The Smart Grid Collaborative Report

To The

Michigan Public Service Commission

December 2011

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Acknowledgements

The Michigan Public Service Commission (MPSC or Commission) would like to thank the participants of the Smart Grid Collaborative (Collaborative). This report is the product of several months of extensive research, study and discussions which resulted in the findings contained in this document.

The Collaborative consists of a Steering Committee and five workgroups. The Steering Committee included representatives from Indiana Michigan Power (I&M), Detroit Edison (DTE), Consumers Energy (CE), Michigan Electric Cooperative Association (MECA), Michigan Electric and Gas Association (MEGA), Michigan Municipal Electric Association (MMEA) and the MPSC. The workgroups included representatives from the utilities, Commission staff, Midwest Independent Transmission System Operator (MISO), International Transmission Company, LLC (ITC), American Transmission Company (ATC), Wolverine Power Supply Cooperative Inc. (WPSCI), Next Energy, Michigan Energy Options, and 5 Lakes Energy. Special thanks to Ms. Carone Dutz of Imperium Consulting Inc. who assisted the Steering Committee and workgroups with the entire collaborative process including scheduling and tracking deliverables.

Disclaimer

This report is a product of a collaborative process, which included stakeholders listed above. The report does not represent Commission-endorsed policy. The policy recommendations or goals related to smart grid outlined in this report do not commit the participating stakeholders to implementing or adopting such policies, in their business plans or in rate cases. The report is intended to serve as a document for the Commission to consider when addressing smart grid policy issues.

Executive Summary

In November 2010, the Commission established a Smart Grid Section within the Electric Reliability Division. In response to the initiation of smart grid pilot projects that could potentially lead to full deployment, the entrance of plug-in electric vehicles (PEVs) into the marketplace, and increased interest in smart grid national policy; the Commission directed the Smart Grid Section staff to actively lead a collaborative process - examining the challenges and solutions related to smart grid development and deployment in Michigan. The work on this report began in January 2011 with an intended goal to complete this phase in late 2011.

The Steering Committee initially established the following mission statement to focus the efforts of the Collaborative:

> The purpose of the MPSC Smart Grid Collaborative is to engage representatives from Commission staff, electricity transmission representatives and utility companies to develop a strategic plan to guide Smart Grid deployment. It is important to create a framework for increasing the predictability of recovering Smart Grid expenditures in rate cases and enhance the financial transparency of appropriate and reasonable investments made in electric Smart Grid infrastructure. Input from consumers, environmental groups, the business community and other stakeholders are welcome at the quarterly General Collaborative meetings as well as through staff contact.

The five workgroups of the Collaborative are:

Regulatory Policy Workgroup
Customer Programs and Communications Workgroup
Distribution and Grid Applications Workgroup
Generation and Transmission – Bulk Power Workgroup
Codes and Standards Workgroup

Each workgroup had two primary functions: 1) provide expertise during the investigation of multiple smart grid issues, and 2) provide data for the report. (For more detailed information about specific workgroup findings, refer to individual workgroup reports in Appendix A.)

Workgroups attempted to reach consensus on key issues. However, wherever consensus was not achieved, this was noted within the body of the report.

From the onset, the members of the Collaborative recognized that there would be several overlapping issues between the workgroups. In an effort to eliminate the potential for redundant work, an inventory of cross-cutting issues was compiled. A table of these issues is in Appendix C. The Collaborative also recognized that each workgroup might approach the same issues from different perspectives and with different objectives.

In addition to efforts undertaken within the five workgroups, the Collaborative process featured quarterly “General Forum” sessions which all parties interested in smart grid issues could attend. The General Forum sessions featured presentations from industry experts as well as updates from the workgroups.

While this reporting phase of the Collaborative made every attempt to cover major issues, certain issues were identified that will require further study within the Collaborative structure. One example of a major issue identified in this report was the lack of a state-wide vision. Without this vision, smart grid deployment has been driven by utility business strategies. Given the federal impetus for grid modernization and discussion within this Collaborative, further investigation is warranted to determine if this is an effective strategy.

The Collaborative recommends that the workgroups continue to refine and expand their initiatives. Under the continued leadership of the Steering Committee, the workgroups should meet on at least a quarterly basis with the goal of adding to their knowledge base and moving their recommendations forward. The key recommendations that should be continued are:

- Investigate the best approach to develop a smart grid vision; for each utility or a unified Michigan vision.
- Support continued participation in state and national organizations that are pursuing cyber security standards to protect customers, data and utility assets.
- Coordinate customer education and communications so that customers are aware of how the smart grid will impact them and how they can use it to their best advantage.
- Review MPSC rules and standards as they apply to various smart grid technologies to ensure that they are in sync with deployment and integration of those technologies.
- Refine cost allocation methodologies to provide a framework for utilities to utilize in developing a smart grid business case.
- Continue to monitor and incorporate evolving distribution and transmission technology and equipment, ensuring that Michigan’s electric grid remains reliable.

Preface/Background

Definition of Smart Grid

Acknowledging that the term "smart grid" can mean different things to different stakeholders, the Collaborative chose to adopt the U.S. Department of Energy's definition as its core:

> A smart grid is the electricity delivery system (from point of generation to point of consumption) integrated with communications and information technology for enhanced grid operations, customer services and environmental benefits.

Implicit in Michigan's idea of a smart grid are the following fundamental values and characteristics, as identified by the Steering Committee:

- Self-healing and resilient against physical attacks of all types
- Secure and resistant to cyber attacks
- Maintains and/or enhances electric reliability
- Optimizes grid efficiency in the face of increasingly complex issues such as PEVs, intermittent renewable generation, and human-caused or natural disasters
- Empowers consumers and open markets
- Enables increased safety and productivity of the electric utility workforce
- Supports demand reductions and environmental improvement
- Utilizes best fit, lowest cost solutions
- Incorporates a proven standards-based approach

Commission Orders in Case No. U-15278

The MPSC commenced the Collaborative on April 24, 2007, by its order in Case No. U-15278. This order directed MPSC staff to convene a statewide collaborative on smart grid infrastructure with the goal of improving the state's electric grid. The primary focus of the Collaborative was to review national smart grid infrastructure development, determine cost-effectiveness and practicality and establish evaluation criteria and standards, thus triggering pilot programs or broader deployment in Michigan. The Collaborative was instructed to focus on making the grid flexible and efficient, enabling distributed technologies, and preserving reliability.[1]

[1] Docket No. U-15278, Order Commencing Proceeding, April 24, 2007, http://efile.mpsc.state.mi.us/efile/docs/15278/0001.pdf

On March 11, 2008, the Commission expanded the directive of the Collaborative to include PEVs pilot projects, specifying additional objectives for the Collaborative to accomplish. In order to facilitate the potentially significant benefits of PEVs by achieving a high market penetration while also retaining the stability of the electric grid, the Collaborative was directed to address the integration of PEVs into the electricity grid.[2]

Collaborative Report

Introduction

The Collaborative recognized that smart grid is not just one technology or one application. It is a myriad of different options and equipment that must be considered together and separately. The stakeholders sought to break up the concept of "smart grid" into individual categories, and within these categories list individual applications and then discuss the benefits and challenges associated with them. Each category of applications has its roots in the present electric grid, with some applications having their origins many years ago.

Smart grid will not just be a method for remote meter reads, but will have an impact on all aspects of utility operation and planning. Smart grid-enabled resources such as time of use rates (TOU), direct load control (DLC), distributed generation, renewable resources and increased customer awareness impact not only the local distribution companies, but transmission operators and generation planning as well. Smart technology has been part of Michigan's bulk power system for decades. The collaboration and integration of all aspects of the smart grid with the business plans of the investor-owned utilities will allow for appropriate future growth. The future of smart grid is dependent on long-term planning strategies and integration of utility partnerships and resources.

Very little of the electric grid has changed in terms of capability and design since the original components were set in place. It has been said that if Thomas Edison were around today, he would recognize virtually all of the major equipment used in the electric distribution system. The grid was designed to economically and reliably deliver electrical power over long distances, allowing generation to be sited remotely from the load. During original grid build out, basic electromechanical grid protection equipment was installed to provide localized grid assessment, monitoring, and

[2] Docket No. U-15278, Order, March 11, 2008, http://efile.mpsc.state.mi.us/efile/docs/15278/0003.pdf

protection. This equipment had little ability to communicate with other remote protective equipment, which meant that grid equipment generally made decisions in isolation rather than with the benefit of real-time collective data from other contributing protective equipment. There was very little change in the design and daily operation of the grid throughout much of its history. The overall result was a highly functional and operable system that met the societal demands of the time and provided adequate service for decades.

Traditional electrical meters were developed in the late 1800s as a means to modernize the billing of electrical use. The first alternating current (AC) kilowatt-hour meter was developed in 1889. Meters used throughout the 20th century operate on the same principles and must be read manually on a monthly or yearly basis. In 1972, a sensor monitoring system that used digital transmission for meter reading for all utilities was developed and was the beginning of Automatic Meter Reading (AMR). Early AMR systems consisted of walk-by or drive-by readings of electric customers' meters, collecting meter readings electronically and matching them to the appropriate accounts.

Grid electronic controls and measuring devices have gradually replaced the electromechanical equipment by providing the same basic functionality, only with expanded capabilities. Improvements in telecommunications technology, such as fiber optics, radio frequency (RF) and cellular technologies have also driven the ability of grid equipment to communicate with other remote devices and with remote grid operators more efficiently and effectively. Grid automation, coupled with near real-time communication capability from any point on the grid, stands poised to improve and enhance the basic functionality of the grid where detailed and timely information can facilitate better service to customers, near real-time decision-making capability, integration of more diverse generation resources, more efficient use of energy, and an optimized grid.

Advanced Metering Infrastructure (AMI) represents networking technology that enables two-way communication between meters and a central system. These meters are referred to as "smart meters" because in addition to remotely collecting consumption data they can, in near real-time, report outages and power quality data. AMI can enhance how electric customers interact with the distribution system. Presently, customers have little interaction with the electric grid other than manually turning appliances, lights and other loads on and off, adding more loads to it, and receiving a monthly bill for the service. A smart grid has the potential to allow customers to be more economic in their energy consumption, own and utilize system resources, such as solar panels and PEVs, and receive more reliable service. All of these opportunities depend on the development and installation of various technology applications.

Utilities in Michigan are at various stages of deployment of smart grid and AMI. How utilities deploy smart grid is influenced by the priority they place on certain applications. This prioritization is influenced by a host of factors associated with a particular application, such as cost-effectiveness, customer acceptance, and market conditions of other associated technologies. There is a wide variety of opinions regarding which smart grid applications should be deployed first, second, and so on. Each application has costs and impacts as well as benefits, and many of these costs are difficult to quantify, as are certain benefits. The benefits and costs should be analyzed, including the "unquantifiable" benefits and costs. While some applications should be deployed together for cost-effectiveness, many applications can be deployed at different stages. It is clear that the deployment of smart grid as a whole will occur on a gradual, incremental basis as an evolution, not a revolution.

Regulatory Policy

Michigan's 1939 PA 3 gives the MPSC the power and jurisdiction to regulate all rates, fares, fees, charges, services, rules, conditions of service, and all other matters pertaining to the formation, operation, or direction of public utilities. This legislation requires an electric utility to formally request permission from the MPSC prior to adjusting its rates. Traditionally, this regulatory authority has been exercised through rate case proceedings in which MPSC staff and other parties investigate the decisional and operational prudence of utilities' actions in order to provide a record from which the Commission may determine its decision.

Due to the infancy of smart grid technology, there is minimal regulatory history regarding the topic. Guidance for early adopters of smart grid technologies in Michigan currently comes from federal legislation, state legislation, and Commission orders.

The Energy Independence and Security Act of 2007 (EISA), was signed into law on December 19, 2007. Title XIII addresses modernization of the nation's electric grid and gives the U.S. Department of Energy a leadership role in all areas of smart grid except two: interoperability (which is overseen by the National Institute of Standards and Technology and the Federal Energy Regulatory Commission), and state review of smart grid investment.

