CALIFORNIA ENERGY COMMISSION

In the Matter of:	)	
	)	
2008 Rulemaking on Load Management Standards	)	Docket No. 08-DR-01
	)	
Implementation of – Public Resources Code § 25403.5	)	
	)	

POST- WORKSHOP COMMENTS OF CURRENT GROUP, LLC

CURRENT Group, LLC ("CURRENT"), a privately-held company headquartered in Germantown, Maryland, provides a high-speed, low-latency, two-way communications network and embedded sensing with distributed processing, which is installed on the existing electric distribution network, along with a 24x7 network management and analytic software platform, to create an efficient, automated "Smart Grid."[1] CURRENT appreciates the opportunity to submit comments to the California Energy Commissioner ("Commission") in response to comments made by participants that the April 29, 2008 workshop.

CURRENT, as well as the Electric Power Research Institute (EPRI), the U.S. Department of Energy (DOE) and the Commission itself, believes that a Smart Grid requires high-speed communications and sensors embedded throughout the distribution network. Advanced Metering Infrastructure (AMI)-only systems are typically designed to read meters once a day, and have limited communications capabilities. Due in part to the increasing awareness of the environmental impact of electric power, the requirements for the

[1] Additional information about CURRENT is available at www.currentgroup.com.

communications infrastructure have increased and will continue to increase greatly. AMI systems lack this bandwidth, are not upgradable to higher bandwidths without replacing the meter, and thus AMI-only systems should not be considered as an incremental step towards a Smart Grid. Ultimately, as many others commented during the workshop, a Smart Grid is best defined by how it behaves in real-life situations, rather than by the specific technologies used to create that behavior.

I. DEFINING THE SMART GRID AND ITS BENEFITS

As many of the speakers at the April 29, 2008 workshop noted, a central question lies in how to best define what a "Smart Grid" consists of. Several central characteristics emerged, including: (1) self healing and adaptive; (2) integrated across the entire utility functionality; (3) optimizing grid operations; (4) automating distribution; (5) secure; (6) interacting with and empowering consumers; and (7) predictive.[2]

A Smart Grid consists of a network of advanced sensors capable of collecting and monitoring data from the substation through transformers, meters and other electric distribution devices along power lines, all connected through a high-speed and low-latency communications system and a distributed computing system capable of real-time analysis and event prediction. A Smart Grid goes beyond the capability of an AMI system and provides:

- Advanced distribution asset monitoring to accurately identify potential asset failures prior to an outage;
- Real time System Optimization to minimize the power needed to run the grid, reducing both cost and environmental impact;

[2] *See* Mike Gravely's presentation at 7, Eric Lightner's presentation at 17; Walt Johnson's presentation at 2, and Richard Schomberg's at 4 (Apr. 29, 2008 Workshop).

- Automated fault analysis from across the distribution grid to accurately identify where and in many cases, why an outage has occurred;
- A dynamic network model mapping homes to transformers to feeders allowing for improved system planning, and advanced consumer-focused demand response programs;
- An advanced in-home energy management capability that can be remotely managed in real-time; and
- The real time bandwidth necessary to aggregate and manage Renewables, Distributed Generation and Plug-In Hybrid vehicles, allowing these alternatives to replace conventional coal fired power plants.[3]

A truly "smart" electric distribution network has three key components: (1) high-performance communications capable of moving large amounts of data both "upstream" and "downstream," so that the utility can both monitor and control equipment throughout the electric grid in real time; (2) advanced sensing capability embedded throughout the network and capable of providing real-time information about the grid's condition and operations; and (3) enterprise systems that can collect and analyze the multiple streams of data coming from the grid, integrate them with existing utility systems, and deliver actionable information to the utility in usable forms.

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[3] For example, the AMI Use Cases prepared by Southern California Edison (SCE) to determine AMI system requirements, specifically reject the use of the AMI system to manage distributed generation serving more than one customer for a number of reasons, including the need for real time communications which is not provided by the AMI system. See SCE AMI Use Case: D3 - Customer Provides Distributed Generation at 7, (Apr. 18, 2006). The recent report for the California Energy Commission on the Value of Distribution Automation, prepared by Energy and Environmental Economics, Inc. (E3), and EPRI Solutions, Inc., stated that the value of such distributed electric storage capable of being managed in real time (such as a battery or plug-in vehicles) would be increased by nearly 90% over a similar asset that is not connected by a Smart Grid. *California Energy Commission on the Value of Distribution Automation, California Energy Commission Public Interest Energy Research Final Project Report* at 95 (Apr. 2007) (*CEC Report*).

