consumers can “buy-through” when it is 104 degrees outside. Several studies have pointed this out—that elasticity of demand is not insignificant---until the temperature reaches 104 degrees---when a utility operator needs it most. That is why the North American Electric Reliability Council continues to distinguish between controllable and non-controllable demand response programs.

- **How likely are significant cost overruns?**

It is virtually impossible to handicap the likelihood of cost overruns in any utility project. Nevertheless, Cooperatives have traditionally employed business practices that improve the chances that projects, including Smart Grid projects, will not incur significant overruns.[30] First and foremost is the practice of

[30] For a number of reasons, Cooperatives in many states are not subject to commission rate jurisdiction. First, Cooperatives are inherently self-regulating because they are owned and governed by their member-consumers. Because the Cooperative ratepayers and owners are one and the same, the Cooperative is presumed to act in the best interest of its members. Second, Cooperatives are required by tax law to operate at cost, allocating revenues in excess of costs back to the consumers in the form of capital credits. Thus, the concept of a “fair rate of return on rate base” is foreign to a Cooperative. Third, many Cooperatives are subject to regulation by the USDA Rural Utilities Service (RUS) on matters such as financing, plant additions, major contracts and capital credit retirements.

deploying at the pace of value. All parties involved in a project should have a clear, demonstrated understanding of the utility's "existing state" of technology infrastructure and then build upon that as is necessary to maintain the utility's ability to provide reliable cost-effective service to its consumers. Second, Cooperatives are very experienced in assessing long-term benefits of system upgrades and additions, which include taking into account a number of factors: are vendor and service provider costs transparent and verifiable; and, will the technology require upgrades before extant costs have been recovered or consumers have realized anticipated benefits? Third, vendors and service providers should be carefully selected via a competitive process and held accountable under performance-based contracts.

This is not to say that any increase in costs is *per se* imprudently incurred. Many times, cost overruns for technology deployments are caused by "scope creep." Once deployment begins, additional capability/technology is contemplated or deployed outside the original scope of work. Such additions do not represent unacceptable cost overruns if they can be shown to provide enhanced cost-effective benefits to the utility's system and consumers.

- **With numerous energy efficiency and renewable energy programs across the country competing for ratepayer funding, how should State Commissions assess proposals to invest in smart grid projects where the benefits are more difficult to quantify and the costs are more uncertain?**

With increasing frequency, state and local regulators have to consider multiple projects with different objectives but which must compete for funding. For any program, assessment should focus on the same goal: what is the most cost-effective way to effectuate policies and provide reliable service to consumers? Where the objectives of energy efficiency, renewable energy and smart grid can overlap, as is the case with ensuring generation adequacy and balanced portfolios, regulators should ascertain which projects most cost-effectively achieve those objectives, rather than focus on the type or category of the project. Conversely, if there are competing objectives and financing and resources are limited, objectives must be prioritized. For example, if a certain percentage of energy savings is mandated by a specific date, then investing in weatherization may be more prudential than upgrading to AMI.

This does not mean, however, that investments should be made only in projects where the costs are known upfront and the benefits immediate. Such thinking can be shortsighted and can preclude the ability to view systems holistically to see where, for example, long-range gains in enhanced reliability and customer control over energy usage can be achieved, but only if costs are incurred now. Development of a "smart grid" is a long-term iterative process, in part because of financing and resources constraints, but also because rolling out new communications and technology infrastructures must occur within the context of new business practices. Because Cooperatives deploy at the pace of value, the business case must come first and each phase of the project must be evaluated within that framework before it is implemented. In such cases, if it can be demonstrated that the ends do justify the means, then long-term investments in smart grid may take precedence over projects which offer less important, albeit more immediate returns.

- **What are appropriate ways to track the progress of smart grid implementation efforts? What additional information about, for example, customer interactions should be collected from future pilots and program implementations?**

It seems that practically the entire industry needs information about what motivates consumers to engage in and, most importantly, to continue to participate in smart grid programs. As is the case with smart grid technologies, there is no one-size-fits-all structure for smart grid pilots. Certainly, well-designed pilot programs can produce meaningful cost-benefit information on smart grid technologies and approaches that resonate with consumers. The trick, however, will be to design pilots that do not simply cover old ground. There should be diversity among programs, covering different regions, technologies and customer classes. Pilots that focus on urban residential consumers with dynamic pricing options will not necessarily be helpful in rural communities with large farms where the emphasis is on controlling irrigation systems to shave peaks. Currently, there seems to be a great need for pilot programs that collect information about how consumers react to different types of messaging: which messages work with which types of consumers; do consumers react more positively to, for example, feedback about neighborhood energy consumption and use of in-home devices than to statistics about environmental benefits associated with reduced energy consumption? Pilots can also gather critical information about how utilities can best educate consumers and answer their questions. In certain instances, pilots should be of longer durations than others. For example, if the goal of a dynamic pricing pilot is to chart sustained energy savings, the pilot must be long enough to ascertain whether or not any energy savings are in fact due to long-term changes in energy usage rather than the "newness" of the devices that will prompt only short-term conservation. Similarly, will the same program simply create shifts in consumer usage from on-peak to off- peak without generating any savings?

- **How should the costs of smart grid technologies be allocated?**

As a general premise, smart grid technology costs should be allocated in the same manner as any other utility investment cost-to the entities that will benefit from that technology. As discussed above, Cooperatives are owned by their consumers, so they do not have the dichotomy between shareholders and ratepayers as to rate of return on investments. Cooperatives invest in technologies intended to maintain cost-effective, safe and reliable service for their consumers-members.

With respect to smart grid, it is important to remember that there are two types of investments: those that are on the utility's side of the meter and those that are on the consumer's side of the meter. To the extent that technologies on the utility's side improve reliability, reduce system losses and serve to control costs, then all customers benefit and costs should be allocated appropriately. Conversely, the costs of technologies on the consumer side of the meter that, provide that customer with the ability to save on its energy bill, should not be socialized. Regardless of where they are installed, all technologies should be determined to produce demonstrably quantifiable benefits. Technologies should be tied to specific goals, capable of being achieved without relying upon technological upgrades or additional programs. For example, the benefits that can be achieved from AMI and new time-of–use rates will not materialize without sustained consumer participation, which in turn requires significant communications and educational programs. In this instance, the business case for implementing smart grid is rendered “untenable” without the programs for consumers, who should not have to pay for one without receiving the other.

- **To what degree should State Commissions try to ensure that the beneficiaries of smart grid capital expenditures carry the cost burdens?**

  See answer above.

- **Which stakeholder(s) should bear the risks if expected benefits do not materialize? How should smart grid investments be aligned so customers’ expectations are met?**

Because Cooperatives are customer-owned, aligning investments to meet the needs of the Cooperative and the customers are one and the same thing. Irrespective of the utility’s structure, there are two responsibilities that are inherent in aligning investments with goals and benefits. The first responsibility is to invest only in technologies that will provide value to the system and the consumers. Investments in technologies that will merely replicate existing utility services, such as replacing a dispatchable demand response program for appliances with AMI and demand pricing for the same appliances, provide little value when compared with the price tag of the technology. The second responsibility is to educate and inform customers about realistic benefits and expectations of those investments and any impact consumer participation will have on the level of benefits. Relying on consumer participation without providing consumers with the resources and information necessary to induce them to play a significant role can put the entire investment at risk. Consumers need sufficient education to understand the new technology, new rate structures (if applicable) and how their behavior and decisions will affect their energy bills. They also need to be provided the equipment necessary to participate in the programs, such as in-home displays.