The MPSC has issued several orders since 2008 related to requests by utilities to recover costs associated with AMI programs. The orders discuss recovery of specific AMI initial capital and operations and maintenance (O&M) costs. One order discusses the policy and parameters associated with recovery of these investments.

The Commission established a set of initial smart grid cost recovery principles in its order in Case No. U-16191. These principles address cost recovery of smart grid expenditures related to both the pilot and full deployment stages of the utilities' programs. Collaborative stakeholders generally agreed that these principles were established to balance the interests of utilities and their customers, while continuing to encourage the development of smart grid in the state of Michigan. The Collaborative focused on key areas where clarification or modifications of the current non-accounting policies is needed. The Collaborative also discussed the need for new policies to be established in the early stages of deployment that would facilitate utility investment while adequately addressing the potential risks of smart grid implementation.

Collaborative stakeholders acknowledge that there is not a shared understanding of what constitutes the "pilot" phase of a utility's smart grid deployment versus the "full deployment" phase. This is an important difference to resolve because existing Commission policy guidelines would treat expenditures incurred in the "pilot" phase differently from those incurred in "full deployment." Without definitions that articulate the unique characteristics of smart grid "pilots" as well as "full deployment," the transition point from pilot to full deployment is ambiguous. There should be a shared understanding of the proper interpretation of the Commission's conditions for full deployment.

Each utility has a different project scope for full deployment that can be described by a deployment plan. This plan should be guided by a long-term vision for grid modernization. Deployment plans will provide all stakeholders with details of each utility's plan for grid modernization incorporating each utility's priorities and distribution system needs. To accomplish this goal, utilities should engage in forward planning that will enable a coordinated customer education and communication plan and establish a future vision to identify timing of regulatory policy needs.

The nature of smart grid investments and whether they are significantly different from other utility investments designed to improve or modernize their systems is an issue for review. One perspective is that there is a higher level of risk in smart grid investments because there is less certainty on how the technology will function over time and whether customer behavior will result in the expected benefits. Typically, utility investments have known benefits that occur upon installation. Without additional safe-guards that align the recovery of cost and the realization of benefits, a disproportional amount of project risk is borne by the customer. Another perspective is that smart grid investments align with other utility investments necessary to maintain the integrity and reliability of the grid. Consequently, these investments should be considered for recovery in the traditional manner. Commission policy should consider recovery of costs in rates that have appropriately treated the inherent risks to both the customer and the utility's shareholders.

The transition to a smart grid will require the early retirement of legacy equipment such as electromechanical meters prior to the end of their useful life. As utilities seek recovery of the costs of legacy equipment resulting from smart grid deployment, it is important that the regulatory treatment of these stranded investments is defined. Cost recovery treatment of these costs should consider all perspectives in order to balance the interests of both utility and customer. Stakeholder non-consensus regarding the differences between traditional investments and smart grid investments led to the exploration of non-traditional cost recovery methods (i.e., riders, surcharges) for smart grid purposes. The Collaborative examined the benefits and shortcomings of non-traditional cost recovery mechanisms used in other jurisdictions for potential application in Michigan. The Collaborative could find no justification for using non-traditional recovery methods. There was stakeholder consensus that the appropriate methods for addressing the potential risks of smart grid deployment exist in the traditional process.

The Collaborative initially acknowledged that the allocation of smart grid costs among customer classes should follow the tenets of traditional cost of service. Specifically, as has been the traditional practice among Michigan's utilities, the cost of providing service is allocated among customer classes based on the "cost causation" principle, whereby rates reflect, to the extent possible, the costs actually caused by the customer class from whom the utility seeks recovery. Upon further discussion, some stakeholders were concerned with the application of the existing historical methodology because it is expected that all customers, to some extent, will benefit by the deployment of smart grid, not just those customers for whom the specific investments are made. An alternative approach that allocates costs proportional to the benefits received seems plausible; however, there is potential difficulty in quantifying achieved benefits and assigning them to the appropriate rate class. Thus, stakeholders agreed that this issue requires further detailed discussion so that a consistent methodology that fairly allocates the costs of smart grid is established.

Costs and Benefits

As with any new technological venture there must be assessment and reflection to ensure smart grid benefits are being effectively utilized. The investment in digital technologies requires measurement and a clear understanding of available benefits. This will engage stakeholders, protect customers and allow advanced uses of a modernized electrical grid. To protect customers, clear metrics need to be developed and used to verify effective smart grid deployment without adding a significant burden on utilities.

A cost benefit framework offers a mutually recognized methodology for presenting the costs and benefits associated with smart grid investments. The objective of the cost benefit framework is to provide consistent economic comparisons of smart grid investments. Developing a framework in lieu of a standardized model allows utilities to maintain some flexibility while providing guidance of acceptable attributes for regulatory purposes.

As part of a defined cost benefit framework, certain common cost benefit model principles are recommended for smart grid business case analysis. A model should be self-contained within Microsoft Excel and contain specific attributes and structure to facilitate review and analysis. Any model should clearly define and support all assumptions and inputs made in the estimation of included costs and benefits; model inputs should be identifiable and traceable. Cost benefit modeling should convert future expected cost and benefit revenue streams into a net present value using appropriate discount rates and allow for inclusion of sensitivity analysis.

The costs associated with smart grid development are primarily accrued in the early stages of deployment and therefore easier to quantify. These costs are specific to the smart grid investments and necessary for full benefit realization throughout the project lifecycle. A smart grid benefit connotes a positive change resulting from a smart grid function implementation.

Smart grid benefits should be categorized into three specific categories based upon the entity that realizes the benefits: customer, utility and society/other. Smart grid benefits have the potential to vary greatly from utility to utility based on technology selection as well as customer demographics.

Recognizing these variations allows utilities to develop proprietary estimation methodologies based on their deployment plans. These methodologies should accompany the benefit estimations for regulatory purposes. The utility needs to quantify and monetize the individual types of benefits. Due to the complex scope and multi-phase nature of smart grid, issues may arise around benefits and costs that cannot be easily quantified and monetized.

Stakeholders are challenged with continual assessment of smart grid deployment benefits and costs. This process is essential in understanding the long-term impact of grid modernization. Stakeholders should periodically evaluate if the projected benefits associated with an approved smart grid investment are being realized for customers, the utility, society, and/or other stakeholders.

(For further information about this topic, reference the Regulatory Policy Workgroup Report in Appendix A.)

Customer Education

Smart grid deployment will have a direct impact upon the relationship between utilities and their customers. AMI is the most visible component of smart grid, allowing for two-way communication. The combination of advanced meters and associated applications has the potential to allow customers to choose how and when they use energy. Successful smart grid implementation is grounded in customer understanding and acceptance of its benefits. Education and communication of relevant information is critical to moving these goals forward.

Historically, utilities have needed to inform customers about new customer programs or changes in service. In general though, customer behavior changes were not necessary. In contrast, smart grid assumes the customer will become a participant in energy management.

In 2009, all Michigan utilities launched their first significant energy efficiency program portfolios in more than a decade. The purpose of these programs was to provide products, services, and information for both residential and business customers to help them take greater control of their energy use and reduce costs. Utility benchmarking research and focus groups concluded that customers are motivated to take advantage of energy efficiency programs by the possibility of saving money on their energy bills and improving the environment.

It is essential to understand that customers have unique characteristics. Not all customers are the same and when communicating with customers, all stakeholders should keep this in the forefront. Examples of characteristics to recognize are: early or late adopters, energy savers, do it yourselfers, and environmentally conscious. Awareness and utilization of key customer characteristics will make smart grid communications more effective.

Michigan is a demographically diverse state and customers represent a wide spectrum of social and economic sectors. Utilities can create messages based upon customer interest through segmenting the service population. Segmentation allows the utilities to target messages that speak directly to the interests of the customer and cross-cut traditional boundaries. For example, residential and commercial customer messages that incentivize owners, renters, technology enthusiasts, thrifty buyers, and environmental conservationists will motivate behavior change. Benefits defined by the interests of the segment will encourage customer engagement.

The Customer Programs and Communications Workgroup looked nationally to lessons learned from smart grid pilots and deployments. The effort provided information regarding the best methods to effectively educate customers. Smart grid programs at Central Maine Power, Oncor, Pacific Gas and Electric Company, Salt River Project, OGE Energy Corporation, and others were reviewed. An effective communication strategy should be transparent, and contain accessible information using multiple communication avenues that provide customer-focused and timely information. An appropriate amount of funding will be necessary to providing effective education programs. Education programs are critical for both customers and employees so they can understand changes which lead to informed decisions.

Customer Protection/AMI

Utilities will need to select and install smart meters that enable smart grid programs and provide reliability benefits for customers. Furthermore, utilities should select and install meters that are both compliant with national standards and provide automated features that contain full operational data security. Full disclosure of information from credible sources needs to be made available to utility customers related to meter education, i.e., data security and safety awareness, including, but not limited to RF concerns. Utilities should select meters using internal component designs that detect outside intrusions, enable isolation of affected equipment and feature automated key exchange and secure firewalls.

Customer protection issues must be addressed with customers before and after the deployment of smart grid hardware and infrastructure. Protection of customer usage data includes the issues of customer confidentiality, data privacy, and allowing third party access. In the future, with the collection of detailed data through AMI, current utility practices of data privacy should continue to be followed. As with retail open access today, customer usage data will be considered private and utilities will not release customer specific data to third parties without signed authorization from the customer. Stakeholders agree that the customers should maintain their rights to their data and that the utility should remain responsible for the collection, maintenance and security of customer data.

Customers need to fully understand what smart meters provide: their functions and uses, and that customers' data will continue to be held securely and confidentiality. Policies regarding use of customer data will need to be developed if customers authorize sharing their usage data beyond operational use by utilities. Efforts by the North American Energy Service Board (NAESB) and the National Association of Regulatory Utility Commissioners (NARUC) will provide reference points for developing best practice guides for data access and privacy.

Utilities will need to utilize customer usage data to achieve the customer and operational benefits from the smart grid investments. In addition, utilities require usage data and other information from smart meters to efficiently operate, maintain, and secure the electric distribution system. There are many potential applications for customer data utilization, including: rate options for customers based on their usage levels and patterns, identification of malfunctioning customer equipment and detection of highly loaded utility equipment, etc. There is a need for clarity regarding the role of smart meters and applications that are enabled by the presence of a smart meter.

In 2008, a set of principles for smart meter capabilities was developed through the combined effort of staff and utility representatives. Those principles are still applicable today. Smart meters should be capable of supporting various price responsive tariffs; collecting energy usage data at a level that supports customer understanding of hourly usage patterns and the relation to energy costs; allowing access to personal energy usage data such that customer access frequency does not result in additional AMI system hardware costs; interfacing with load control communication technology; and allowing customer flexibility in payment options. They should also be compatible with applications that provide customer education and energy management information, customized billing and complaint resolution and utility system applications that promote and enhance operating efficiency and improve service reliability.

The effect of smart meter enabled remote connect and disconnect functionality should be addressed with AMI deployment. The ability to remotely connect and disconnect customers does not void certain customer protections already established in billing rules such as those for residential customers during the heating season and critical care customers. Procedures contained within current billing rules should be revisited to determine the need for potential changes in customer notification, guidelines for customers to avoid disconnection, procedures for power restoration, and fees for connect/disconnect services.

A prepayment program allows customers the option to purchase a specified amount of electricity in advance of its use. The program could allow for automatic disconnection of service when the amount of electricity usage exceeds the amount purchased. Prepayment can provide an alternative to deposit requirements for utility service and may reduce the utility's credit and collections costs. Prepayment may also help a customer reduce their consumption of electricity. At a minimum, operation of a prepayment program would need to provide: 1) 24/7 customer access to their actual electricity usage and remaining credit, 2) a way for the customer to purchase credits, and 3) a connection between the customer and utility to signal when credit is depleted and restored. The costs associated with a prepayment program may be high relative to savings realized by the operating utility.