EPRI,[4] the Modern Grid Initiative sponsored by the Department of Energy (DOE)[5] and the Commission[6] have put forth similar definitions. Once a Smart Grid is deployed, it should be capable of monitoring and controlling every element (transformers, capacitor banks, etc.) on the electric distribution network all the way back to the substation, as well as detecting potential problems with the wires themselves, including underground cable faults. It should also extend through the meter and into the home: "The key issue here is that utility data communications networks that support advanced utility analytics must be TCP/IP-enabled. This provides the necessary flexibility and interoperability to support sensor data transport, network management, data security services support and smart device management."[7]

The system must be predictive, able to detect potential equipment failures, stray voltage situations or underground cable faults, thus improving system reliability and

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[4] EPRI refers to the Intelligent Grid, or Smart Grid, as a power system that can incorporate millions of sensors all connected through an advanced communication and data acquisition system. Such a system will provide real-time analysis by a distributed computing system that will enable predictive rather than reactive responses to blink-of-the-eye disruptions and is designed to supports both a changing generation mix in a carbon constrained world, and a more effective and efficient participation by consumers in managing their use of electricity. *See* Michael W. Howard, Ph.D., P.E., Senior Vice President, R&D Group, Electric Power Research Institute, *Facilitating the Transition to a Smart Electric Grid*, Testimony Before the House Energy and Commerce Subcommittee on Energy and Air Quality (May 3, 2007).

[5] The DOE Sponsored Modern Grid Initiative identifies a Modern or Smart Grid as having five components, Integrated Communications, Sensing and Measurement, Advanced Components, Advanced Control Methods and Improved Interfaces and Decision Support. It states "[o]f these five key technology areas, the implementation of integrated communications is a foundational need, required by the other key technologies and essential to the modern power grid." and that "[h]igh-speed, fully integrated, two-way communications technologies will allow much-needed real-time information and power exchange." A Systems View of the Modern Grid at B1-2 and B1-11, INTEGRATED COMMUNICATIONS, Conducted by the National Energy Technology Laboratory for the U.S. Department of Energy Office of Electricity Delivery and Energy Reliability (Feb. 2007).

[6] The *CEC Report* states that sensors are the next basic requirement for virtually all Distribution Automation applications: "communications is a foundation for virtually all the applications and consists of high speed two-way communications throughout the distribution system and to individual customers." *CEC Report* at 51.

[7] Technology Support for Utility Analytics, Jeffrey Taft - Lead Intelligent Utility Network Architect, IBM Global Business Services, IBM Application Innovation Services (now with Accenture) (May 2007), http://www.utilitiesproject.com/documents.asp?d_id=4298.

safety.[8] The system should allow network monitoring that detects problems before they cause power outages, safety hazards or system quality problems, and also provide power outage and restoration detection as outages occur.

As the Commission recognized in its *2007 Integrated Energy Policy Report (2007 IEPR)*, electric distribution networks are aging and facing increasing strain, and existing grids are one-way systems that lack self-healing, monitoring and diagnostic capabilities.[9] EPRI estimates that power outages and "blink of the eye" power quality disruptions cost U.S. businesses at least $100 billion per year.[10] A truly Smart Grid therefore can monitor in real-time and manage virtually every piece of equipment on the electric distribution network to optimize efficiency on the network and perform real-time power outage *avoidance* as well as real-time pin-point outage and restoration detection.

Smart Grid takes the "guess work" out of outage and restoration detection. A Smart Grid can provide utilities with real-time actionable intelligence about their networks that can be used to prevent such costly disruptions, reducing their costs to energy users by up to 87%.[11] Power system maintenance crews – which themselves are aging, with as many as 40% or more of such workers retiring over the next 10 years – will know exactly where and when to go to repair the distribution grid. Technicians can expedite power restoration to

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[8] For example, Oncor, which has the world's largest Smart Grid has stated, "Oncor is able to monitor its electric delivery system, obtaining a steady stream of data that can be analyzed for potential problems. Once a problem is pinpointed, Oncor dispatches operations personnel to investigate the irregularity before it can become an outage or other service issue. Issues are often resolved before consumers even realize that there was a problem." Oncor Press Release quoting Jim Greer - Senior VP of Asset Management and Engineering (Sept 19, 2007).