It would be very difficult to provide consumers the ability to opt in or out of smart meter deployments. Such deployments require extensive planning, area by area, to ensure continued system availability (the lights staying on) and reliability. Further, utilities are deploying smart meters for a variety of beneficial uses beyond just enhancing the information that can be presented to the consumer, many of which may not be readily apparently or widely understood by consumers at this point in time. The realization of these benefits by all of the utility's consumers would be significantly undermined if some consumers declined to have a smart meter installed. To illustrate, it raises costs for all consumers when a utility must send a meter reader out to only a few residences with analog meters within a large service territory where the rest are smart meters being read remotely. It is also not cost effective for utilities to enter manually a small number of meter readings into its customer information system ("CIS") and billing system when the rest of the utility's meter readings are automatically integrated with the CIS and other systems through a meter data management system ("MDMS"). It can substantially slow outage recovery and increase the cost of responding to outages if differences in meters create blind spots in the utility's outage management system ("OMS") and geographic information system ("GIS"). Such blind spots can also undermine a utility's ability to use AMI to reduce distribution system losses, maintain proper voltage and frequency, and perform preventive maintenance.

Allowing consumers a choice in this context would introduce unnecessary burdens and costs in an already challenging process of deploying and integrating AMI with CIS, OMS and other systems. It could also undermine the business case for the investment in the smart meter technology. Uniformity across the entire system, or at least to the extent practicable, or across certain portions of their systems, allows utilities to reduce the cost per meter for acquisition, installation, and integration with other software systems. For these reasons, a determination to provide for a consumer "opt out" for smart meter deployment should not be entered into lightly, and should only be reserved for customer-side programs that the meter would enable (e.g. dynamic pricing or direct control options). It is NRECA's belief that consumers' concerns about smart meters can be addressed most sensibly by building awareness and understanding of the technology's capabilities and employing fair and reasonable privacy protections. Ultimately, a balance must be struck between consumer privacy and a utility's obligation to provide safe, reliable and affordable energy to consumers. These determinations should be made by the States or other relevant retail regulators as the bodies that are regularly tasked with such balancing decisions.

- **How might consumer-side smart grid technologies, such as HANs, whether controlled by a central server or managed by consumers, programmable thermostats, or metering technology (whether AMR or AMI), or applications (such as dynamic pricing, peak time rebates, and remote disconnect) benefit, harm, or otherwise affect vulnerable populations? What steps could ensure acceptable outcomes for vulnerable populations?**

Consumer-side technologies, such as HANs and programmable thermostats must be measured against the same ruler as other technology investments; does the benefit of installing the technology outweigh the cost?

The potential costs of the technologies, standing alone, can be minimal. If HAN-enabled chips are included in every white appliance, the added cost could be just a few dollars per appliance. It would be nearly as inexpensive to install a programmable thermostat in every new home. The potential benefit of the technology alone, however, is limited. A control chip in a washing machine or dryer does nothing unless there is either a price or control signal and a means of communicating that to the appliance. A programmable thermostat can help consumers conserve some energy – if consumers program it – but ultimately it is the policy, rate, or program that drives the consumer-side technology that has the greatest potential of providing consumers with benefits or of imposing costs on them.

Experience has indicated that vulnerable populations can benefit from some of these programs. As discussed above, Cooperatives have been successfully running demand response programs for over 30 years. Operated by Cooperatives to help them control their power costs and better manage their electric systems, those programs have saved Cooperative members, including those within vulnerable populations, hundreds of millions of dollars. There has been no suggestion that those traditional energy efficiency, load control, and voluntary conservation programs pose any risk to vulnerable populations.

More recently, some Cooperatives have begun to experiment with pre-paid metering programs. Those programs are more controversial, as some are concerned that such programs may by-pass traditional consumer protections designed to protect vulnerable customers from being disconnected inappropriately. Nevertheless, Cooperatives experience to date is that these programs are popular with participating members. While such programs must incorporate some elements to protect vulnerable consumers, they can offer vulnerable consumers significant benefit. Such programs permit participating customers to avoid the need to put down a deposit for service – a significant benefit since it can be a hardship for low-income consumers to find the cash required to pay a deposit. Pre-paid programs also give participating consumers greater information and more control over their energy usage.[31] That can help them to avoid termination for failure to pay and to actually reduce their energy usage and thus their bills. Salt River Project's experience with its pre-paid program suggests that participating consumers reduce their use by about 12%.[32]

Some Cooperatives are also beginning to develop voluntary dynamic rate options for some of their consumers. While no data is available yet from the co-op programs, some studies have indicated that low-income consumers as a class do respond to price signals and can, as a class save money.[33] Those numbers, however, are averages. While some vulnerable consumers can and will (1) understand the potential of consumer-side technologies coupled with dynamic

[31] A number of Cooperatives that offer pre-paid programs to consumers utilize a web-based data presentment tool called myusage.com.
[32] See Salt River Project's M-Power Price Plan at: http://www.srpnet.com/payment/mpower/default.aspx.
[33] See, e.g., "The Case for Dynamic Pricing," by Ahmad Faruqui, *The Brattle Group, Inc. for Smart Grid Latin America*, August 23, 2010,

pricing to save them money, (2) understand how to program the consumer-side technologies to gain those benefits, and (3) chose to do so, others will not. They may lack the capacity to understand the technology or they may be unable to take advantage of it for medical or other reasons. A policy that provides significant benefits to some within the vulnerable population may prove a burden for others.

It is, therefore, more helpful to ask whether those consumer-side technologies and specific utility policies or programs will help vulnerable **individuals** than it is to ask whether those policies help vulnerable **populations**. Asking the question that way should lead utilities and policy makers to shape policies and programs more flexibly to ensure that those who can benefit do, while those who cannot are not harmed.

A coalition of consumer organizations, including AARP, Public Citizen, Consumers Union, National Association of State Utility Consumer Advocates, and National Consumer Law Center, issued a whitepaper on The Need for Essential Consumer Protections: Smart Metering Proposals and the Move to Time-Based Pricing.[34] That paper includes several very good recommendations for ensuring that the deployment of consumer-facing technologies and associated programs do not harm vulnerable individuals. Among those, the paper recommends that: "[t]ime-of-use or dynamic pricing must not be mandatory; consumers should be allowed to opt-in to additional dynamic pricing options," and "[r]egulators should assess alternatives to smart meters to reach

[34] http://www.nasuca.org/archive/White%20Paper-Final.pdf.

the same load management goals, particularly direct load control programs." NRECA concurs.

Utilities, Device Manufacturers and Energy Management Firms

- **How can state regulators and the federal government best work together to achieve the benefits of a smart grid? For example, what are the most appropriate roles with respect to development, adoption and application of interoperability standards; supporting technology demonstrations and consumer behavior studies; and transferring lessons from one project to other smart grid projects?**

The federal government's role in supporting smart grid is distinct from that of state and local regulators, yet they must work in tandem in order to optimize smart grid benefits. State and local regulators are responsible for establishing retail rates and services in ways that optimize the provision of safe, affordable and reliable electric service to end-use consumers. Under this standard, state and local regulators will assess all smart grid costs, whether or not they are associated with wholesale or distribution technologies, and determine how best to allocate them. Federal regulators should not be concerned with how state and local regulators allocate costs. Rather, the federal government plays the lead role on a number of foundational smart grid issues that are important to optimizing smart grid benefits. Under the Energy Independence and Security Act of 2007, Congress directed FERC to adopt standards "as may be necessary to insure smart-grid functionality and interoperability in interstate transmission of electric power, and regional and wholesale electricity markets."[35] The federal government, in particular, the Department of Energy, provides financial assistance to smart grid technologies and deployment, through such programs

[35] See P.L. 110-140 (December 19, 2007) (EISA).

as ARRA Smart Grid Investment and Demonstration Grants. Lastly, both FERC and DOE will work with state and local regulators to implement the National Action Plan on Demand Response (discussed earlier), including the provision of resources and tools to assist states and local regulators in assessing smart grid projects.