The Collaborative found RF to be both a scientific and emotional issue. As defined by the Federal Communications Commission (FCC), radio waves and microwaves emitted by transmitting antennas are collectively referred to as RF energy. The FCC has established Maximum Permissible Exposure (MPE) limits for smart meters assuring that they transmit at levels that are safe. Numerous reports exist that indicate smart meters have very low RF emissions and support the overall safety of smart meters. Many of these reports are cited on the MPSC website as well as in the November 2011 Federal Energy Regulatory Commission's (FERC) "Assessment of Demand Response and Advanced Metering."[3] The FERC report found that "The radio frequency (RF) emissions associated with advanced metering have not been proven to present a risk to human health, but concerns about a possible linkage continue."

[3] http://www.ferc.gov/legal/staff-reports/11-07-11-demand-response.pdf

The Collaborative recognized there are continuing customer concerns regarding RF and reviewed a multitude of hearings, regulatory and judicial reviews and policy directives at the federal and state level. Despite the findings of RF studies and the MPE levels set by the FCC, some customers are still convinced that smart meters cause health problems. The Collaborative suggests that utilities formulate future deployment strategies to address customer concerns. Customer education can be an effective method to alleviate customer apprehensions about the safety of smart meters. The Collaborative recommends that utilities and the MPSC continue to explore this issue as additional scientific research becomes available.

Coordination between AMI capability and the billing rules and technical standards should be maintained. A timeline should also be developed regarding deployment of AMI meters, and availability of dynamic pricing. A waiver of the current meter testing rules may be appropriate considering that smart meters are already pre-tested for accuracy and meter testing is costly.

(For further information about this topic, reference the Regulatory Policy Workgroup Report in Appendix A.)

Meter Opt-Out Provision

Some states have responded to customer RF concerns by establishing a meter opt-out provision. Meter opt-out allows the customer to choose not to have a smart meter installed and retain either the existing electromechanical or digital meter which requires manual reading. Other options include turning the radio transmitter off or moving the meter. These options create additional costs to both customers and utilities to process meter data from redundant systems, and also results in lost benefits to customers and utilities. The lack of a smart meter at a customer premise prohibits a utility from providing better tangible services, such as improved billing accuracy, more rapid identification and response to power outages without customer action, and potential services such as enhanced customer billing and rate options. Customers without smart meters will not be able to take advantage of these options and will likely experience different costs and quality of service than customers with smart meters. On the other hand, the Collaborative recommends that each utility should review the existing opt-out policies and consider its opt-out policy direction.

Distribution and Grid Applications

Many aspects of smart grid will affect the distribution system. The major categories of distribution and grid applications are AMI, customer programs, demand response, distribution automation, and distributed resources.

Demand response has been practiced to some degree by most electric utility service providers since the 1980s. Originally rooted in least-cost planning ideas developed in the 1970s, demand response came into general use with demand-side management constructs. Most electric utilities now use demand response primarily as an emergency measure to improve grid reliability. But with the expansion of the smart grid, demand response could also be used to reduce peak demand and lower costs.

Improvements in telecommunications technology and protective distribution equipment have contributed to the evolution of distribution automation. For example, grid assets will soon be able to communicate in near real time with one another and with grid operators. This allows utilities to determine the presence and location of system outages digitally which will result in quicker and more efficient response times.

Distributed resources in the context of smart grid refer to renewable energy and electricity storage elements such as batteries. Renewable energy is defined as energy from sources such as biomass, biofuel, solar, wind, hydroelectric, tides, and geothermal heat, which are naturally replenished. The smart grid has the potential to improve the economics of renewable energy sources particularly solar and wind power.

Projecting the future of any technology is difficult, and the smart grid is no different. All stakeholders provided a list ranking various smart grid applications for future deployment; the ranking is contained in Appendix H. However, these are only projections. Any number of unforeseen factors could cause a change in ranking and the rationale behind it. In like manner, attempting to articulate a set of long-term recommendations for smart grid deployment in Michigan is equally daunting due to a high level of uncertainty.

Michigan utilities should achieve certain performance targets, selecting targets that are smart grid-specific and within a reasonable timeframe. Examples of such targets could include: automatically isolate main line faults and restore unaffected main line portions of the circuit for all main line faults on circuits that have electrical ties to other circuits; reduce greenhouse gas emissions through voltage optimization and distributed resource integration by a specific year; and improve Michigan utilities' generation and distribution efficiency by a percentage to be defined by the stakeholders through voltage optimization and demand response.

All smart grid applications, to the extent they are found cost-effective within the prescribed regulatory framework but respective to each utility, should be enabled by Michigan utilities deploying smart grid.

Generation and Transmission

The future of the smart grid is dependent upon the integration of all utility partnerships and resources along with long-term planning strategies. Since 2005, the utilities' generating units have been effectively dispatched by MISO under federal supervision. The strategies for determining economic dispatch parameters have remained unchanged and the manner in which MISO dispatches generators is much the same as the manner in which the utilities dispatched their generating units for the 30 years preceding MISO. Over 1,200 generators make offers to operate in the day-ahead energy and ancillary services markets for every hour of the year. Additionally, those same generators are physically dispatched by MISO and provide bids and offers to increase or reduce their production in the real-time energy and ancillary services markets for every five minute period of the year.

Since the launch of the ancillary services market in January 2009, MISO has evolved the markets to allow demand response to participate in the energy and ancillary services markets on a comparable basis to generation. A regulation product for storage was also implemented that provided grid level storage facilities, a product specialized for their operating characteristics. Stakeholder discussions are currently underway to address the impact of dynamic retail rates on load curves, particularly load peaks.

The members of the Generation and Transmission- Bulk Power Workgroup believe the realization of smart grid's promise depends upon long-term planning strategies with the integration of all utility partnerships and resources in this process. Transmission operators should continue to cooperate with MISO and the North American Synchrophasor Initiative (NASPI) on their synchrophasor implementation project to provide data and to help develop applications that use the data.

Transmission operators should continue to improve reliability by installing new advanced transmission system protection systems and advanced intelligent electronic devices.

Michigan companies have deployed a fair amount of smart grid resources with more planned for the future. As these technologies gain acceptance, they should be evaluated to assess the impacts on generation and transmission in the state. Future discussion and cooperation is needed for the optimum smart grid deployment on the transmission side of the industry in Michigan.

Network Communications

All of the smart grid technologies demand an appropriate communication network in order to have a 2-way dialogue between the equipment/customer and the utility. There is no one communications technology that is best for all grid communications. It depends on the needs and the specific circumstances of the utility. The goal should be to build a communications network architecture that is integrated, flexible, secure, and built, to the extent possible, to recognize standards. Options include private RF mesh solutions that connect meters via a concentrator; point-to-point (under glass) communications with individual meters using public cellular networks (which also provide the backhaul for mesh networks); power line communications (PLC); Wi-Fi; and several others. All of these decisions need to be based on specific utility application requirements, topologies, and existing installed infrastructure. There is no one-size-fits all.

Michigan utilities should continue moving toward completion of distribution system communication channels, emphasizing functions that provide accurate system-wide information, increased grid stability and improved restoration abilities: AMI, supervisory control and data acquisition (SCADA), and distribution automation should be integrated to improve information availability.

While not an initial deployment issue, network sharing is an issue for consideration and action. Avoidance of dual networks in the same geographic areas when operationally and financially viable should be a long-term smart grid planning goal for Michigan. Network sharing will result in reduced costs and increased program efficiencies. Utilities have discussed this for several years and several operational and financial issues need to be overcome to make this a reality. Policy actions at the federal level should also continue to be monitored.

There will be billing between utilities for meter-related services, due to the number of gas and electric meters in overlapping areas for each utility. There may be justification for some standalone networks as is the case in California. Southern California Gas was able to provide justification for a standalone gas meter communication network in both San Diego Gas & Electric and Southern California Electric areas due to the complexities of sharing meters. (For further information about this topic, reference the Distribution and Grid Applications Workgroup Report in Appendix A.)

Codes and Standards

An often overlooked trait of our modern electrical grid is the commonality of all of the components. Across the United States, the hardware and software devices are built upon a backbone of standards that allow the consumer to move anywhere in the country or state and seamlessly plug-in their electrical devices. The future vision of the modernized grid includes secure and seamless connectivity for devices capable of communicating within the grid.

As the electrical grid is updated into the smart grid, it is important that we achieve a grid that is interoperable. A grid that is built upon nationally-accepted codes and standards will allow better economies of scale, increased security, and promote best practices. Michigan smart grid stakeholders should continue to participate and provide input to influence national efforts designed to promote adoption of smart grid interoperability standards. Stakeholders should also proactively influence the national and state direction and adoption of smart grid consumer privacy-enabling technology standards and cyber security.

Support for development of the smart grid in the United States gained impetus from Title XIII of EISA. The development of the smart grid was identified by EISA as a national policy goal. Incentive for standards development increased as the American Recovery and Reinvestment Act (ARRA) of 2009 provided the United State Department of Energy (US DOE) with $4.5 billion to invest in smart grid technology and demonstration grants. The ARRA funds greatly accelerated the development and implementation of smart grid technologies and interoperability standards.

EISA assigned the National Institute of Standards and Technology (NIST) the task of coordinating the development of a framework of information management protocols and standards that will achieve smart grid device and systems interoperability. NIST responded to its EISA mandate by developing and implementing a plan to identify an initial set of standards, to establish a framework to sustain the development of additional standards that will be needed, and to set up an infrastructure for conformity testing and certification. The NIST plan incorporated three phases.

The first phase of NIST's plan included holding public workshops in April, May and August of 2009 and culminated in the release of the framework document in January 2010. This phase of NIST's plan also established the first 16 Priority Action Plans (PAP) for those areas identified as needing further standards development. The second phase of the NIST plan, initiated in November 2009, was the creation of the Smart Grid Interoperability Panel (SGIP). There are nearly 700 member organizations in the SGIP. They are divided among 22 stakeholder categories. The third phase of the NIST plan is to provide a framework for conformity testing and certification of smart grid devices and systems. This phase of the plan is currently being led by the SGIP's Smart Grid Testing and Conformity Committee.

The public utilities within the state of Michigan have been actively involved in the smart grid interoperability standards effort since 2009. They are all active members of SGIP and provide direct input and leadership into many of the standards development efforts. As an example, all the Michigan utilities are active members of several OpenSG groups and the OpenSG Technical Committee. OpenSG is a technical consortium group that has been very instrumental in the definition of use cases and requirements for future interoperability standards.

Cyber security and data privacy continue to be an area of priority for interoperability standards development. Security of the bulk power system is a primary concern at the national level. FERC has enacted rulemaking to ensure compliance with reliability and cyber security standards through such actions as the NIST-established Cyber Security Coordination Task Group (CSCTG). The CSCTG has more than 200 volunteer members from the public and private sectors, academia, regulatory organizations and federal agencies. Cyber security is also being addressed in a complementary and integral process that will result in a comprehensive set of cyber security requirements through the North American Energy Reliability Corp's development of Critical Infrastructure Protection (NERC-CIP) standards.

With a clear emphasis on security, these standards have defined the operation, reporting, and maintenance of critical cyber assets very precisely. As electric distribution systems become more automated and interconnected, the risk of a large aggregated load impact becomes greater. The ongoing evolution of interoperability standards will help stakeholders avoid vendor lock-in, enable technology innovation, lower the risk of premature technological obsolescence and reduce cost by supporting a global market for smart grid technologies. Due to the large number of standards-setting organizations and the overlap of activity within the smart grid industry, strategically focusing Michigan's participation will provide the greatest benefit. The Codes and Standards Workgroup intends to continue to provide a forum for evaluating and focusing Michigan's involvement in the national standards development work.

Smart grid stakeholders should establish a repository of references for codes and standards and continue to actively participate and/or monitor the SGIP, OpenSG, NIST, and other significant standard development organizations such as Institute of Electric and Electronics Engineers (IEEE), American National Standards Institute (ANSI), Zigbee and NAESB. This would include establishing positions on critical codes and standards issues that represent the stakeholders. Michigan utilities should remain in compliance with industry best practices and standards as identified for smart grid interoperability and evaluate the codes and standards and technology required for the interoperability of communication and distribution system networks.