[9] *2007 Integrated Energy Policy Report* at 202-205, CEC-100-2007-008-CTF, California Energy Commission (Nov. 2007) (*"2007 IEPR"*).

10 http://www.energyfuturecoalition.org/preview.cfm?catID=57 (citing EPRI estimate).

[11] *See Electricity Sector Framework for the Future: Achieving the 21st Century Transformation* at 42, EPRI, (Aug. 2003) (*"EPRI Report"*), available at: http://www.globalregulatorynetwork.org/PDFs/ESFF_volume1.pdf.

customers through remote management of switches and other utility infrastructure. Power crews also will know in real time, and to what extent, restoration has occurred with each network repair performed, which further saves on labor costs, as consumers generally do not call to notify the utility of effective power restoration.

Smart Grid greatly reduces the electric energy that is lost before it reaches the consumer due to network faults or inefficiencies. Federal Energy Regulatory Commission (FERC) Commissioner John Wellinghoff testified to Congress in May 2007 that "if we could make the electric grid even 5 percent more efficient, we would save more than 42 gigawatts of energy: the equivalent of production from 42 large coal-fired power plants. Those are plants that we would not need to build and emissions that we would not produce."[12] This would equate to saving of approximately 275 million tons of CO2 annually across the U.S.

A utility therefore must be able to monitor and control capacitor banks, transformers, switches, substations and other critical infrastructure, manage demand response programs for end users, and measure and coordinate available distributed and renewable energy sources, in addition to providing AMI/Smart meter functions (including reads to one minutes intervals, remote connect and disconnect, voltage limiting, pre-pay, and multiple pricing functions made possible by a high-speed and low-latency communications system).

As the Commission recognized in its *2007 IEPR,* through increased use of distribution automation and communications and controls, utilities will no longer have to wait for customers to let them know there is a problem. New technologies, including Advanced

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[12] Prepared testimony of John Wellinghoff, Commissioner - Federal Energy Regulatory Commission, to the House Energy and Commerce Subcommittee on Energy and Air Quality (May 3, 2007).

Distribution Automation (ADA) [a component of the Smart Grid], will give distribution grid operators the ability to detect and respond to problems quickly and safely. Being able manage the grid in real time will allow utilities to better assure grid reliability, security, efficiency, affordability and power quality. These new systems will feature the free exchange of information between the utility and the customer and the customer and the utility.[13]

II. THE WORLD HAS CHANGED AND SO HAVE THE REQUIREMENTS FOR AMI

A number of significant requirements have emerged since California utilities and the California Public Utility Commission (CPUC) began studying AMI in 2002, including the realization of the significant impact of greenhouse gases.[14] Congress and others have since recognized that a Smart Grid reduces the total amount of power used,[15] and have recognized the need for changing requirements, in large part due to the environmental impact of electric power. While the 2005 Federal Energy Policy Act (EPACT) emphasized the use of AMI infrastructure and demand response, primarily to address pricing and reliability at times of peak usage,[16] Congress, with the federal Energy Independence and Security Act of 2007, has identified Smart Grid as a national policy and changed the requirements:

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[13] *2007 IEPR* at 201.

[14] DOE studies show that electricity generation and distribution produces 40% of all Carbon dioxide (CO^2) emissions in the United States. CO^2 emissions from power plants climbed 2.9 percent in 2007, the biggest single-year increase since 1998, according to a recent analysis of data from the Environmental Protection Agency (EPA) by the nonprofit and nonpartisan Environmental Integrity Project (EIP). Currently, the single largest factor in U.S. climate change pollution, the electric power industry's CO^2 emissions have risen 5.9 percent since 2002 and 11.7 percent since 1997. Environmental Integrity Project Press Release (Mar. 18, 2008).

[15] EPRI projects that Smart Grid-enabled electrical distribution could reduce electrical energy consumption by 5 percent to 10 percent and carbon dioxide emissions by 13 percent to 25 percent. *EPRI Report* at 42.