- **How can federal and state regulators work together to better coordinate wholesale and retail power markets and remove barriers to an effective smart grid (*e.g.* regional transmission organization require that all loads buy ''capacity'' to ensure the availability of power for them during peak demand periods, which makes sense for price insensitive loads but requires price sensitive loads to pay to ensure the availability of power they would never buy)?**

This question really has two very different parts: (1) how can federal and state regulators work together to better coordinate wholesale and retail power markets and, (2) how can federal and state regulators work together to remove barriers to an effective smart grid. The example offered can apply to both questions.

The answer to the first question requires some foundation. We start with the basic statement that reliable and affordable electricity is an essential service necessary to the health and welfare of consumers and necessary to a strong local and national economy.[36]

The second foundation stone is that state and local regulators are responsible for structuring retail electric service in the manner that they believe can best

[36] There are some who disagree. They argue that we can no longer focus as an industry on low electric rates and reliable service. Consumer protections, they insist, stand in the way of the economic and environmental benefits that would accrue from free market interplay between wholesale suppliers, retail consumers, and competitive intermediaries. Instead of regulating the rates, terms, and conditions of service to ensure that service remains reliable and affordable, or even designing and regulating markets to ensure that they deliver reliable, affordable service, they contend that regulators should focus solely on policing the markets to preserve competition. This fundamentally different view of electricity – as a commodity rather than as an essential service – leads to very different answers on a broad range of issues, including proper retail and wholesale market design and design of the smart grid.

deliver reliable and affordable electric service. The very local nature of the decisions involved in that process was clearly demonstrated in the 1990s, when different states took varying approaches to retail competition. In the face of heavy pressure to restructure the industry, some states decided to hold fast to the regulated model; some states chose to wait and see, keeping an eye on what worked best for their restructured neighbors; and, some states moved aggressively to restructuring, but no two of those states did so in the same manner. Each state that chose to act restructured their retail markets and their regulated utilities differently to reflect their local understanding of the model that would best support the health and welfare of their consumers and best support their local economies.

Congress clearly chose to give the states and local regulators the authority to make these local decisions on behalf of their consumers in the design of the Federal Power Act.[37] In Title I of the Public Utility Regulatory Policies Act ("PURPA"), Congress has repeatedly left it to states and local regulatory authorities to decide for themselves whether to adopt federal standards relating to retail service issues such as time-of-day and seasonal rates, load management, net metering, time-based metering and communications, and interconnection of distributed generation.[38] Congress also demonstrated its

[37] Section 201(a) and (b) of the Federal Power Act grant FERC authority to regulate wholesale sales of electricity in interstate commerce and interstate transmission, but provides that FERC jurisdiction shall "extend only to those matters which are not subject to regulation by the States," and that FERC shall not have jurisdiction over retail sales of electricity or "over facilities used for the generation of electric energy or over facilities used in local distribution . . . ."

[38] See, e.g., PURPA Sec. 111, 16 U.S.C. 2621. The original 12 standards included in PURPA in 1978 were supplemented by additional standards in the Energy Policy Act of 2005 and the Energy Independence and Security Act of 2007. Each time, Congress made clear that states and

support for state control when it declined to pass much debated legislation that would have mandated retail competition.[39]

The third foundation stone is that wholesale electric markets' function should be to enable load serving entities ("LSEs") – whether competitive or regulated – to obtain and deliver to their consumers reliable supplies of wholesale electric power at rates and terms and conditions that are just and reasonable in order to permit the LSEs to meet their service obligation to end use consumers. That too can be seen in the structure of the Federal Power Act. Federal Power Act section 205 requires that all rates, terms and conditions of both wholesale sales in interstate commerce and interstate transmission be just and reasonable and not unduly discriminatory. Section 217 of the Act, added by section 1233 of the Energy Policy Act of 2005, is designed to ensure that LSEs are able to meet their service obligations. Section 217(b)(4) specifically requires the FERC to exercise its authority "in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of [LSEs] to satisfy the service obligations of the [LSEs], and enables the [LSEs] to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs."

Understanding that the wholesale markets' purpose is to meet the needs of LSEs and their consumers and that the LSEs' business structure is determined by states and local regulators is key to the question of coordination. That

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local regulatory authorities could decline to adopt the standards proposed by Congress or to adopt them in different form depending on their own judgment.

[39] See, e.g., H.R. 3790, 104th Congress (introduced by Congressman Dan Schaefer).

coordination should be designed to ensure that wholesale markets and their underlying rules and regulations are structured so as to support whatever retail market structures the states and local regulators choose to adopt to meet the needs of their consumers. The reverse is not true. State and local regulators should not be required to restructure their retail markets, the relationships between LSEs and their consumers, or the fundamental nature of retail electric service in order to make wholesale markets work more smoothly.

The parenthetical question above provides a good example for explaining this relationship. As the question states, some consumers are more price sensitive than others and might be willing to forego power at times to avoid the cost of capacity required to ensure the power's availability. Some states and local regulators may choose not to address the issue, concluding that the cost of doing so given their unique circumstances exceeds the potential value to the consumers to whom they are responsible. Some states and local regulators may choose to address the issue by requiring or encouraging LSEs to adopt demand response programs that take advantage of some consumers' price sensitivity by offering them compensation in return for their willingness to use less power when that power costs more or when capacity is scarce. The LSEs may then use those programs to reduce their capacity requirements, reduce their energy purchases, and/or to bid into wholesale markets. Some states and local regulators may choose to address the issue by permitting just one demand response aggregator to recruit consumers served by LSEs and to bid that price sensitivity into wholesale capacity and energy markets in close coordination with the LSEs. Some states and local regulators may choose to address the issue by permitting any qualified demand response aggregator to recruit consumers served by LSEs and to bid that price sensitivity into wholesale capacity and energy markets without requiring coordination. Others may bypass retail demand response efforts altogether by permitting or even requiring certain customer classes to participate directly in the wholesale capacity and energy markets.

Federal regulators should be agnostic as to which approach the states and local regulators take. Rather, they should ensure – through whatever coordination is required – that the wholesale markets can recognize the legitimacy of each approach and be prepared to accept the demand response within their market designs regardless of who aggregates the demand response resource. FERC properly followed this approach in Order No. 719, in which the Commission required each of the organized RTO markets to incorporate demand response resources offered by utilities and competitive demand response aggregators, but left it to each state or local regulator to determine whether competitive demand response aggregators would be permitted to serve those retail consumers for whom the regulators were responsible.[40]

Coordination on smart grid issues should follow very much the same pattern as coordination on retail and wholesale market issues. Each state and local regulator is likely to go down a very different path with respect to smart grid. Some states and local regulators have encouraged their regulated entities to move quickly to deploy smart grid technologies on their systems and to develop

[40] 125 FERC ¶ 61,071 (October 17, 2008).

programs that take advantage of certain potential benefits of those investments. Other states and local regulators are encouraging or permitting their regulated entities to move more slowly, developing pilots and testing different elements and functionalities of smart grid. Yet others are taking a wait and see stance. Amongst those moving forward, their regulated entities are all adopting very different grid technologies, communications networks, integration strategies, and business structures.