Reporting

As utilities implement smart grid applications, the Commission will need to track utilities progress and success of the various smart grid technologies installed. The Collaborative identified the need for clear and concise reviews and reporting requirements in order to provide progress updates inclusive of insight into the customer value proposition of installed smart grid applications. While acknowledging these general regulatory reporting needs, the Collaborative was unable to come to a consensus on specific smart grid investment reporting requirements. Visions of acceptable smart grid reporting requirements ranged from embedded smart grid reporting updates in general rate case filings to requiring utilities to file annual smart grid reports inclusive of tracking multiple program metrics. The stakeholders suggest that the Commission adopt a consistent reporting requirements policy regarding smart grid programs that is not overly prescriptive but does provide adequate data.

Summary of Smart Grid Collaborative Recommendations

The Collaborative determined that the best approach to addressing all of the issues related to smart grid was to divide the larger group of participants into workgroups and even subgroups. The workgroups and subgroups used their expertise to review numerous smart grid resources and provided a wealth of data for their reports. In order to stay true to the workgroups' efforts, the recommendations contained in this report are those that were determined by the workgroups and supported by the Steering Committee.

One of the overlying recommendations was to have a smart grid vision for Michigan. Many of the other recommendations would be resolved through a smart grid vision. The vision could be a single statewide vision or it could be a framework that would be utilized by the various stakeholders throughout Michigan. A smart grid vision could incorporate many of the recommendations that were presented by the workgroups. Some of the workgroups' major proposals would be encompassed under a smart grid vision such as having clear methodologies for determining costs and benefits; sending a concise and instructive message to customers; invoking standards that are consistent and appropriate; protecting customer data and the security of the grid; and continuing Michigan's strong and reliable infrastructure. The workgroups' recommendations are contained within each workgroup's report in Appendix A. The recommendations can also be found in Appendix K.

The Steering Committee and the Commission staff wish to thank the Collaborative participants for their hard work and dedication over the many months it took to write this report. The Michigan smart grid initiative is still in its early stages and this is just a first step on the path to a better, smarter, stronger and more user-friendly grid in Michigan.

APPENDIX A

Collaborative Workgroup Reports

APPENDIX A

Table of Contents

Regulatory Policy Workgroup Report

Purpose and Focus

In order to promote an economically viable smart grid in a regulated market, it is important to have the proper policies guiding smart grid implementation. Currently Michigan's regulated utilities are in the process of piloting multiple smart grid technologies in order to quantify benefits and develop a business case for deployment. To ensure that adequate attention was provided to all aspects of smart grid deployment, the workgroup was divided into four subgroups: 1) deployment, 2) cost benefit framework, 3) cost recovery, and 4) customer protection.

- Deployment- Identified the categories of existing and potential policies (commission orders, administrative rules, federal legislation, state legislation, tariffs, and national standards). Additionally, the Deployment subgroup explored the issues related to existing and potential policies, and what the next steps are relating to potential future policies.
- Cost Benefit Framework- Developed a consensus framework for the classification of smart grid costs and benefits. This framework could be used as a guideline for utility business cases when addressing smart grid investments.
- Cost Recovery- Identified current cost recovery issues and proposed Michigan policies to address cost recovery of smart grid pilot and full deployment programs. Proposed cost recovery policies address: 1) defining cost to be recovered, 2) recovery mechanisms, and 3) cost assignment.
- Customer Protection- Reviewed current customer protection topics and addressed the need, if any, for customer protection measures in the areas of: metering, data, interoperability, rates, customer privacy, measurement, assessment and reporting, and billing.

Policy issues have been explored within the subgroups. Suggested courses of action are identified within the recommendations sections of the report.

Historical Perspective

Public Service Commission Authority

Michigan's 1939 PA3 gives the MPSC the power and jurisdiction to regulate all rates, fares, fees, charges, services, rules, conditions of service, and all other matters pertaining to the formation, operation, or direction of public utilities. This legislation requires an electric utility to formally request permission from the MPSC prior to adjusting its rates. Traditionally, this regulatory authority has been exercised through rate case proceedings in which MPSC staff and other parties investigate the decisional and operational prudence of utilities' actions in order to provide a record from which the Commission may determine its decision.

Due to the infancy of smart grid technology, there is minimal regulatory history regarding the topic. Guidance for early adopters of smart grid technologies in Michigan currently comes from federal legislation, state legislation, and Commission orders outlined below:

Federal Legislation

The federal Energy Independence and Security Act of 2007[4] (EISA), was signed into law on December 19, 2007. Title XIII, sections 1301 through 1309[5] of this act address modernization of the nation's electric grid and contain provisions giving the U.S. DOE a leadership role in all areas of smart grid except two: interoperability (NIST and FERC), and state review of smart grid investment. Section 1301 includes 10 characteristics of a smart grid:

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

[4] Energy Independence and Security Act of 2007, http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=110_cong_bills&docid=f:h6enr.txt.pdf
[5] For a complete description of each section within EISA, please see the act (link above).

(9) Development of standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid.

(10) Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services.

Commission Orders

The MPSC has issued several orders since 2008 related to requests by utilities to recovery costs associated with AMI programs. The orders discuss recovery of specific AMI initial capital and O&M costs. One order discusses the policy and parameters associated with recovery of these investments. The Collaborative reviewed these orders, and evaluated the current MPSC policies and made recommendations for policy changes to better serve all smart grid stakeholders. The following is a brief summary of the MPSC orders through the date of this report.

The Detroit Edison Company

The Commission has issued two orders in recent DTE rate cases related to its initial investments in AMI. In its December 23, 2008 order in Case No. U-15244, the Commission stated that "Detroit Edison may recover the expenses associated with the pilot of the AMI project, as well as the infrastructure costs included in net plant from that pilot. The Commission favorably views the company's investment in a more technologically advanced infrastructure and is pleased to learn of the progress made in this area." (Opinion and Order, p 62-63)

In 2009, DTE requested, in Case No. U-15768, recovery of additional AMI expenditures associated with its pilot program consistent with the Commission's previous rate case order in U-15244. In its January 11, 2010 order, the Commission approved additional costs associated with DTE's continuing AMI pilot program; however, the order also included additional requirements for the utility to follow in a subsequent general rate case filing:

> The Commission approves the inclusion of expenses related to AMI as well as the inclusion of the capital expenditures in rate base discussed briefly in a previous section.
>
> In its next rate proceeding, Detroit Edison should file a detailed benefit cost analysis and a report on the progress it has made with AMI, the probable benefits to ratepayers, and

> the plan it has to ensure those benefits reach ratepayers. At that time, there should be more experience with the system, which may provide the Commission sufficient evidence to support a finding concerning whether the system is used and useful and reasonable and prudent, which is required before full recovery can be authorized. (Opinion and Order, p 55)

On October 29, 2010, DTE, in Case No. U-16472, asked to recover net costs associated with installing up to 600,000 meters in its AMI program, along with net costs for initial investments associated with its Smart Home and Smart Circuit programs. In addition, DTE included in its filing, consistent with its previous rate case order, a report on the progress made with AMI resulting from the pilot programs (including both successes and challenges) and provided a detailed utility cost benefit analysis.

The Commission issued an order on October 20, 2011 in Case No. U-16472 approving DTE's historical and projected capital expenditures related to its AMI, Smart Home and Smart Circuit programs. The Commission did however, disallow a $3.4 million contingency since it was unclear how these funds would be spent and agreed that expenditures should be capped at the level of projected lifecycle benefits as a means of cost control and to assure that the benefits of AMI to customers are maximized. In its order, the Commission also stated its support for smart grid programs:

> [T]he Commission views Smart Grid as a whole (considering AMI a part of that whole) as a potentially transformational technology that will accommodate the incorporation of renewable and distributed generation to replace the current fossil-intensive generation system, provide customers with new and easier methods to manage their energy usage and bills, and provide greater reliability and power quality, along with a host of other possible benefits. (Order, p 23)

The Commission also required DTE to update its cost/benefit analysis in its next rate case and provide additional reporting on its progress at that time.

Indiana Michigan Power Company

The Commission has not issued any orders related to AMI or smart grid investments. I&M's 2010 rate case (Case No. U-16180) resulted in a settlement. Thus, no specific AMI or smart grid investments were referenced in the order approving the settlement. In the settlement in Case No. U-16180, I&M agreed "not to implement the Generation Investment Tracker, the gridSMART Tracker, and the Enhanced Distribution Reliability Tracker or any other rates, surcharges, tariffs or rate mechanisms that it requested in its application or testimony in this case...." (Opinion and Order, Attachment 1, p 5)

Consumers Energy Company

The Commission has issued two orders in recent CE electric rate cases related to its investments in smart grid technologies. In electric rate case No. U-15645 filed in November 2008, CE introduced plans for its AMI program, including a pilot of direct load control and demand response. CE sought approval of capital expenditures related to the AMI program for the years 2007 through 2009. In the Commission's final order dated November 2, 2009, the Commission approved all of CE's requested expenditures:

> The Commission finds that Consumers shall receive its full year proposed 2009 AMI expenses. The Commission rejects the proposal to refund any portion of these funds, whether or not the ARRA grant or any other available grant funding is received. This project is essential to the future of Michigan, and the Commission expects Consumers to expend all the available monies on AMI infrastructure. (Order, p 59)

On January 22, 2010, CE filed in Case No. U-16191 requesting recovery of the costs related to piloting and testing of smart meters, as well as the assessment, development and evaluation of information systems and field equipment. The case included a request for recovery of capital expenditures for the smart grid program for 2010 and the first six months of 2011. The MPSC staff proposed a reduction in CE requested capital expenditures. Due to delay in its planned deployment, CE agreed with staff's proposed reductions. In its final order in the case on November 4, 2010, the Commission acknowledged that it was reasonable for CE to continue with its AMI/smart grid pilot activities, but did not approve full deployment of the technology. The Commission also adopted the 11 policy guidelines proposed by staff.

The following 11 points were adopted in the Commission Order in U-16191 regarding cost recovery of smart grid expenditures:

1. Piloting phase expenditures are classified into two categories: a) those directly related to the piloting function, e.g. testing, and b) those actually related to the full deployment.
2. Direct pilot expenditures are deemed recoverable expenses irrespective of whether or not the pilot indicates a go-forward decision.
3. A cost/benefit analysis is not required as a precondition for cost recovery of direct pilot expenses. However, the utility must demonstrate that the costs were reasonably required to fulfill the objectives of the pilot.
4. Because the financial risk associated with the Smart Grid pilot is borne by ratepayers, it is incumbent upon the utility to keep pilot costs as low as reasonably possible.
5. Prior to the completion of the pilot, capitalized expenditures will be included in utility rate base as Construction Work in Progress (CWIP) with an Allowance for Funds Used during Construction (AFUDC) offset. Capitalized expenditures directly related to the pilot will not be reflected in rates until the pilot phase is concluded.
6. Smart Grid capitalized expenditures directly related to full deployment, but incurred during the pilot phase of the project are subject to the “used and useful” ratemaking principle. Thus, if full deployment is not approved by the Commission, full deployment costs incurred during the pilot phase of the project are not recoverable from ratepayers.
7. Commission approval of full deployment means that the Commission supports a utility's decision to move the project out of the pilot/testing phase into final deployment.
8. Commission approval of Smart Grid full deployment means that the Commission will not re-evaluate the utility's initial decision to move forward with a system-wide infrastructure deployment midway through the full deployment phase.
9. Commission approval of full-deployment does not guarantee cost recovery of future expenditures. CE will remain responsible to support individual expenditures for reasonableness and prudence. Such regulatory policy protects customers from having to bear the cost of unreasonable cost overruns, unnecessary expenditures, project “gold plating” or imprudent project decisions.