[16] In addition, the Federal Energy Regulatory Commission report on the Assessment of Demand Response and Advanced Metering, mandated by EPACT, mentioned the environmental impact of demand response and AMI only as an "additional benefit," with the caveat that "the importance and perceived value of each of these

(footnote continued)

> Deployment of 'smart' technologies (real-time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices) for metering, communications concerning grid operations and status, and distribution automation.[17]

One result of the environmental impact is that a requirement for the real-time optimization of the grid, based on millions of data points, will emerge in much the same way that telecommunication systems operate. The CEC Report estimates such optimization could reduce distribution grid line losses by 15% or more and save 500,000 tons of CO^2 annually.[18] Similarly, a study at Hydro Quebec quantified those savings at two billion kWh.[19]

III. AMI IS A COMPONENT OF A SMART GRID BUT NOT NECESSARILY AN INCREMENTAL STEP TOWARD A SMART GRID

"AMI only" technologies must be distinguished from a true Smart Grid. Smart Grid surpasses many of the AMI capabilities deployed thus far. Unlike metering-only systems, a Smart Grid dramatically improves the efficiency and reliability of the entire grid, which helps to greatly reduce electricity consumption and greenhouse gas emissions. Moreover, metering-only solutions are not an incremental step toward Smart Grid; investment spent on advanced meters will be stranded later if the utility upgrades to Smart Grid.[20] While Smart Grid requires more upfront capital investment than advanced meters, the asset management capabilities of Smart Grid, coupled with a two-way broadband communications

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(additional) benefits is subject to debate." *Assessment of Demand Response and Advanced Metering* at 11, FERC, Docket No. AD06-2-000 (Aug. 2006) ("*FERC Assessment*").

[17] HR6, Title XIII – Smart Grid, §1301 (6).

[18] *CEC Report* at 75 and 111.

[19] *Id.* at 75.

[20] *See Getting Smart* at 68, Robert Robinson, Jr. and James C. Henderson, Electric Perspectives (Sept. /Oct. 2007).

infrastructure, provide exponentially more benefits, ultimately providing net savings to both utilities and rate payers.[21]

In contrast to the high-speed, low-latency communications required for a Smart Grid, FERC defines an AMI system as a metering system that records customer consumption {and possibly other parameters} hourly or more frequently and that provides for daily[22] or more frequent transmittal of measurements over a communication network to a central collection point. FERC estimates that 80% of the cost associated with an AMI project is associated with the meter, installation, IT integration and project management and only 20% is associated with the communications network.[23]

Many AMI systems are designed for once- a-day communication, and thus have very limited communications bandwidth. The best-in-class AMI focused solution (typically wireless mesh) operates at approximately 28.8 to 56 kbps (the equivalent of dial-up modem speeds that were outdated 10 years ago). This is further emphasized by a recent AMI vendor presentation that showed their system could send a one way message to 3 devices per second. On the typical 2,000 meters per collector, this equates to being able to send a one way message in slightly over 11 minutes to all the devices and another 11 minutes to get a message back (assuming times are not further delayed by meter reading activity, congestions or interference).

AMI only solutions are appropriate for what they were designed for, replacing

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[21] *Id.*

[22] Indications are that SCE is doing daily reads. *See* EDISON SMARTCONNECT™ DEPLOYMENT FUNDING AND COST RECOVERY Errata to Volume 2: Deployment Plan (Dec 5, 2007).

[23] *FERC Assessment* at 35.

meter readers with a once a day meter reading solution and providing limited, additional insight into customer outages. KEMA, a leading industry consultant noted:

> The immediate requirements of AMI may not in themselves require high performance embedded communications. This can lead to a choice of wireless infrastructure as having lowest initial costs and comparable or lower ongoing costs. However, these technologies are not 'future proofed' and may not be able to support some of the capabilities described above as tied to high performance, ease of getting beyond the meter, and detection of power line anomalies...[24]

For a Smart Grid to achieve its benefit, it is important that the network offer sufficient communications bandwidth to accommodate not only AMI, demand response and other existing programs, but also to enable yet-to-be-developed technologies and capabilities offered by any provider. Using non-proprietary communications technology, such as IP, enables ready integration with existing home networking applications and devices that consumers can use to monitor and control their energy usage. By overlaying a high-speed, two-way network on the electric distribution grid, utilities cannot only read meters more frequently than is possible with low-bandwidth AMI-only solutions, but also deliver real-time pricing and information about energy use to in-home displays, giving consumers better control of their bills and the means to reduce their electric consumption.