Coordination will be required to ensure that regardless of how the individual states and local regulators move forward, wholesale markets and wholesale regulations are designed in an open enough manner to support those local approaches. Working from the parenthetical example in the question, one can expect that some states and local regulators might approve demand response programs enabled by appliances with Zigby-enabled chips, HANs, and AMI with the capability of communicating wirelessly with the HANs, all of which communicate with competitive demand response providers through licensed spectrum. Other states and local regulators might approve demand response programs that depend upon direct load control devices operated by regulated utilities through unlicensed radio communications. None of that works effectively, however, if the wholesale market operators only accept demand response bids supported through broad-band over power line communications.

Fortunately, the necessary coordination is already taking place. At a high level, FERC and the National Association of Regulatory Utility Commissioners have a smart grid collaborative. At the detail level, the industry is working diligently through the NIST-managed standards development process to ensure that all of the parts of the smart grid – however different utilities implement it – will be interoperable.

- **How will programs that use pricing, rebates, or load control to reduce consumption during scarcity periods affect the operations, efficiency, and competiveness of wholesale power markets?**

NRECA believes that rather than asking what effect demand response programs will have on wholesale power markets, the more important question is: what effect will demand response programs have on consumers. That question would have encompassed both the impact that demand response programs can have on wholesale market behavior and the impact that demand response programs can have within vertically integrated utilities. It would also have more properly focused attention on consumers: Cooperatives ultimate concern.

We know that effective demand response programs, regardless of the mechanism used to encourage consumers to reduce demand, can provide tremendous value. For example, East River Electric Cooperative, a G&T Cooperative in South Dakota, controls over 42,000 residential water heaters and over 13,000 residential air conditioners. It also contracts for demand response services from over 1,400 irrigators and over 2,600 industrial customers for a total of more than 105 MW of load response. That has allowed East River to attain a load factor of better than 67% and has saved their consumers over $100 million since 1984. Dairyland Electric Cooperative, a G&T Cooperative in Minnesota, controls better than 75,000 water heaters, 16,000 residential dual fuel heating systems, 15,000 residential water heaters, and 8,000 residential heat storage systems. It also contracts for demand response services from 275 commercial and industrial generators, 100 peak alert voluntary load reduction C&I customers, 180 agricultural grain dryers, and 6 C&I bulk interruptible customers that are under Dairyland's direct control. Dairyland's program allows them to shave up to 81 MW off of their summer peak and up to 140 MW off of their winter peak, allowing them to save their consumers over $10 million per year.

East River's and Dairyland's savings do not arise from improvements in "the operations, efficiency, and competiveness of wholesale power markets." East River is not even in the wholesale power market. It is an all-requirements power customer of Basin Electric Power. East River is able to save its consumers money by avoiding purchasing energy and reducing its demand charges under its wholesale contract. Dairyland, which joined MISO in 2010, has been able to use its demand response to reduce the use of more expensive generating units, to reduce its reserves requirements, and to reduce its capacity costs.

It is true that demand response can also improve the operations, efficiency, and competiveness of wholesale power markets. NRECA expects that others will enumerate those potential benefits. NRECA cautions, however, that the industry has far less experience with demand response in the wholesale markets than it does with utility-run demand response programs. The industry has not yet seen what the long-run value of wholesale demand response is likely to be. The level of demand response participating in the wholesale markets and the value of that demand response has fluctuated significantly in the few years that it has been able to participate directly in those markets.

As the wholesale markets organized and PJM and NYISO developed DR programs, several thousand MW of DR volunteered to participate, mostly in emergency programs that offered some form of capacity payment. Participation in day-ahead energy programs that paid only energy prices was never very large. After a few years, possibly due to economic declines after 2001, participation in even the emergency programs began to fall. At about that point, capacity markets were formed and DR was allowed to participate. In the last few years, several thousand MW of DR have again bid into capacity markets, largely to gain the certainty of revenue from capacity payments. But, with current "ample" generation capacity, capacity prices are likely to fall, potentially causing DR to drop out of the markets again. Accordingly, NRECA has cautioned the FERC to ensure that its efforts to promote wholesale demand response programs do not undermine existing utility-run demand response programs.

It is also not clear yet to what degree demand response in the wholesale markets will inure to the ultimate benefit of consumers – particularly those consumers that are not directly participating. When a Cooperative operates a demand response program, those customers who provide demand response benefit from whatever compensation or incentive they are paid to encourage their participation in the program. Moreover, both they and all other Cooperative consumers share in the energy and capacity savings that accrue from the demand response programs. All cost savings are necessarily returned to consumers. There is no similarly direct mechanism in the wholesale market to ensure that all consumers benefit from the operational and other savings that arise from demand response participation in the markets. While some of the benefit will be paid directly to participating retail consumers and demand response aggregators, the remaining benefits may or may not be transferred from other wholesale market participants down to retail consumers.

This is not to denigrate the potential value of demand response for wholesale markets. Demand response has shown significant promise in wholesale markets. However, NRECA cautions policymakers not to limit their focus to wholesale market impacts. The focus should always be on the retail consumer. And, policymakers should recognize that demand response operated by utilities for the benefit of their retail consumers can provide tremendous benefits to those consumers. Policies adopted to promote smart grid should expressly recognize those benefits and be designed to ensure the continuing strength and effectiveness of those programs.

- **Will other smart grid programs have important impacts on wholesale markets?**

Some elements of smart grid should have the potential to increase transmission capacity in some areas of the country. Phasor-measurement units ("PMUs"), for example, may provide system operators with enough real-time data concerning transmission system conditions to permit them to grant additional transmission requests along circuits that would have been considered at capacity using traditional rating methods. That additional transmission may reduce congestion, increase competition and reduce power costs in real-time.

- **Do electric service providers have the right incentives to use smart grid technologies to help customers save energy or change load shapes given current regulatory structures?**

The answer to the question depends on the nature of the electric service provider. Electric Cooperatives, as consumer-owned, consumer-governed, not-for-profit electric utilities do have the right incentives to use smart grid technologies to help their members save energy and change their load shapes. Cooperatives' central focus is to provide their member-owners with safe, reliable electric service at the lowest cost consistent with good business practice. Success at that mission leads to satisfied consumers, stable boards of directors, and job security for Cooperative management. If a Cooperative fails to control costs, however, unhappy consumers can use the power of the ballot to elect new board members who promise to pay more attention to keeping rates affordable.

Cooperatives' performance on smart grid, demand response, and energy efficiency demonstrates that they have the right incentives. Cooperatives lead the industry in smart grid deployment. An NRECA internal analysis indicates that approximately half of Cooperatives have installed at least some AMI on their systems. As the FERC recognized in a recent report, Cooperatives are far out in front of other industry sectors in the implementation of AMI. The great majority of Cooperatives that have deployed AMI have also begun to integrate their AMI and other distribution automation technology with other systems. For example, approximately 79% of Cooperatives with AMI/AMR have at least begun to integrate their AMI/AMR systems with their CIS, 26% with their GIS, and 23% with their OMS.