10. The project risk is borne by stockholders. Thus, subsequent to the full deployment phase, i.e. during the project lifecycle, and to the extent that the utility is not able to achieve benefits equal to or greater than lifecycle costs, then to such extent, full deployment expenditures are not "used and useful" and thus not recoverable from ratepayers.

11. Commission approval of Smart Grid cost recovery of full deployment must be pre-conditioned upon: a) CE achieving all major pilot milestones; b) demonstration that a full business case, (i.e. detailed lifecycle cost/benefit analysis) supports full deployment; and c) the filing of a comprehensive plan for specific customer programs that ensure that customers can obtain savings to offset the cost of Smart Grid infrastructure for which recovery is being requested. (Order, p 16-17)

CE also sought recovery for its gas AMI program beginning with gas rate case No. U-15986 filed in May 2009. CE requested recovery of capital expenditures for 2009 and the nine months ending September 2010. In its final order issued May 17, 2010, the Commission authorized CE to recover approximately one-half of its requested expenditures. The Commission also required CE to submit a full business case in its next rate case filing. In its subsequent gas rate case, No. U-16418 filed in August 2010, CE requested recovery of gas AMI capital expenditures for the years 2010 and 2011. The parties to this case entered into a settlement agreement which the Commission approved on May 26, 2011. On August 11, 2011 the Commission issued its final order in this case in which it agreed with the Attorney General's position that CE failed to make a convincing business case for the implementation of gas AMI. In response to the Commission's concerns, CE has reflected the removal of all gas-related AMI costs in its most recent gas rate case filing, No. U-16855 filed on September 2, 2011.

Deployment and Customer Protection Subgroups

Overview

The Deployment and Customer Protection subgroups were tasked with identifying, reviewing, categorizing and prioritizing actions, processes, policies, standards, and communications necessary for a successful and cost effective development of a Michigan smart grid. For reporting purposes, the Deployment and Customer Protection subgroups were combined because of the topical overlap.

Smart grid issues are complex and the Regulatory Policy subgroups often addressed the same issues, but from different perspectives. For example, the issue of meter security will ultimately require review by almost all subgroups. The Deployment subgroup reviewed meter security, as did the Customer Protection subgroup. However, while the Deployment subgroup focused on recommendations and goals related to the physical installation of equipment and networks; the Customer Protection subgroup focused on issues surrounding the protection of data and hardware.

These meter security issues are relevant to customer programs, rates, product offerings, etc. Therefore, it was agreed that both subgroups needed to address many of the same issues, distinguishing each issue as being either a Primary Issue (required to develop and implement the key recommendations) or a Subordinate Issue (needed to be addressed as part of a secondary recommendation). An overview of all of the cross-cutting issues that the Collaborative addressed in the workgroups is provided in Appendix C.

Utility Deployment Plans

A deployment plan should be the roadmap that is guided by the long-term vision for grid modernization. Deployment plans will provide the Commission with details of each utility's plan for grid modernization with specific consideration to the individual utility's priorities and distribution system needs.

Primary Issues:

- Utilities should provide their smart grid vision statement.
- Utilities should provide MPSC with a deployment plan that documents a smart grid roadmap that is consistent with their vision statement.

Subordinate Issue:

- Engage in forward planning that will enable a coordinated customer education and communication plan.

Meter Issues – Standards and Customer Education

The workgroup recognizes customer concerns related to the features and advantages of smart meters. Utilities will need to select and install smart meters that enable smart grid programs and provide reliability benefits for customers. Furthermore, utilities should select and install meters that are both compliant with national standards and provide automated features that contain full operational data security. Full disclosure of information from credible sources needs to be made available to utility customers related to meter education, i.e., data security and safety awareness, including, but not limited to radio frequency (RF) concerns. This issue will be more fully addressed in the Customer Programs and Communications section.

Primary Issues:

- Utilities should select meters using internal component designs that detect outside intrusions and enable isolation of affected equipment.
- Utilities should select meters featuring automated key exchange and secure firewalls.
- Utilities and vendors should be required to comply with standards contained in the Codes and Standard section of this report and other nationally recognized operational procedure security standards.

Subordinate Issues:

- Investigate the use of an independent party or federal organizations to develop and promote meter education and meter safety awareness.
- Implement customer education covering issues such as meter risk and benefits. Promote overall smart meter awareness. Education programs that are structured using Customer Programs and Communications Framework should be developed and implemented.

Plug-in Electric Vehicles

PEVs present new loads for the utility industry. These loads require different management attention than typical customer loads. For example, based on customer research, most customers do not mind shifting PEVs charging to nighttime. This new load can also be treated as a new demand response load. PEVs related policy topics include peak charging load, vehicle-to-grid and vehicle-to-home. These issues were discussed by the Distribution and Grid Applications Workgroup and by the MPSC's Plug-in Vehicle Taskforce. While the increase in PEVs' use has other policy implications (air quality regulation and transportation road taxes), these are outside the scope of this report.

Protection of Customer Usage Data

Customer protection issues need to be addressed with customers before and after the deployment of smart grid hardware and infrastructure. Protection of customer usage data includes the issues of customer confidentiality, data privacy, and allowing third party access.

In the future with the collection of detailed data through AMI, current utility practices of data privacy will continue to be followed. As with retail open access today, customer usage data will still be considered private and utilities will not release customer specific data to third parties without signed authorization from the customer. Stakeholders agree that the customers should maintain their rights to their data and that the utility should remain responsible for the collection, maintenance and security of customer data.

Customer protection is an issue that must be addressed to assure smart grid deployment success. Customers need to fully understand what smart meters are: their function, benefits, and that their data will continue to be held securely and confidentiality. If customers authorize sharing their usage data beyond the operational use by utilities or in aggregate form, further policies will need to be developed. When developing policies regarding customer data protection, efforts by the NAESB and NARUC to develop best practice guides for data access and privacy provide good reference points.

Utilities will still need to utilize customer usage data to achieve the customer and operational benefits from the smart grid investments. In addition, utilities require usage data and other information from smart meters to efficiently operate maintain and secure the electric distribution system. There are many potential applications for customer data utilization, including: rate options to customers based on their usage levels and patterns, identification of malfunctioning customer equipment (a motor load that is continuously running), and identification of highly loaded utility equipment, etc.

Primary Issues:

- The Commission should approve a rule that standardizes the protection of AMI customer usage data for all utilities.
- Utilities should develop a plan for action in the event of a customer data breach including a notification procedure for both customers and the Commission.
- The Commission should develop a clear policy that defines permissible and non-permissible use of AMI customer data for utility operations.
- Utilities need to determine how and at what cost customer data can be shared with others once customer permission has been obtained.

- An option to allow third parties to purchase aggregated data as it relates to energy efficiency and other programs merits further exploration.

Subordinate Issues:

- A national standard should be sought to protect customers from unlawful data sharing practices.
- Utilities need to determine how to provide customer access to an individuals' own usage data.

Meter Capability

Future smart meters applications need to be made clear. Future meter applications need to be able to support home area network (HAN) functions. Customer protections preventing accidental disconnects need to be addressed as well.

The following principles for smart meter capabilities were drafted in 2008 in a combined effort of staff and utility representatives:

- Capable of supporting various price responsive tariffs;
- Capable of collecting energy usage data at a level that supports customer understanding of hourly usage patterns and their relation to energy costs;
- Capable of allowing access to personal energy usage data such that customer access frequency does not result in additional AMI system hardware costs;
- Compatible with applications that provide customer education and energy management information, customized billing and complaint resolution;
- Compatible with utility system applications that promote and enhance operating efficiency and improve service reliability;
- Capable of interfacing with load control communication technology; and
- Allow customer flexibility in payment options.

Billing Rules and Technical Standards

Stakeholders are exploring NAESB and the International Electrotechnical Commission's (IEC) Common Information Model (CIM) standards compliance for transactions such as pricing, scheduling and demand response. Billing rules for electric vehicle charging should be consistent across utility territories. Stakeholders also generally support a rewrite of the technical standards for electric service to include new smart meter enabled functions.

Primary Issues:

- Minimum functionality standards need to be established for Michigan that allow for a fully functional smart grid in the future.
- Each utility should file meter application availability with the Commission as part of its comprehensive deployment smart grid plan, including applications available to, or affecting, customers as part of its tariff filings.

Subordinate Issues:

- Coordination between meter capability and any changes to the billing rules and technical standards should be maintained.
- A timeline should be explored regarding deployment of AMI meters, and availability of dynamic pricing.

Remote Connect and Disconnect Policies and Rules

Stakeholders generally agree that the effect of smart meter enabled remote connect and disconnect functionality needs to be addressed with potential AMI deployment. The Collaborative needs to further investigate the current billing rules to determine if there is a need for changes in: customer notification of electricity disconnection, guidelines for customers to avoid disconnection, procedures for power restoration, and fees for connect/disconnect services. The ability to remotely connect and disconnect customers does not invalidate customer protections established in billing rules.

Sharing of Smart Grid Networks

While not an initial deployment issue, network sharing may be viewed as an issue for consideration and action. Avoidance of dual networks in the same geographic areas when operationally and financially viable should be a long-term smart grid planning goal for Michigan. Network sharing will result in reduced costs and increased program efficiencies. Utilities have discussed this for several years and several operational and financial issues need to be overcome to make this a reality. Policy actions at the federal level should also continue to be monitored.

There will need to be billing between utilities for meter-related services, due to the number of gas and electric meters in overlapping areas for each utility. There may be justification for some standalone networks as is the case in California. Southern California Gas was able to provide justification for a standalone gas meter communication network in both San Diego Gas & Electric and Southern California Electric areas due to the complexities of sharing meter networks of incompatible technologies and day-to-day operational complexities.

Primary Issue:

- Review service quality billing rules regarding remote shut-off and restoration.

Subordinate Issues:

- Suggest staff develop a matrix that identifies utility service areas for both gas and electric.
- Review overlap issues (e.g., multiple utilities serving an area).
- Explain obligations applicable to all utilities (all gas and electric utilities with overlapping territories to come to mutual agreement on services provided by whom).

Prepayment Options

A prepayment program allows customers an option to purchase a specified amount of electricity in advance of its use. The program could allow for automatic disconnection of service when the amount of electricity usage exceeds the amount purchased. Prepayment can provide an alternative to deposit requirements for utility service and may reduce the utility's credit and collections costs. Prepayment may also help a customer reduce their consumption of electricity.

At a minimum, operation of a prepayment program would need to provide: 1) 24/7 customer access to his/her actual electricity usage and remaining credit, 2) a way for the customer to purchase credits, and 3) a connection between the customer and utility to signal when credit is depleted and restored. The costs associated with a prepayment program may be high relative to savings realized by the operating utility. Prepayment may become a realistic optional service with AMI technology and supporting IT infrastructure. Stakeholders are currently monitoring prepay activity throughout the country.

Primary Issues:

- Current rules do not address prepayment, but stakeholders should continue to investigate prepayment options and rule development.
- Rules should address fees for specific services, deposits, plan specifics, customer access to account information, service disconnection and restoration, utility responsibilities, customer responsibilities and potential third party management services.
- Through prepayment pilot projects, utilities need to determine if a voluntary prepayment program would be of benefit to their customers and to the utilities.

Waiver of Meter Testing

The current meter testing requirements are costly and unnecessary considering the inherit accuracy of the current generation of smart meters which are pre-tested. Direct meter installation may be a better utilization of resources than the current process of testing large numbers of meters. It is anticipated that a waiver of meter testing requirement should be reviewed.

Measurement, Assessment and Reporting

With any new technological venture, there is a learning process and an assessment and reflection of this process to ensure smart grid benefits are being utilized effectively. The investment in digital technologies requires measurement and clear understanding of benefits which further engages stakeholders, protects customers and allows advanced uses of a modernized electrical grid. Metrics need to be clearly developed and used to verify effective smart grid deployment.