A Smart Grid connects advanced meters, smart thermostats, smart appliances, load control devices and distributed generation and renewables in homes and businesses directly to the utility through a high speed communications network. This enables meters and other devices to respond to information about prices and reliability events as they change in real-time. And because most consumers do not have the time or desire to monitor and

[24] *Enabling the Power Plexus*, KEMA, Aug. 2007.

respond to such information themselves, a Smart Grid allows the utility to administer sophisticated time of use contracts not possible with more limited technologies. For example, rather than simply directing all air conditioners in a given vicinity to cycle off for some defined time period, a Smart Grid-enabled system could direct 100,000 specified air conditioning units to allow the temperatures in their premises to increase by three degrees – and then could verify, in real time, the precise level of electric demand that was shed as a result of that action. In Texas, the independent electric retailers believe features like this would allow them to offer innovative rate plans that would appeal to consumers. Automated in-home energy management systems continue to evolve and the most sophisticated of these systems already require a high speed communications path.

IV. A SMART GRID NEEDS TO CONNECT THE CUSTOMER TO THE MARKET

A Smart Grid should facilitate an end-to-end supply chain, engaging the consumer in the market by creating a real time interactive two-way communications path along the distribution grid as well as to virtually every home and business. As the Commission recognized in its *2007 IEPR*, encouraging greater use of price-responsive demand response programs, coupled with advanced metering infrastructure, will help reduce demand "peaks," improve service quality, and avoid incremental generating capacity costs, energy production costs and transmission and distribution capacity costs.

Smart Grid greatly expands the capabilities and benefits of demand side management (DSM) and other efficiency programs. Smart Grid enables real-time, two-way communications to smart meters, smart thermostats, smart appliances and in-home energy usage displays. A Smart Grid connects advanced meters, smart thermostats and other load control devices in homes and businesses directly to the utility through a high speed communications network that overlays the electric distribution system itself and extends from the substation to virtually every electrical outlet in customers' homes and businesses.

By enabling 15-minue (and shorter) interval data and "on-demand" meter reads to the consumer, Smart Grid makes possible innovative demand response and real-time pricing programs that are not feasible using more limited technologies. Meters and other end-user energy management devices are able to provide consumers with information about wholesale prices and reliability events as they change in real-time. More importantly, this information is available anywhere (for instance at the office, over the internet) as opposed to being limited to an in-home device. For those consumers who do not have the time or desire to monitor and respond to such information, the utility can administer time-of-use contracts under which demand resources (e.g., air conditioners, pool pumps, lights) can be turned down by a predetermined amount, or even shut off completely for a short period in response to peak pricing events or load management programs.

With a Smart Grid, DSM programs can confirm, simultaneously and in real-time, the precise reductions in load occurring at an individual residential customer levels all across the distribution grid. Utilities can also centrally monitor and manage literally millions of DSM devices through a single, centrally located "head-end" software system. The unprecedented scale and scope of such DSM programs means that commercial/industrial and residential users, including low-income customers, can be aggregated into substantial blocks of load reduction.

In summary, the communication to the customer needs to be received in the appropriate time and more importantly; the utility needs to know that the desired action occurred. Real-time, interactive communication is an increasing need as the in-home energy management systems and appliances become increasingly smart and able to interact with the markets in real time. This is also important in the case of the management of distributed generation or renewables. As part of the connectivity, it is also important that the technology allow for a managed network that assures the customer is actually receiving the pricing or other signal. Without this capability, imagine the difficulty in implementing time-of-use or other rate plans when a customer complains to the California Public Utility Commission (CPUC) that s/he did not receive the signal, and the utility has no way of verifying whether or not they did.

V. CREATING A "FUTURE-PROOF" SMART GRID

A central question facing policy makers in California is how to ensure that the ratepayers fund a deployment with the most functionality and longest life. AMI systems currently being contemplated and/or deployed by the state's utilities arguably will be not scalable in the future. Investments made today in AMI-only solutions that are solely capable of low-bandwidth connections to meters and a limited range of other devices on the customer side of the meter are not readily upgradeable to a true Smart Grid. Such investments, whose business case (for example, in the case of PGE, the business case is based on a 30-year meter depreciation life) could easily become stranded cost requiring adoption of new and better technology.