Cooperatives have also led the industry in promoting interoperability of system elements. About a decade ago, the Cooperative Research Network, a NRECA's research arm, identified software integration as an emerging issue for Cooperatives. CRN convened a group of vendors who agreed to work on developing a standard specification for software targeted to Cooperatives, now called "MultiSpeak."

Cooperatives are also actively promoting energy efficiency. 96% of Cooperatives have an efficiency program in place. 70% of Cooperatives offer financial incentives to promote greater efficiency. And, 73% of Cooperatives plan on significantly expanding existing efficiency programs in the next two years.

Moreover, more than 700 electric Cooperatives are Touchstone Energy® Cooperatives[41] have been engaged for more than a year in a comprehensive, local and national advertising campaign promoting energy efficiency titled "Together We Save." [42] The "Together We Save" web site offers a wide range of energy efficiency tools, including an on-line home energy audit[43], energy saving tips and calculators, how-to videos and more. To-date, consumers have performed more than $21.5 million in energy cost-savings calculations using the on-line savings calculators on the "Together We Save" web site. Moreover, Touchstone Energy Cooperatives' have access to a number of energy efficiency

[41] Touchstone Energy is a nationwide marketing alliance of electric Cooperatives committed to providing high standards of service according to their four core values: integrity, accountability, innovation and commitment to community. For more information, see www.touchstoneenergy.com.
[42] See http://www.togetherwesave.com/.
[43] The audit tool is LBNL's Home Energy Saver. Touchstone Energy Cooperative, Inc., is a national supporter of this effort.

resources that these Cooperatives can then offer to their residential and business consumers.[44]

- **What is the potential for third-party firms to provide smart grid enabled products and services for use on either or both the consumer and utility side of the meter? In particular, are changes needed to the current standards or standard-setting process, level of access to the market, and deployment of networks that allow add-on products to access information about grid conditions?**

There is tremendous potential for third-party firms to provide smart grid enabled products and services. The utility industry is investing heavily in smart grid-related technologies today, including communications infrastructure, AMI, distribution automation devices, software, and more. With the exception of some of the software that may be developed in-house by large utilities, all of those products are coming from third party firms. Many third party firms also selling services to utilities to help them design, install, and make use of the new tools. There are also venders offering services today on the customer side of the meter, including giants Google and Microsoft.

The current profusion of products and services will continue to expand as the NIST process continues to develop new standards, as the business case for existing products and services becomes better understood, as new products and services are developed and demonstrate value, and as new and existing products and services come down in price.

Given the early stage of the "smart grid" concept and the early stage of the market for smart grid products and devices, however, it would be premature to make changes to the standards-setting process, market access rules, or

[44] See, http://www.touchstoneenergy.com/efficiency/Pages/default.aspx.

deployment processes. It is too soon to know which changes would both encourage deployment of new products and services and benefit consumers.   At this point, such changes could stifle the development of innovative new products and services even as they promote the deployment of existing technology.

- **How should the interaction between third-party firms and regulated utilities be structured to maximize benefits to consumers and society?**

There are two aspects to this question. One looks at the interaction between third-party firms and regulated utilities with respect to utility acquisition procedures. Some utilities, for example, develop software in-house while others bid the projects out to third-parties to provide a competitive option to the self-build option? Similarly, some utilities operate their own demand response program while a few allow third-party demand response aggregators to compete to provide that service on behalf of the utility? The second part of the question looks at the interaction between third-party firms and regulated utilities with respect to the utilities' consumers. In some states, for example, third-party firms offer to bid retail customers' load directly into the wholesale market while in others those third party providers must they offer their services to the utility which provides its consumers a fully bundled retail service that covers all aspects of that service including demand response services.

In either event, questions concerning how the relationship between third-party firms and regulated utilities should be answered by state and local regulators, who are in the best position to determine which structure can maximize benefits to the consumers to whom they are responsible in light of a broad range of local factors. For example, the nature of the optimum relationship could depend in part upon whether the utility service territory has been opened to retail competition, whether the utility has been restructured and sold off its generation assets, whether the utility has a retail service obligation to consumers that includes the obligation to perform risk and portfolio management on behalf of its consumers, whether the utility currently operates demand response programs and the nature of those demand response programs, and whether the utility participates in a centralized wholesale market. Given the intensely local nature of this inquiry, DOE should expressly recognize and reaffirm its support for state and local regulators' role in regulating utility acquisition procedures and governing the relationship between utilities, third parties and retail electric consumers.

- **Given the current marketplace and NIST Smart Grid Interoperability Panel efforts, is there a need for additional third-party testing and certification initiatives to assure that smart grid technologies comply with applicable standards?**

The SGIP Testing & Certification Committee ("SGTCC") is working at a very fast pace to develop guidelines for Smart Grid Interoperability Standards testing and certification guidelines. NRECA's MultiSpeak interoperability initiative is working closely with this committee and will be involved in a pilot to compare the MultiSpeak interoperability testing program with the proposed guidelines. In my opinion, there is nothing more for DOE to do. We are working closely with the SGTCC to assure the guidelines are not so onerous and expensive that it will discourage SSOs from implementing testing programs and discourage users from requiring testing in order to make implementations cost effective.

- **If there is a need for additional certification, what would need to be certified, and what are the trade-offs between having public and private entities do the certification?**

This is exactly what the SGTCC is working on. Certification is not good enough. The standards implementations need to be tested for interoperability as well as certified that the standard is utilized properly. Having third parties do the testing is a good idea. Having those testing agencies be ISO certified is the question.

- **Is there a need for certifying bodies to oversee compliance with other smart grid policies, such as privacy standards?**

If there was a certification for privacy compliance, it would be for the utility, not the standard. This seems very onerous and very difficult to enforce. Currently each state has different privacy rules and the certification would need to be re-verified every time a new software version was installed at the utility. However, privacy seems to be very important to consumers, especially for customers of the big investor-owned utilities that they don't trust.

- **Commenters should feel free to describe current and planned deployments of advanced distribution automation equipment, architectures, and consumer-facing programs in order to illustrate marketplace trends, successes, and challenges.**

Cooperatives across the nation are currently investing over $600 million in additional distribution automation, demand response and advanced metering infrastructure with funding assistance from DOE via ARRA. In particular, much of the new investment is going into end-to-end connectivity between the Cooperative's G&T, the Cooperative and its consumers---tying together production, delivery and use. Advanced distribution automation is central to most

Cooperatives efforts, as is the expansion of MultiSpeak, the Cooperative IP data standard for interoperability.

- **And they should feel free to identify any major policy changes they feel would encourage appropriate deployment of these technologies.**

Confusion continues to exist in public discourse between the very broad concepts of the Smart Grid---and those who believe the Smart Grid means only AMI and dynamic pricing. The latter, limited view of smart grid is, in some cases, clouding the enormous electric system operating benefits of bidirectional communication and control that provides certain, substantial benefits to consumers. A broader focus on the operational benefits of the smart grid, and a fuller understanding of the role that technology modernization can play when integrated into utility operations would better encourage appropriate deployment and consumer acceptance of these technologies.

Regardless of their focus, policymakers must ensure that their policies are sufficiently broad to encourage appropriate deployment of all facets of smart grid. They should not mandate specific technologies, communications media, systems integration approaches, customer-facing equipment, retail or wholesale rate structures, or demand response programs. Wholesale markets and federal policies should permit utilities, states, and local regulators to make their own with respect to these specific issues in light of local needs, interests, and concerns.