Primary Issue:

- Utilities and the MPSC need to collectively identify the metrics for the smart grid that are both qualitative, and quantitatively designed to measure customer benefit[6,7]

[6] Guidebook for ARRA SGDP/RDSI Metrics and Benefits, June 2010.
[7] Software Engineering Institute, Carnegie Mellon University, CMMI, http://www.sei.cmu.edu/cmmi/

Cost Benefit Subgroup

Overview

The purpose of a cost benefit framework is to offer a mutually recognized (regulator/utility) methodology for presenting the costs and benefits associated with smart grid investments while not requiring the utilities to use a specific cost benefit model. The objective of the cost benefit framework is to provide consistent economic comparisons of smart grid investments. Developing a framework in lieu of a standardized model allows utilities to maintain some flexibility while providing guidance of acceptable attributes for regulatory purposes. This cost benefit framework is to be used as a guideline for utility business cases intended to justify smart grid investments.

Cost Benefit Framework Recommendations

As part of a defined cost benefit framework, certain common cost benefit model principles are recommended for smart grid business case analysis. It is recommended that a utility's smart grid cost benefit model reflect the following set of common model principles:

- Model should be self-contained within Microsoft Excel.
- The model should clearly define and support all assumptions and inputs (i.e., cost escalators and inflation percentage, lifecycle evaluation period, etc.) made in the estimation of included costs and benefits. (For complex models this documentation may be accomplished outside of the model.)
- Variables and model inputs should be identifiable and traceable.
- Cost benefit modeling should convert future expected cost and benefit revenue streams into a Net Present Value (NPV) amount using appropriate discount rate(s).
- Model should clearly provide a defined perspective for analysis such as utility cash flow or customer cost-benefit based upon revenue requirements.
- Measure and capture all incremental costs and benefits to be realized including timing of such benefits and costs.
- Allow for inclusion of sensitivity analysis on key assumptions contained within the model to account for uncertainties.
- Embedded financial modeling – should be clearly segregated and be in a standard financial format to facilitate reviewing.

Cost Benefit Model Attributes

Costs

The costs associated with smart grid development are primarily accrued in the early stages of deployment and therefore easier to quantify. These costs are specific to the smart grid investments and necessary for full benefit realization throughout the project lifecycle. The following list of potential cost categories aligns currently accepted accounting practices and outlines the anticipated costs necessary in implementing a smart grid. The list is not exhaustive and should be viewed as a starting point for utilities attempting to capture their smart grid costs.

<table>
<tr><th colspan="3">Potential Costs of Smart Grid</th></tr>
<tr><th>Capital Costs</th><th>O & M Costs</th><th>Other Costs</th></tr>
<tr><td>Direct Capital Costs
○ Materials
○ Labor
• Installation
• Project management
• Software development
○ Hardware
▪ In-home display
▪ Smart appliances
▪ Smart meters
▪ Communication Devices
▪ Reclosers
▪ Computers
▪ MDM Systems
▪ Synchrophasors
▪ Volt/Var Regulator
○ Software
Indirect Capital Costs
○ Overhead (Labor/Non-Labor)
○ AFUDC
○ Contingency
○ Inflation Factors</td><td>Operation and Maintenance
○ Labor
○ Software support
○ Hardware support
○ Startup costs
○ Customer engagement
○ Customer education
○ Taxes
○ Deferred costs
○ Amortization costs</td><td>Stranded Legacy
Equipment</td></tr>
</table>

Benefits

By definition, a smart grid benefit is one that connotes a positive change resulting from a smart grid function implementation. Smart grid benefits should be categorized into three specific categories based upon the entity that realizes the benefits (utility benefits, customer benefits or societal benefits). Smart grid benefits have the potential to vary greatly from utility to utility based on technology selection as well as customer demographics. Recognizing these variations allows utilities to develop proprietary estimation methodologies based on their deployment plans. These methodologies should accompany the benefit estimations for regulatory purposes. The utility needs to quantify and monetize the individual types of benefits.

Potential Benefits of Smart Grid		
Utility Benefits	**Customer Benefits**	**Societal Benefits**
Avoided capital investment Reduced uncollectibles Reduced generation operation costs Reduced ancillary service cost Reduced equipment failures Reduced distribution maintenance costs Reduced distribution operations costs Reduced electricity losses Reduced sustained outages Reduced minor and major outages Reduced restoration costs Reduced $CO2$, $SO2$, NO_x emissions Fewer estimated bills Faster customer account service Reduced read to pay time Increase asset utilization	Improved power quality Reduced outage duration Access to usage information Ability to manage usage based on costs Flexible rate structures Prepayment options Timely move in/move out processes Home area networks Smart charging of electric vehicles Net metering for renewables Reduction of estimated bills Better customer service Reduced theft subsidization	Lower Emissions Enabling new markets Decreased oil dependence Enabling Electric Vehicles Enable renewable energy sources

Due to the complex scope and multi-phase nature of smart grid, issues may arise around certain benefits and costs that cannot be easily quantified and monetized. Utilities should consider and address benefit issues including: permanent benefits versus one-time benefits, timing of benefit phase-in, ensuring benefits are not double-counted, identify uncertainties or potential risk factors that may mitigate benefits, benefits to specific customer classes, societal benefits, and potential environmental benefits. Utilities should also recognize and discuss cost issues such as: potential reduction in asset useful life, additional costs to implement future customer applications, higher than expected personnel required for management of information technology, and unanticipated expenditures for hardware or other capital.

In conclusion, all stakeholders are challenged with continual assessment of smart grid deployment benefits and costs. This process is essential in understanding the long-term impact of grid modernization. Stakeholders should periodically evaluate if the projected benefits associated with an approved smart grid investment are being realized for customers, the utility, society, and/or other stakeholders.

Cost Recovery Subgroup

Overview

As discussed in the "Historical Perspective" section of this report, the Commission established a set of initial smart grid cost recovery principles, in the order in Case No. U-16191. These principles address cost recovery of smart grid expenditures related to both the pilot and full deployment stages of the utility's programs. Collaborative stakeholders generally agreed that these principles were established to balance the interests of both utilities and their customers, while continuing to encourage the development of smart grid in the state of Michigan. These principles also define certain accounting practices, which may not fully align with existing utility accounting practices. Since these accounting guidelines are being addressed in ongoing rate cases, concerns regarding them were omitted from this report. The Collaborative focused on key areas where either clarification or modifications of the current non-accounting policies is needed. The Collaborative also discussed the need for new policies to be established in the early stages of deployment that would facilitate utility investment while adequately addressing the potential risks of smart grid investments.

Review of Existing Policy

Pilot Phase Versus Full Deployment Phase

The Collaborative acknowledged that there is not a shared understanding of what constitutes the “pilot” phase of a utility’s smart grid deployment versus the “full deployment” phase. This important difference needs to be resolved because existing Commission policy guidelines would treat expenditures incurred in the “pilot” phase differently from those incurred in the “full deployment” phase. Without definitions that articulate the unique characteristics of smart grid “pilots” as well as “full deployment” the transition point from pilot to full deployment becomes ambiguous.

The Collaborative acknowledged that there is not a shared understanding of the proper interpretation of the Commission’s conditions for full deployment. The Collaborative interpretations of these conditions ranged from requirements for Commission pre-approval of full deployment expenditures to the establishment of filing requirements in rate cases when utilities request recovery of full deployment expenditures. The Collaborative recommends the Commission provide clarity about the conditions for full deployment.

Smart Grid Enabling Policy

The Collaborative discussed several key areas where policy established in the early stages of deployment will facilitate utility investment while adequately addressing the potential risks of smart grid investments. These areas for consideration include: the appropriate timing for inclusion of smart grid expenditures in a utility’s rates; cost recovery of investments that are stranded as a result of moving to smart grid; cost allocation methodologies; and the use of non-traditional cost recovery mechanisms.

Smart Grid Investments Versus Other Utility Investments

The subgroup discussed the nature of smart grid investments and whether they were significantly different from other utility investments designed to improve or modernize their systems. One perspective is that there is a higher level of risk in smart grid investments in that there is less certainty around how the technology will function over time and whether customer behavior will result in the expected benefits. Typically, utility investments have known benefits (increased capacity, increased reliability, etc.) that occur upon installation. Without additional safe-guards that align the recovery of cost and the realization of benefits, a disproportional amount of project risk is borne by the customer. Another perspective is that smart grid investments align with other utility investments necessary to maintain the integrity and reliability of the grid. Consequently, these investments should be considered for recovery in the traditional manner, i.e., a prudency review through the general rate case process. Commission policy should consider recovery of costs in rates that have appropriately considered the inherent risks to both the customer and the utility's shareholders.

The transition to a smart grid will require the early retirement of legacy equipment such as electromechanical meters prior to the end of their useful life. As utilities seek recovery of the costs of legacy equipment resulting from smart grid deployment, it is imperative that the regulatory treatment of these stranded investments is clearly defined. The subgroup was unable to reach a consensus policy recommendation on the treatment of stranded investments due to the differing perspectives of stakeholders regarding the risks of smart grid investments. The perspectives range from full recovery of remaining book value of assets that are retired, including a return on the investment, to allowing only partial recovery of the remaining book value of that asset. Cost recovery treatment of these costs should consider these perspectives in order to balance the interests of both utility and customer.

Non-Traditional Recovery Mechanisms for Smart Grid Expenditures

Stakeholder non-consensus regarding the differences between traditional investments and smart grid investments led to the exploration of non-traditional (rider/surcharge) cost recovery methods for smart grid purposes. The Collaborative examined the benefits and shortcomings of non-traditional cost recovery mechanisms used in other jurisdictions for potential applications in Michigan. The Collaborative could find no justification for using non-traditional recovery methods. There was stakeholder consensus that the appropriate methods for addressing the potential risks of smart grid deployment exist in the traditional (general rate case) process.

Smart Grid Cost Allocation

The subgroup initially acknowledged that the allocation of smart grid costs among customer classes should follow the tenets of traditional cost of service. Specifically, as has been the traditional practice among Michigan's utilities, the cost of providing service is allocated among customer classes based on the "cost causation" principle, whereby rates reflect, to the extent possible, the costs actually caused by the customer class from whom the utility seeks recovery. Upon further discussion, some stakeholders were concerned with the application of the existing historical methodology because it is expected that all customers, to some extent, will benefit by the deployment of smart grid, not just those customers for whom the specific investments are made. An alternative approach identified that attempts to allocate costs proportional to the benefits received seems plausible, however, there was acknowledgement among stakeholders of the potential difficulty in quantifying achieved benefits and assigning them to the appropriate rate class. Thus, stakeholders agreed that this issue requires further detailed discussion so that a consistent methodology that fairly allocates the costs of smart grid is established.

MPSC Oversight Policy: Reviews and Reporting

As utilities implement smart grid applications, the Commission will need to track utilities' progress and success of any smart grid technology installed. The subgroup identified the need for clear and concise reviews and reporting requirements in order to provide the Commission progress updates inclusive of insight into the customer value proposition of installed smart grid applications. While acknowledging these general regulatory reporting needs, the subgroup was unable to come to a consensus on specific smart grid investment reporting requirements and\or form(s). Visions of acceptable smart grid reporting requirements ranged from embedded smart grid reporting updates in general rate case filings to requiring utilities to file annual smart grid reports inclusive of tracking multiple program metrics. The subgroup suggested that the Commission adopt a consistent reporting requirements policy regarding smart grid programs that is not overly prescriptive but does provide adequate details in order to meet regulatory review purposes.

Recommendations

Deployment and Customer Protections

- Utilities to provide a smart grid vision statement.
- Utilities to provide a deployment plan that documents a smart grid roadmap that is consistent with their vision statement.
- Utilities should select meters that:
  - use internal component designs that detect outside intrusions and enable isolation of affected equipment,
  - feature automated key exchange and secure firewalls, and
  - follow recommended meter capability principles outlined in the Deployment and Customer Protection section.
- Utilities and vendors should comply with national standards for data and operational procedure security.
- Utilities should create and implement customer education plans.
- The Commission should provide policy about customer usage data for utilities that:
  - standardize the protection of AMI customer usage data for utilities, and
  - define permissible and non-permissible use of AMI customer data for utility operations.
- Utilities should develop a plan for customer usage data that:
  - establishes a procedure for customer data breach including notification procedure for both customer and the Commission,
  - establishes how and at what cost customer data can be shared with others once customer permission has been obtained, and
  - explores the issue of permitting third party purchase of aggregated data.
- Administrative rules should be reviewed or established for:
  - remote shut-off and restoration, and
  - prepayment options.
- Utilities should continue to assess prepayment pilot projects and determine customer value.
- Qualitative and quantitative metrics should be established to measure customer benefit resulting from smart grid deployment.
- Utilities should utilize the cost benefit framework recommended by the Cost Benefit subgroup.
- Utilities should consider complex and difficult to quantify costs and benefits.