In addition, much of the AMI technology is new and many of the potential issues have not been vetted through wide scale deployment. For example, two manufacturers of equipment that utilities nationwide are using in their AMI deployments, Itron and Cellnet and Hunt, recently asked the Federal Communications Commission (FCC) to change the long-established rules on spectrum etiquette for the unlicensed radio frequency band in which they operate due to interference issues.[25] In seeking to change what the rest of the communications world views as a successful policy, Cellnet and Hunt informed the FCC that "[t]he undesirable effects of such interference cannot be disputed and should not be understated. For its automatic meter reading operations, electric utilities may be positioned to suffer periods where key operational and load control data cannot be received. SCADA operations may also be impacted."[26]

Further, a system without the capability to communicate with embedded sensors throughout the grid and without sufficient bandwidth to carry the rich data streams generated by such sensing cannot avoid becoming stranded by evolving to offer those resources. Instead, installing smart meters that rely on low-bandwidth solutions will generally preclude creation of a Smart Grid during the fifteen to twenty-year or longer life of those meters.

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[25] Comments of Itron at p. 3-4, *In re Modification of Parts 2 and 15 of the Commission's Rules for Unlicensed Devices and Equipment Approval*, ET Docket No. 03-201 (Oct. 15, 2007); Comments of Comments of Cellnet Technology, Inc. and Hunt Technologies, LLC at p. 7, *In re Modification of Parts 2 and 15 of the Commission's Rules for Unlicensed Devices and Equipment Approval*, ET Docket No. 03-201 (Oct. 15, 2007); *See also* Reply Comments of Cellnet Technology, Inc. and Hunt Technologies, LLC at p. 1, *In re Modification of Parts 2 and 15 of the Commission's Rules for Unlicensed Devices and Equipment Approval*, ET Docket No. 03-201 (Nov. 14, 2007).

[26] Comments of Cellnet Technology, Inc. and Hunt Technologies, LLC at 17, *In re Modification of Parts 2 and 15 of the Commission's Rules for Unlicensed Devices and Equipment Approval*, ET Docket No. 03-201 (Oct. 15, 2007).

The AMI plans filed by the utilities are the first attempt to extend the network to the consumer. If a deployment does not support all of the advanced functionalities expected in the future (e.g., distributed generation, plug-in hybrid electric vehicles (PHEV), energy storage), in a relative short period of time, the deployment could be perceived as a very expensive policy failure. If done correctly with high-speed communications, this investment could pay dividends for years to come as distribution automation, distributed energy resources and demand response become more prevalent in the distribution grid. Yet if this investment does not provide the capacity to support these communications intensive applications, this investment need to be repeated in the near future, significantly raising the overall cost. California ratepayers should not be required to fund such a wasteful approach.

To that end, utilities should be required to credibly demonstrate how their current deployment plans achieve not just a smart metering system, but also a Smart Grid. For example, to support distributed generation capable of supporting multiple customers (which is not supported by the SCE AMI system as noted earlier), any system must offer sufficient communications capacity to enable these distributed energy resources to be dispatched as needed within the overall electricity system. Dispatching a generation resource requires a number of questions to be answered in real-time, including:

- Is the generator ready? (Or in the case of PHEV, is it even there?)
- How much power can it provide? (For instance, for a solar generator, is it even providing power?)
- How long can it provide power? (For instance, the state of charge for a PHEV.)
- Once activated, can it continue to provide power?

- If it detects a problem and must disconnect, will it be able to reconnect? Did it disconnect due to a problem in the grid?

Answering these questions is critical to making these distributed resources part of the overall electricity market and require real-time interaction with the generator. This is impossible if the communications capacity installed by the utility requires tens of minutes for the flood of messages to move through the system. While such delays are perfectly acceptable for the meter information needed today, any utilities claims that these systems also provide the capacity needed for meeting renewable targets that come into force during the economic lifetime of these systems should be questioned. California regulators should push utilities for independent technical studies that demonstrate their effectiveness in this matter and receive binding assurances from utilities that ratepayer-funded investments such as these can support these needs.

Extending a utility's communication infrastructure throughout the grid and to the end customer presents a revolution in the utility's awareness of its overall systems. As such, this transformational capability is likely to provide opportunities for future capabilities unforeseen today. That is the core of the Smart Grid idea. This can not happen, however, if the infrastructure does not provide an open, interoperable platform which provides the bandwidth and sensing necessary as identified by EPRI, DOE and the Commission. California regulators should insist on independent technical studies showing these goals have been met and sufficient communications capacity is provided to meet the needs of the grid during the economic lifetime of these systems. To not do this is to greatly increase the chances that the ratepayer will be asked to fund new systems, at a much greater overall cost than if the investment had been made at the beginning.