Long Term Issues: Managing a Grid With High Penetration of New Technologies

- **What are the most promising ways to integrate large amounts of electric vehicles, photovoltaic cells, wind turbines, or inflexible nuclear plants?**

With extensive use of bi-directional communications and control, intelligent sensors and distributed computing, integration of such technologies becomes more efficient and achievable without as much system redundancy. However the best approach will greatly depend on the penetration levels of different devices, which will likely vary within any particular state, utility service territory, or even individual distribution circuit. That means that different technology, communications, integration, software, and business practice solutions will likely very widely as well.

Policymakers, however, should not assume that smart grid will be the panacea for integrating these technologies. If, for instance developers build twice as much wind generation in a region, balancing area, or even individual distribution circuit than there is load, enormous problems could result, and different, heroic solutions would be required. While smart grid would be part of a solution, it would not be sufficient on its own.

- **For instance, what is known about the viability of and tradeoffs between frequently updated prices and direct load control as approaches to help keep the system balanced?**

Bidirectional communications and control technologies, intelligent sensors and distributed computing have the immediate speed to respond appropriately to rapid system changes caused by the variability of various renewable resources., Such control can and should include control of certain loads with inherent storage capability (load management). Even if prices could be updated quickly, on the other hand, use of prices to provide regulation reserves would never be as fast nor as certain as direct load control. Certainty is key.

Price-based approaches to obtaining regulation reserves could also be extraordinarily expensive and complicated. Most proponents of dynamic pricing support it as a tool for reducing peak demand. It is possible to implement dynamic pricing for that limited purpose by installing the relatively limited infrastructure required to communicate a simple critical peak alert to consumers once, on a day-ahead basis, and to collect hourly energy use from consumers on a monthly basis. This does not require particularly sophisticated AMI meters, band-width requirements are minimal, latency is not a major concern, and the metering and communication systems do not need to be extraordinarily reliable as little harm is done if some consumers do not respond to the peak price alert. A real-time pricing program implemented to support a peak load control program only requires communication of 23 additional prices each day, still on a day-ahead basis.

If, however, consumers are expected to provide regulation reserves in response to price, it will be necessary to communicate prices to them on a five-minute basis, in real-time (not day-ahead), and to meter their response nearly instantaneously to ensure that adequate response has occurred to balance the system. At that point, because the reliability of the system is at stake, customer-facing equipment and meters must be more sophisticated, far more bandwidth will be required, latency becomes a significant concern, and reliability of communications becomes paramount.

- **How do factors like the speed of optimization algorithms, demand for reliability and the availability of grid friendly appliances affect those trade-offs? What are these strategies' implications for competition among demand response, storage and fast reacting generation?**

In general they are options that, depending on costs, must be compared to each other to achieve the same objective. For instance the same battery that may make the electric vehicle cost effective could also provide non-transportation options for demand response.

It is important to remember, however, that these technologies are not just competing against each other, but with other related options. For example, if battery technology advances to the point that PEVs are an affordable option for a significant number of consumers, it will probably be less expensive to install large numbers of batteries at substations than it will be to install the infrastructure required to control millions of individual batteries in individual homes.

As always, the business case for any investment, whether in demand response, distributed storage, central station storage, or generation, will have to be evaluated on a case-by-case basis. No one approach will likely be the best choice everywhere.

- **What research is needed to identify and develop effective strategies to manage a grid that is evolving to, for example, have an increasing number of devices that can respond to grid conditions and to be increasingly reliant on variable renewable resources?**

NRECA, with DOE's agreement, is leading an industry effort to try to identify the required research. What we currently know is that what has been studied so far assumes away the problems identified by the question.

- **What policies, if any, are necessary to ensure that distributed generation and storage of thermal and electrical energy can compete with other supply and demand resources on a level playing field?**

Cooperatives have long been supportive of distributed generation technologies and storage. Many Cooperatives dispatch customer-owned generation as part of their demand-response programs. Some Cooperatives have subsidized purchases of back-up generation for their key accounts in exchange for the right to dispatch those generators when required to meet system needs. Some Cooperatives even sell small generators to residential consumers. Others have actively supported member investments in small solar hot water heaters, photovoltaic arrays, methane digesters. In the north, many Cooperatives have compensated consumers for the use of heat storage for both space heating and water heaters.

These technologies, however, are generally not ready to compete on a level playing field with central station generation and central station storage (like pumped storage). It is not government policy holding these technologies back but their inherent costs. According to Solarbuzz, the costs for DG technologies are as follows:[45]

Technology	Capital Cost	Energy Cost
Photovoltaics	$6-10,000	20-40 cents
Microturbines	$1,000-1,500	10-15 cents
Fuel Cells	$3-4,000	10-15 cents
Small wind	$1,500-3,000	5-10 cents (lower numbers associated with larger wind farms

[45] http://www.solarbuzz.com/DistributedGeneration.htm.

By comparison, consumers can purchase power from utilities at an average cost of approximately 12 cents per kWh.[46] While that cost may be higher than for some forms of generation, consumers need not make any capital outlay to take advantage of that price, they need not worry about operation and maintenance, and most importantly that price includes delivery 24-7, 365 with a reliability of 99.99%. If consumers wish to continue to take advantage of the grid's reliable service, then they will have to compare their cost of power for DG with the cost of grid power, which is less than 7 cents/kWh. If they wish to sell their power in the wholesale market, they must add the cost of transmission to their cost of generation.

In addition to their internal costs, distributed resources also suffer from higher transaction costs per unit of production. It is time consuming, expensive, and often confusing even for sophisticated electric utilities to maintain and operate generators; transact for transmission and wheeling services to deliver their product to consumers; interact with wholesale markets and figure out how best to bid their generation resources to maximize value in day ahead, real-time, ancillary services, and capacity markets; comply with FERC regulations; comply with EPA regulations; and comply with NERC reliability standards. But, they can spread the cost of the necessary staff, consulting services, and legal services across large numbers of MWHs.

Individual consumers seeking to play on that same field must spread their operation and maintenance ("O&M") and administrative and generatal ("A&G") costs across a much smaller number of kWh. And, that just became more

[46] http://www.eia.doe.gov/cneaf/electricity/epm/table5_6_a.html

difficult as Environmental Protection Administration's ("EPA's") RICE rules[47] have significantly increased the cost for many distributed generators seeking to sell output from internal combustion generators into power markets. This is also more difficult for most owners of distributed generation as electricity is not their principle product. While some large industrial customers with significant generation resources may have a full-time energy manager, most customer-generators do not. Trying to play on the same field as electric utilities is a distraction from their primary business. While they can hire an expert or an aggregator to worry about that for them, that just increases the costs they must recover from sales of their generation.

Again, NRECA is not denigrating the value of distributed generation. Under the right circumstances, it can provide significant value. NRECA doubts, however, that a perfectly defined smart grid or enabling policy will be sufficient to markedly increase the levels of distributed generation. Technology breakthroughs are needed for significant expansion in this area. Technology research and development is DOE's strong suit, so an enhanced focus on R&D for distributed generation may be a more appropriate avenue for DOE to pursue.

- **What barriers exist to the deployment of grid infrastructure to enable electric vehicles? What policies are needed to address them?**

The first and perhaps greatest barrier is the continuing uncertainty about the degree to which PEVs will become widespread. The EIA estimates that 500,000 PEVs will be sold in 2035, representing a very small fraction of total vehicles on

[47] See http://www.epa.gov/ttn/atw/rice/ricepg.html.

the road 15 years from now.[48] At that level of penetration, only a few neighborhoods nationwide are likely to reach a level of penetration that requires significant upgrades in infrastructure. Until utilities and regulators have a better sense about how many PEVs will be in circulation, where they will be purchased, and when they are likely to become common, few utilities or communities are likely to be willing to make much infrastructure investment.