- Utilities and MPSC should periodically evaluate costs and benefits throughout deployment.

Cost Benefit

- Utilities should utilize the cost benefit framework recommended by the cost benefit subgroup.
- Utilities should consider complex and difficult to quantify costs and benefits.
- Utilities and the MPSC should periodically evaluate costs and benefits throughout deployment.

Cost Recovery

- “Pilot” size and scope perimeters need to be defined.
- “Full deployment” needs to be defined, including clarification of conditions utilities need to meet referenced in the cost recovery policy principles in the Commission’s order in U-16191.
- Appropriate treatment of stranded assets that occur during grid modernization deployment needs to be clarified.
- Address smart grid cost recovery using traditional rate based recovery mechanisms (no riders or surcharges).
- Utilities and the MPSC need to collectively establish clear and concise reporting requirements designed to measure customer benefits.

Summary and Conclusions

The Regulatory Policy Workgroup explored the regulatory impact associated with smart grid deployment. Through this process, the workgroup identified three areas of focus: deployment and customer protections, cost benefit framework, and cost recovery. Each subgroup offered unique perspectives to the subsequent topics.

The Deployment and Customer Protections subgroup identified several smart grid policy impacts that require attention in the near term. The workgroup concluded that there is a strong overlap between the need for customer protections policy and policy that address potential deployment issues. Many of the policy recommendations protect both the customer and the utility by clearly establishing smart grid guidelines, enabling thoughtful future planning, and providing protection against stranded investment.

The Cost Benefit Framework subgroup identified the attributes of a cost benefit model specific to customer benefits, utility benefits and cost characteristics. In doing so, the subgroup recognized the need for consistency within the context of a financial model while allowing utilities freedom in defining their specific cost benefit models. Further investigation is warranted to determine if policy is necessary to create financial model consistency.

The Cost Recovery subgroup identified several smart grid policies where stakeholder interpretation differed greatly. The group identified aspects of smart grid cost recovery that were uncertain and agreed that policy would be appropriate to address these issues. Areas of focus included pilot expenditures, full deployment expenditures, risk sharing, stranded investments, and applicable accounting practices for smart grid investments.

Throughout the collaborative process, all three subgroups identified the need for modification to existing administrative rules, Commission orders, and state legislation. Further investigation is necessary to fully develop specific policy recommendations. Continued efforts in the policy development area will help guide a consistent smart grid approach in Michigan.

Customer Programs and Communications Workgroup Report

Purpose and Focus

Smart grid deployment will have a direct impact upon the relationship between utilities and their customers. AMI is the most visible component of smart grid, allowing for two-way communication. The combination of advanced meters and applications has the potential to allow customers to choose how and when they use energy.

Successful smart grid implementation is grounded in customer understanding and acceptance of its benefits. Education and communication of relevant information is critical to moving these goals forward. For the purpose of this workgroup, education is defined as information that drives the adoption of products, services, and programs. The purpose of education is to increase customer knowledge and encourage behavioral change.[8] The importance of an effective message cannot be overstated. Below is an outline of the defining principles for creating cohesive customer programs and communications:

- Creating basic customer awareness about the purpose and impacts of smart grid.

8 Metering International Issue 1, *The Five Qualities of Effective Smart Grid Customer Education*, 2011

- Delivering a unified statewide message about smart grid and related changes to the electric system.
- Understanding best practices and lessons learned from other utilities and pilot programs to help define a communication plan.
- Understanding the Michigan customer and defining a state-wide message which relates specifically to them.
- Promoting incentives which drive customer behavior changes.
- Identifying opportunities and barriers to customer adoption of smart grid.

The focus of this section of the report is to:

- Define current status of Michigan utilities' smart grid customer communication programs and education practices.
- Identify the "best" practices for customer education.
- Establish a future vision and principal themes for Michigan customer communication about smart grid and its benefits.
- Recommend policies intended to maximize the customer benefits of smart grid.

Historical Perspective

Historically, utilities have needed to inform customers about new customer programs or changes in service. In general, customer behavior changes were not necessary. In contrast, smart grid assumes the customer will become a participant in energy management.

In summer 2009, all Michigan utilities launched their first significant energy efficiency program portfolios in more than a decade. The purpose of these programs was to provide products, services, and information for both residential and business customers to help them take greater control of their energy use and reduce costs. Utility benchmarking research and focus groups concluded that:

- Customers are motivated to take advantage of energy efficiency programs by the possibility of saving money on their energy bills more so than societal issues, such as improving the environment.
- A program identity was needed to create a common tie among many planned campaigns.
- A web site would function as a critical hub for informing customers on a broad array of programs and energy efficiency actions they could take on their own.

Utilities built awareness using a variety of media including short television commercials, radio ads, billboards, and dynamic web objects. In addition, bill inserts, news releases, media interviews, and employee communications were used to explain more details of the programs. Utility web sites were launched, giving customers one place to go for details about rebate programs and energy efficiency education. In 2010, utilities introduced several new communication tools to further encourage customer participation:

- Additional cost savings calculators,
- Educational videos featuring utility employees discussing relevant energy-efficiency topics,
- A Facebook page featuring daily tips, links to related websites, short video podcasts, and questions designed to engage visitors in energy efficiency conversations,
- Digital campaigns and banner ads. This showed better than average click-through rates to the web sites during campaigns,
- Participation in relevant community events, direct mail of educational brochures, postcards directing customers to the web site, and emails with links to the web site, and
- Use of a grass roots approach to spread awareness of their programs.

Current Status of Customer Programs and Communications

DTE Energy

Direct Load Management

DTE has had direct load management programs for many years. These programs control both air conditioners and water heaters by limiting energy usage by these appliances during peak times. The approximate enrollment in these programs is 259,000 customers with the majority enrolled in air conditioning load control.

SmartCurrents^{SM}

SmartCurrents^{SM} is DTE's integrated smart grid solution. It includes the installation of AMI, upgrading electrical circuitry (Smart Circuit) and the addition of smart home technology.

AMI

In 2008, DTE installed 6,000 electric and 4,000 gas AMI meters in the island community of Grosse Ile. This community was selected because of its distinct boundaries and mix of both gas and electric service customers, making it an ideal location for testing the technology. The AMI pilot also gave DTE the opportunity to involve the community. Prior to installing meters, DTE held several meetings with public officials and the local residents to explain why it was installing the new meters. Fortunately, this community already had experience with similar technology because AMR water meters had already been installed on Grosse Ile. Prior exposure made it easier to gain customer acceptance of AMI technology. DTE has installed approximately 500,000 meters, as of September 2011, in southeastern Michigan and are on track to install a total of 800,000 meters by June 2012.

Smart Circuit

The Smart Circuit project involves upgrading electrical equipment, and installing a communication network and a centralized control system. The upgraded electrical equipment will establish advanced circuit loop schemes that will enable quicker restoration of problem circuit areas. The communication network will transmit information from the new advanced electrical equipment to the central control system at DTE. The goal of the program is to provide DTE with a real-time, complete and connected picture of the electrical distribution system enabling the utility to provide more reliable electrical service for customers. DTE is taking its first steps toward this goal by installing smart circuit technology on 55 circuits and 11 substations in north Oakland County.

Smart Home Pilot

Starting at the end of 2011, DTE will launch a pilot for approximately 2000 existing AMI customers, to study the effectiveness and customer acceptance of Home Area Network (HAN) devices. The pilot will include customers with and without enabling equipment. All groups are to receive information about rates, access to on-line usage presentation, tips to reduce bills and information about peak demand. In addition to learning about the use of the HAN technology, DTE also plans to test if information alone will motivate customers to reduce consumption. The products and services that will be available include:

- Customers on Dynamic Peak Pricing Rate (DPP) with no enabling equipment.
- Customers on DPP with programmable communicating thermostat (PCT) and /or In Home Devices (IHD).
- Customers with smart appliances, PCT and IHD.
- Customers on pre-pay billing.

Communication Strategy

- DTE is holding meetings with public officials and town hall style meetings with residents. Attendees are given information packets that include all materials sent to customers (installation letter, brochure and door hanger, and a video about AMI installation).
- Prior to installation, customers receive a brochure and informational letter about AMI, indicating that their meter will be installed within a few weeks.
- After installation, a door hanger is left at the customer site informing them that their meter has been changed and providing a number to call for questions.
- A website provides information on the program, how to read the meter, installation areas, FAQ's and links to relevant studies. It also includes information to help dispel customers concerns about privacy, accuracy of the meters and health concerns related to RF exposure.
- Customers in the Smart Home pilot will also have a website to provide specific information and education.
- On line usage information will be provided for all AMI customers as well as a rate comparison tool for those on DPP. They will also receive tips on how to save money.
- Technology Demonstration Center will be open by the end of 2011 to educate employees and other stakeholders on the technologies that DTE is investing in and to showcase energy efficient products.

Customer Segmentation

It is absolutely essential to understand that customers have unique characteristics. Not all customers are the same and when communicating with customers all stakeholders should keep this in the forefront. Examples of characteristics to recognize are: early or late adopters, energy use focused, do it yourself, and environmentally conscious. Awareness and utilization of key customer characteristics will make a more effective smart grid communications.

Lessons Learned

- Focus groups were conducted reviewing the information in the letter, door hanger and key messages to determine what information resonates with customers.
- Original door hangers and brochures did not provide enough information about how to read the new meter or clearly identify customer benefits.
- Need to educate employees on program, including benefits and information to dispel myths.

Key Messages

- DTE is launching SmartCurrents℠- new technology that puts customers in control of their energy use.
- DTE's SmartCurrents℠ gives customers the tools to use energy economically, efficiently and effectively.
- DTE's SmartCurrents℠ program will empower customers with information and new technologies that help people save money.

Consumers Energy

Direct Load Management Pilot

In 2010, CE launched a demand response pilot in Grand Rapids called "Peak Power Savers." The primary focus was to evaluate participants' response to approaches used to attract customers and to determine load reduction potential during critical peak periods.

Residential customers participating in the pilot gave permission to have load control switches installed at their air conditioning units. During a limited number of peak demand days, the air conditioners were cycled off and on and data was captured to determine actual load reduction impacts. In exchange for enrollment in the program, customers received an appreciation payment along with a modest rate reduction for a portion of their usage.

Upon completion of the program, a telephone survey was conducted and overall satisfaction with the program was high. In addition, a focus group session was held to gauge perception of the program and gain insights for improvement of future versions of the program.

Marketing and Recruitment

Direct mail marketing for the program included an enrollment form sent to 49,000 customers. Participants were offered an incentive for enrolling in the program and a rate reduction. These efforts resulted in an enrollment rate of 4.6%, with over 2,200 participants enrolled.

Based on surveys, the main reason for enrollment was to save money on energy bills (60%) and to help make a positive environmental impact (22%). One half of participants said they would have enrolled without the $25 incentive offering.

An informational website was launched; a program guide and a magnet with a toll free 800 number was sent to all new enrollees. Throughout the program, most (69%) respondents indicated they did not use the program guide or 800 number. Satisfaction with these resources was high among those who did utilize them.

A small portion (2%) of participants elected to de-enroll from the program with most of these due to their moving to another location. A process was developed to offer enrollment to the newly moved in customers.

Throughout the summer months, eight critical peak events were declared. As many participants were not aware of when the events occurred, customer savings were realized without causing an impact to customer lifestyle.