As stated in the recent workshop, the proper investments are distinguished by their capabilities, not by a particular technology. In evaluating a utility's AMI deployment plan to see if it is the first step in a Smart Grid, key technical criteria must be considered. For the communications component, the utility should be required, at minimum, to demonstrate: (1) that the proposed system has enough capacity to support sensing, distribution applications of the type listed in the CEC Report and distributed generation widely deployed throughout its service area; and (2) it employs an open architecture that enables multiple technology providers to hook into the system.

The concept of future-proofing requirements closely comports with the Commission's observations in its *2007 IEPR*:

> With California's strong commitment to distributed renewable energy, combined heat and power, demand response, and reduced production of greenhouse gases, the design of these systems will have to change to accommodate the integration of these new resources. . . . Ideally, the 21st century distribution grid should allow grid operators to detect and respond to problems quickly by being able to manage the grid in real time. It should provide for rapid two-way information exchange between utilities and customers. It should allow the use of distributed resources to support grid operation. And it should allow for the seamless integration of the full spectrum of 21st century technologies. . . . As California utilities invest billions of dollars to expand and replace aging distribution infrastructure in the next five to ten years, it is critical to develop a framework to guide these investments. Without a transparent planning process, the state will not realize the full benefits of these resources.[27]

The Commission also noted:

> In spite of interest in automation and smart grid technologies, California utilities have very little regulatory incentive to design and build "smart" distribution infrastructure that can do more than assure that power is reliably delivered from distant central station power plants. Public policy should

[27] *2007 IEPR* at 195.

> encourage investment in technology that supports flexibility. Utility engineers are clearly interested in designing new infrastructure that will meet the needs of their customers in the future, but the current regulatory approval process is not designed to allow the transparent side-by side evaluation of new technologies and traditional investments. Without regulatory approval, utilities will be reluctant to introduce new technologies into their systems.[28]

In addition, the Commission observed that:

> Utilities spend approximately three-fourths of their total capital budgets on distribution assets, with about two-thirds spent on upgrades and new infrastructure in most years. These investments will be with us for 20-30 or more years. As utilities throughout the state plan to build new distribution assets and replace old assets, the magnitude of these investments suggests that we must understand what they are investing in and whether these investments will result in a distribution system that will serve customers in the future. Planning for investment in these assets should include requiring utilities, before undertaking investments in non-advanced grid technologies, to demonstrate that alternative investments in advanced grid technologies that will support grid flexibility have been considered, including from a standpoint of cost-effectiveness.[29]

Finally, the Commission concluded that:

> California continues, through legislation and regulation, to support its commitment to increased penetrations of renewable and highly efficient distributed generation, a trend likely to intensify as priority is placed on aggressively reducing greenhouse gas emissions. To assure maximum reliability and leverage benefits from these new distributed resources, the design of the electric distribution system must also evolve...It is clear that ADA adds significant value for California stakeholders by increasing service quality (reliability), improving resource efficiency (including reducing energy losses), and reducing the cost of distribution service. It is also important to specifically note ADA's contribution to increasing the penetration of distributed generation, including PV.[30]

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[28] *Id.* at 198.

[29] *Id.* at 199.

[30] *Id.* at 201, 203.

As noted in footnote 3, the AMI systems are not designed for distributed generation and thus do not achieve the Commission's objectives.

VI. CONCLUSION

CURRENT believes that the deployment of a Smart Grid is the best means to increase the efficiency of the transmission and distribution grid and enable consumers to manage their energy consumption with demand response programs and encourage the widespread use of distributed generation and renewables. In light of recent changes in federal policy, due in large part to concerns about the environmental impact of CO^2 and the desire for wide spread penetration of renewables, it is incumbent upon the state's policy makers to examine whether the AMI deployments currently being contemplated by utilities display the characteristics of a Smart Grid, are able to adapt to future utility distribution gird and consumer needs and policy demands, and are worthy of ratepayer investment. To the extent that an AMI deployment fails to display such characteristics, CURRENT recommends that policy makers scrutinize what the utility's future plans are to equip its system with additional functionality, and what the ratepayer will be asked to fund in the future.

Respectfully submitted this 9th day of May, 2008 at Sacramento, California.

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