It is also unclear which of several approaches to integrating PEVs will prove most effective. Utilities looking to integrate PEVs must worry about several specific impacts. At the most local level, utilities are concerned that PEVs could overload or shorten the lifespan of pole-top transformers serving a few homes or even just one home. It is not yet clear what operational rules, tools, or incentives will be required to minimize that risk and appropriately allocate the costs of any necessary upgrades. At the next level up on the system, utilities are concerned that PEVs could overload or shorten the lifespan of substations serving neighborhoods in which there may be a high penetration of PEVs – for example near a highway where PEVs are entitled to use a high-occupancy vehicle lane. A different set of operational rules, tools, or incentives may be required to minimize that risk and appropriately allocate the costs of any necessary equipment changes or maintenance. On a system-wide basis, utilities are concerned about the impact that PEVs could have on their load shape and their peak power costs. A third set of operational rules, tools, and incentives may be necessary to address that risk.

[48] See http://www.eia.doe.gov/oiaf/aeo/demand.html.

The industry must find ways to address those risks to meet their basic obligations: preserving the reliability of the system and fairly allocating costs. The most cost effective solutions may ultimately be high tech, requiring high levels of smart grid penetration in the PEVs, in homes, and in the grid, or they may be as simple as timers on garage circuits. No one knows yet, though, what the answers will be, making large infrastructure investments to support one potential answer or another extremely risky.

On top of those utility concerns, some in the industry have expressed significant interest in the possibility of (1) permitting PEVs owners to receive an appropriate bill regardless of where they charge their PEV, and (2) integrating PEVs directly into wholesale markets. The infrastructure required to accomplish those two goals may or may not be the same as required to address PEV impacts on distribution infrastructure and utility power costs. If the industry concludes that the operational challenges of reliably integrating PEVs into the grid can best be met through low-tech means, it is also not yet clear whether the added infrastructure required to pursue more aggressive goals will be worth the benefit that might be gained. Clear answers to these questions will have to wait until a number of states and utility systems have had the time to experiment with different options and those experiments themselves will have to wait until there are more than a small handful of PEVs on the road. Few significant infrastructure investments are likely to be made until after the answers have been found.

Reliability and Cyber-Security

- **What smart grid technologies are or will become available to help reduce the electric system's susceptibility to service disruptions?**

Among many existing and future smart grid technologies, load control, dynamic line rating and improved real-time data from critical field equipment are existing technologies that can help to minimize potential service disruptions.

- **What is the role of federal, state, and local governments in assuring smart grid technologies are optimized, implemented, and maintained in a manner that ensures cyber security?**

The various levels of government can assist industry by working closely with them to develop standards and best practices related to isolating smart grid equipment from a utility's most important systems; pressuring smart grid equipment manufacturers to address cyber security protection in the manufacturing process – not post manufacturing; and by developing more stringent supply chain processes.

- **How should the Federal and State entities coordinate with one another as well as with the private and nonprofit sector to fulfill this objective?**

Collaboration among these parties on smart grid cyber security concerns related to government intelligence, as well as installation and operation procedures will help ensure that government and industry are have a better understanding of each other's issues and concerns.

Managing Transitions and Overall Questions

- **What are the best present-day strategies for transitioning from the status quo to an environment in which consumer-facing smart grid programs (*e.g.,* alternative pricing structures and feedback) are common?**

The best strategy at this point in time is patience.

Smart grid is still in its infancy. Many of the technologies that will comprise smart grid are still in development or in early stages of deployment. PEVs, for example, are not yet available in many auto show rooms. Other technologies that may be part of smart grid are more mature, but uneconomic today. Residential storage and distributed generation, for example, are still far more expensive than their central station cousins. Much more research, development, and demonstration is required before wide-spread deployment of much of the future smart grid will be ready for prime time.

The interoperability and cyber-security standards required for the safe and efficient integration of smart-grid technologies with each other and with utility operations are still in development. While some have made tremendous progress over the past year, others have yet to be fully scoped out let alone developed. With respect to customer-facing applications, there still is no consensus on a single standard for communications between the meter and customer devices. There is not even consensus yet that the communications to customer devices should always come through the meter rather than the internet or the airwaves. The NIST process is working very well, but standards development necessarily requires time. DOE should support the NIST process and permit it to take the time required to develop good standards that will survive the test of time.

Regulatory policies are also not yet ready for a significant roll-out of customer-facing smart grid technologies. Discussions among federal policymakers and state regulators indicate that a number of important policies should be in place regarding consumer privacy, data access, and data security before those technologies are widely deployed. States will need to determine by law or regulation who has rights to the data, who else may access that data, under what conditions they may do so, what obligations they will have with respect to that data, and who will ensure they comply with their obligations. It will take some time for the states to reach a fuller understanding of the implications of smart grid and to enact the necessary regulatory structures in response.

The market mechanisms or utility programs required to make those customer-facing technologies useful are also not yet ready in most instances. This aspect of smart grid is something of a chicken and egg problem. Customers have little incentive to invest in customer-facing smart grid technologies unless that investment permits them to participate in a utility rate or load-control program. On the other hand, utilities have little incentive to develop alternative rate and load-control programs that rely on customer-facing technologies when few of those technologies have been installed. It would certainly help to jump start the effort if all new appliances and all new homes were equipped with the requisite technologies. But, that is difficult to do if the necessary standards are not yet in place. It is also politically difficult. Even California, which is on the cutting edge in this area, could not pass a law requiring new homes to have programmable thermostats, much less home-automation networks and controllable appliances.[49]

Finally, consumers are not yet ready for this element of the smart grid either. As we discussed elsewhere in these comments, consumer surveys and in- depth

[49] See, e.g., http://www.intelligentutility.com/article/10/08/smart-grid-city-stumbles-who-pays.

interviews with consumers indicate that most do not know what the smart grid is, or, do not believe it would be worth their while to take advantage of it, and a handful even believe it is a government plot to deprive them of their civil liberties. Yes, there is a notable contingent of early adopters that might be excited to take advantage of the customer-facing elements of the smart grid right away. But, a great deal more consumer education will be required before a large %age of consumers are ready. Further, it might be better to wait on that education process until the technology, interoperability standards, regulatory policies, and requisite programs are in place. Results like those from Xcel's Smart Grid City pilot in Boulder, Colorado suggest that it is better not to promise consumers more than the system is ready to offer.[50]

- **What has been learned from different implementations? What lessons fall into the ''it would have been good to know that when we started'' category? What additional mechanisms, if any, would help share such lessons among key stakeholders quickly?**

DOE has already taken the most important steps by creating a smart grid clearinghouse, and by committing to sharing information with the entire industry that is gleaned from the projects funded by Smart Grid Investment Grants and Smart Grid Demonstration Grants. Nothing further is required at this time. Once the clearinghouse has been up and running for a while, it will be easier to tell if further steps would be helpful.

[50] See http://www.intelligentutility.com/article/10/08/smart-grid-city-stumbles-who-pays.

- **Recognizing that most equipment on the electric grid, including meters, can last a decade or more, what cyber security, compatibility and integration issues affect legacy equipment and merit attention?**

Implementing new cyber security and privacy requirements on legacy systems would be very costly and in some cases impossible on legacy equipment. A cost vs. risk assessment should be done to make see if it is really worth the cost. Not all cyber breaches will cause safety, reliability or privacy issues that need to be mitigated. Same goes with compatibility and integration issues. Customizing the integration may be the most cost effective solution when integrating new technology with legacy systems.

- **What are some strategies for integrating legacy equipment into a robust, modernized grid?**

See the answer above.

- **What strategies are appropriate for investing in equipment today that will be more valuable if it can delay obsolescence by integrating gracefully with future generations of technology?**

Utilizing standardized implantations today whenever possible and engaging the SSO to be able to map from one version to the next and from one standard to another.

- **How will smart grid technologies change the business model for electric service providers, if at all?**

Electric Cooperatives' business model is to provide their members with safe, reliable, affordable electric power at the lowest cost consistent with good business practice. Smart grid will not change that. Rather, smart grid provides electric Cooperatives with additional tools that they can use to better serve their members' needs.

There are some that have promoted smart grid as a means of dramatically transforming the electric utility industry. Under this transformative vision, the traditional electric utility with an obligation to serve at just and reasonable rates – pursuant to the regulatory compact – would become a wires company. Retail consumers would instead receive their energy directly from a centralized wholesale market, with all of the risk and price volatility that would entail.

Supposedly, a new contingent of competitive providers would spring up to offer consumers tools to mitigate that risk and volatility. Some might offer financial products that would offer consumers a “collar” mitigating the highs and low market prices. Others would offer consumers a fixed price on a portion of their electricity needs, leaving the price of the consumers’ remaining power needs above the fixed quanta to float with the market. Another group of companies would offer customer-facing technologies that permit customers to program their appliances and plug-loads to respond to wholesale market prices according to their price preferences. Yet another group would offer to come into the consumers’ homes to program all of these devices on their behalf.

This vision may be attractive for some consumers, particularly those in restructured states who are already exposed to the risk and volatility of the wholesale market. Cooperative members, however, are not clamoring for these kinds of dramatic changes. This vision reminds many in the Cooperative community of the promises made by Enron and other promoters of retail competition in the 1990s. While retail competition may have worked for some, competitive retail providers never found it worth their while to promote their products to Cooperative consumers. That makes it difficult for Cooperative board members – also members of the Cooperative – to literally "bet the farm" on the success of the next big idea.

Those Cooperative directors like the idea that someone who is accountable to the members is responsible for providing power at a just and reasonable rate; ensuring the availability of adequate generating capacity; building or contracting for a balanced and environmentally sustainable energy portfolio; hedging against market abuses and market volatility; and building a smart enough grid that values both the broad risk management and operational benefits of the smart grid.

NRECA has not asked DOE or other policymakers to choose between the Cooperative vision and the transformative vision of the smart grid. Rather, NRECA has repeatedly argued that the term "smart grid" should be defined broadly enough to permit it to go down both roads, depending upon the judgment of state and local decision makers. Just as some states were able to move down the path towards retail competition while others were free to preserve their traditional regulatory and utility structure, so should states be able to make same decision with respect to smart grid.

- **What are the implications of these changes?**

The implications of the changes differ depending on the road that an individual state or local regulator chooses to follow.

There will not be any dramatic implications if a state or local regulator sees the smart grid as a collection of grid technologies, communications tools, integration opportunities, and business practices that permit utilities to improve the quality and reliability of electric service while better controlling costs. The utilities those regulators oversee will engage in careful long-term technology planning in order to modernize their systems and their processes in the manner that best balances the cost of change with the benefits their consumers will gain from those changes. While consumers may see new service options, improved reliability and power quality, and lower rates (or slower growth in rates), the consumers' overall relationship with their utility, the utilities business model, and the regulators' role and responsibilities will not change much.

There will, however, be significant implications for those state and local regulators that choose to follow a more transformative vision of smart grid; a "prices-to-devices" vision under which the smart grid permits the direct integration of retail consumers into wholesale markets and permits consumers to "choose" their level of reliability and power quality. In this vision, the consumer pays the wholesale market price for electricity during each hour (or shorter period) of the day. The utility is no longer obligated to manage a portfolio of resources on behalf of its entire consumer base in order to minimize its exposure to wholesale market risk and volatility.

Because the utility is no longer in the business of providing risk and portfolio management on behalf of its consumers, it would have no reason to own generation or enter into long term contracts for energy and capacity. It would become a pure wires company, delivering power to consumers that they have purchased out of the wholesale market or from another third party that has stepped in to provide the services that the utility no longer provides.

In this model:

- There is no state or locally regulated entity obligated to provide power at just and reasonable rates and there is no state regulated entity obligated to hedge against the risks of market volatility and market abuse;
    - If competition in the wholesale market does not adequately drive power prices down to marginal cost on a consistent basis, customers will pay more;
    - If wholesale market prices swing dramatically, consumers will be directly exposed to that volatility. Consumers could have significant challenges managing that volatility if a secondary market of competitive third party providers does not spring up to provide the risk and portfolio management services that many utilities provide today under the regulatory compact. If third party providers do offer service but lack the efficiencies of scale, scope, and integration enjoyed by utilities today, the cost of hedging will rise;
    - Customers will pay the marginal price for power in every hour (or shorter period) and will not benefit from average cost prices – i.e., they will pay gas-generation prices for power produced by depreciated coal and nuclear plants whenever gas is at the margin, even if they paid the capital cost of the baseload plants as part of their historical rate structure. Retail marginal cost pricing would represent a significant departure from historical practice;

- There is no state or locally regulated entity obligated to ensure that sufficient generation capacity is constructed and maintained;
    - If the market does not elicit sufficient resources, reliability will be preserved by raising prices in the wholesale market (scarcity pricing) until enough consumers respond by reducing load to balance supply and demand;
    - This is described as offering consumers the option of choosing their level of reliability, but more accurately reflects the rationing of scarce resources by price – a dramatic change in the way most states and consumers view electricity; and
    - If enough consumers do not "voluntarily" conserve in response to high prices, system operators will be required to shed firm load;
- States and local regulators no longer oversee the portfolio of resources constructed to meet the needs of their consumers to ensure that there is an efficient and sustainable balance of resources;
    - If the market does not attract an efficient balance of resources, it could experience significant volatility and price increases as it becomes overly dependent on one resource or another;
- Utilities no longer benefit from the efficiencies of integration which allows many utilities today to plan their technology modernization efforts and other business practices in a manner that co-optimizes their investments to maximize both power supply and power delivery benefits;

- Utilities would have to invest in sufficient grid technology and communications infrastructure and consumers would have to invest in sufficient in-home technology to permit “prices-to-devices” to function effectively;
    - If the industry moves to “prices-to-devices” without the devices or adequate communications to those devices, consumers will face more volatile prices without the tools they would need to respond;
    - If the cost of the infrastructure required to move to “prices-to-devices” exceeds the savings enabled by the investment, then consumers will also experience higher prices;
- Regulatory authority over many aspects of electric service that are regulated today by the states would shift to the FERC because they would relate to wholesale markets and not to bundled retail electric service and electric distribution.

Conclusion

NRECA sincerely appreciates the opportunity to comment on the Department’s Request for Information. If there are any questions concerning NRECA’s comments, please contact any of the staff below immediately. NRECA would be happy to offer additional information on any of the matters raised in the RFI.

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