Customer Research Results

A telephone survey and focus group was conducted among participants upon completion of the 2010 program, overall satisfaction with the program was 83% with only 2% dissatisfied. The main reason for dissatisfaction was due to insufficient savings. Only about half of respondents (45%) indicated that their savings expectations were met by participating in the program. Nearly one-third (32%) was unsure whether their expectations had been met. The majority (92%) indicated that they would participate in the same program again.

Analysis of the pilot results showed an approximate 1 kW (at the meter) potential load reduction per customer on a critical peak day. These results are in line with the experience of other utility companies as a result of a direct load control program.

Dynamic Pricing Pilot

The Residential Dynamic Pricing Pilot was marketed to customers as “Personal Power Plan.” During periods of peak demand, load curtailment depended upon customers’ willingness to reduce their energy use.

Three main categories of treatment were tested in a controlled experiment. In the first category, information was provided to customers about usage and the timing of critical events. In the second category, technology such as paging to notify customers, as well as the option to set predefined reduction levels, was used. In the third category, the impact of offering alternative rates to customer was tested. The pilot was conducted in the Greater Jackson area. The only participants outside of Jackson County were the 115 customers in the Hawthorne Control Group.

The marketing strategy consisted of direct mail, and outbound calls by an implementation vendor. Customers could receive up to two appreciation payments; a check for $50 in appreciation for enrolling in the program, and an additional $100 as a thank you at the completion of the program. Customers were also allowed to keep the intelligent communicating thermostats at the end of the pilot. The total number of active customers enrolled at the start of the program was 751, which exceeded the initial target by nearly 10%.

Although customer reactions varied, customers were most likely to conserve energy during a critical peak event if they were participants in critical peak pricing with enabling technology. Enabling technology included intelligent communication thermostats (ICTs) receiving critical peak notification, and web based platforms for review of usage patterns. Other communications channels such as outbound calls, e-mails, and short messaging service (SMS) text messages were leveraged to notify customers of critical peak events.

Indiana Michigan Power Company

Smart Meter Pilot Program

I&M has customers in Michigan, however its smart meter experience to date has been in Indiana. In 2008, I&M conducted a Smart Meter Pilot Program (SMPP) in South Bend, Indiana. The program was designed to develop, implement and measure the potential benefits of smart grid technologies and programs.[9]

Program Design

Approximately 9,600 AMI or "smart" meters were deployed for commercial and residential use. The infrastructure included an integrated two-way wireless communication network for all meter and grid management functions. Customers were provided an interactive web portal where they were able to view and analyze historical energy consumption information in hourly increments. During the pilot, customers were offered different innovative programs.

Communication and Education Strategy

Marketing and communication strategy was developed to educate residential and small business customers about the benefits of smart meters and to drive participation for demand response programs, which include Time of Day (TOD) rates (SMART Shift[sm]) and DLC (SMART Cooling[sm]). Marketing strategy was based on the following objectives: achieve demand response program participation goals, create awareness of smart meter technology and its benefits, and educate customers about pilot programs and how customers can manage their energy budget. Communication channels were limited to the geographic area of the pilot.

Lessons Learned

Marketing:

- Email is a viable and cost-effective communication channel for many customers. Emerging communication should be considered.

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[9] *Indiana Michigan Power Company Smart Grid Pilot Program; Process and Impact Evaluation Report*, March 29, 2011.

- Provide frequent information via direct mail about the benefits of the online web portal. Repeat the common message to customers as to how important it is to be engaged and knowledgeable about their energy usage and potential energy savings.
- Provide additional educational awareness about smart meter technologies and the service reliability benefits.
- Keeping the message targeted (one-on-one) to the SMPP customers involved in the pilot was a critical benefit to both the customer and the company.

Automated Metering Infrastructure:

- The meter and associated communication network performed reliably following resolution of initial technical issues.
- AMI deployments require a significant investment in back office information systems which take longer to design and deploy than the equipment installed in the field.
- Integration of multiple vendors is required to implement a functioning AMI system from energy usage collection through bill presentment.
- Vendors are in competition with each other and are reluctant to share technology.
- AMI network security must be built into the design of the solution and continual improvements are necessary to maintain an acceptable level of security.
- HAN and associated devices:
    - Significant improvements in the initial PCT performance and reduction in the installation time are necessary to improve overall reliability and reduce cost. HAN technology standards are still being developed. Robust and detailed design specifications with consistent interpretation will be required to limit current technology from becoming obsolete and encourage widespread deployment;
    - The ZigBee protocol[10], as initially specified and used within the SMPP, was restricted for use only in single family homes due to its range limitations. I&M is considering alternative forms of communication which may be more appropriate for future wide-scale non-urban and non-suburban AMI deployment; and
    - Once operational, the communication of event signals from the corporate back-office systems to the PCT was over 95% reliable.

[10] ZigBee protocol is a digital communication protocol based upon IEEE 802 standard for personal area networks.

Customer Programs

- Customers will override the direct load control events more frequently if there are no consequences to their actions such as loss of incentives.
- Customer overrides significantly reduce achievable demand savings.
- A two degree increase in indoor temperature setting does not provide a 1 kW load reduction for a full two hour period on hot days.
- A four degree increase in indoor temperature setting will provide a 1 kW or greater load reduction for nearly four hours on hot days.
- Customer participating in TOD tariffs on hot summer days altered their energy consumption patterns. These customers exhibited energy consumption patterns to a mild summer day.
- During an indoor temperature setting increase event, the majority of customers will notice the temperature change but most will not consider the comfort change significant.

Conclusion

At the conclusion of the SMPP, I&M believes that a full deployment of an integrated smart grid, which includes smart meters, grid management controls and advanced customer programs, can be beneficial to all stakeholders. The timing and cost of this full implementation will depend on many factors that continue to evolve including:

- Active residential customer participation and understanding of cost energy benefits from a smart grid application.
- Engagement of commercial and industrial customers to participate and understand cost energy benefits from a smart grid application.
- Development of a business case that encompasses the impacts to the utility, customer, society, and the environment.
- Deployment of distributed resources in distribution grid such as electric transportation, distributed generation.
- Requirements for competing government mandated capital investments such as Hazardous Air Pollutants rules.
- Future compliance with carbon regulations/legislation.
- Compliance with energy efficiency and peak demand reduction targets.

I&M believes the next practical step in the evolution of a smart grid deployment is to use our existing SMPP installation to determine how to increase customer participation. Although, this pilot program identified some technical challenges, we believe they can be overcome in time and are not prohibitive to further deployment. However, absent some compelling reason to believe customers will embrace the potential benefits of this technology, I&M concluded the benefits will not outweigh the costs.

National Lessons Learned

The Customer Programs and Communications Workgroup looked nationally to lessons learned from smart grid pilots and deployments. The effort was helpful in determining the best methods to effectively educate customers. Smart grid programs at Central Maine Power, Oncor, Pacific Gas and Electric Company, Salt River Project, OGE Energy Corporation, and others were analyzed.[11] The workgroup drew the following conclusions regarding necessary elements for an effective communication strategy:

- Communications should be transparent.
- Information must be accessible.
- There needs to be multiple communication avenues.
- Messages must be customer-focused and timely.

State of Michigan Customers

Michigan is a demographically diverse state. The importance of understanding the customer cannot be overstated. Michigan customers represent a wide spectrum of social and economic sectors. Utilities can create targeted messages based upon customer interest through segmenting the service population. Segmentation allows the utilities to target messages that speak directly to the interests of the customer and cross-cut traditional boundaries. For example, residential and commercial customer messages that incentivize owners, renters, technology enthusiasts, thrifty buyers, and environmental conservationists will motivate behavior change. Benefits defined by the interests of the segment will encourage customer engagement.

Commercial and Industrial (C&I) customer classes hold significant opportunity for peak load shifting. Manufacturing, education, health services, and retail trade combined comprise over half of the C&I

[11] See Appendix D for a complete list of company websites.

customers in Michigan. Communication and education about program benefits for the C&I customer class has the potential to change the demand profile greatly. In conjunction, the benefits may have a potential to provide economic growth opportunities for C&I customers.

Customer Concerns and Customer Education

The Collaborative recognizes customer concerns regarding smart meters emitting RF signals and data privacy. While the majority of customers are in acceptance of AMI, the MPSC has received a minimal number of customer contacts. Utilities will need to address these concerns with their customers. Customer education efforts should address the benefits of smart meters, the perceived risk associated with RF, the scientific information that defines smart meter RF emissions, and the utility privacy policies associated with customer data privacy. Full disclosure of information from credible sources needs to be made available to utility customers.

Customer education programs that address meter risks and benefits should use the Customer Programs and Communication Framework shown below. Stakeholders are encouraged to investigate the use of third party or federal organizations to develop and promote meter education and RF/meter safety and awareness.

Customer Programs and Communication Framework

Customers, utility employees, regulators, and other stakeholders need to be well-informed about the many facets of the smart grid; expectations must be translated in a meaningful way. Communicating the smart grid story realistically and honestly, without over-promising benefits will build trust between all parties. Assertions about the benefits of smart grid should be aligned among utilities, academic and agency research and legitimate media coverage to avoid unsubstantiated claims.

While some customers will be excited about increased reliability, potential for saving energy or environmental benefits, each customer should have the information to determine his or her own level of participation and engagement with the rates, programs and services that will be available. Therefore, the vision of Michigan's smart grid communications recommended by the workgroup is:

> All Michigan customers, utility employees and other stakeholders are well-informed, aware and accepting of the need for continuous improvement of the electric grid.

In order to achieve this vision, consistent key messages should be incorporated whenever communicating.

Key Customer Focused Messages to Utilize in Smart Grid Communications

- Smart grid means modernizing the electrical system to serve customers better. Improvements will include upgrading meters and electrical circuitry building a high-tech power infrastructure with the platform to better explore advanced energy technologies. Once upgraded meters are installed, customers receive the benefits of improved billing and more accurate outage information.
    - Meter information will be transmitted automatically to the electric utility, eliminating the need for a meter reader to manually read the meter. This means fewer estimated meter reads and more accurate bills.
    - Utilities will know that the home or business is without power sooner. This information will allow them to determine the full extent of an outage and restore power more efficiently.
    - Utilities will have the ability to pinpoint specific areas where power is out, enabling them to provide a more accurate restoration estimate.
- Smart grid will make it possible for the utility to explore developing future programs, rate options and online or in-home tools, making it easier for you to understand and manage your energy use to help save you money.

Guiding Principles

Effective customer education is imperative for future smart grid deployment in Michigan. Successful education of smart grid information is rooted in clear and consistent messages. With this goal in mind, the Collaborative distilled six guiding principles for accurate and effective communication of smart grid benefits to the customer.

- Messages must be customer focused:
    - Dynamic 2-way customer communication - customer feedback is received and analyzed, leading to continuous improvements of message content. This process will build trust with customers as communication dialog evolves between the utility and its customer.

    - Utility employees must be knowledgeable smart grid ambassadors, providing multiple contact points for the public.
    - Customer first - define smart grid advantages in ways that benefit customers in their daily lives.
- Messages for the customer must be easy to understand, truthful, and crafted with respect. Smart grid advancements should not be overstated; do not make promises that cannot be delivered. Information must be easy for the customer to find, using a variety of media and contact points.
- Utility messages to the customer must align with key Collaborative messages:
    - Consistent information targeted to customer segments increases customer awareness.
    - Timely - repeated messages must be provided to the customer at appropriate times, linked to the smart grid event that the message addresses.
    - Use multiple messaging channels - different customers interact with different media. Increase the opportunity for customer engagement by the use of multiple media.
- Understand the voices of customers and embed it into the communication process - Utilities need to clearly define customer segmentation, designing the messages to address their customers in a way that focuses on their customers' priorities.
- Each utility must coordinate their communication program with their deployment plan, reflecting events as they affect the customer.
- Recognize that customers' view on energy as a means to doing or obtaining the things they value. Customer interaction with smart grid must be simple and consume as little or much time as they wish to dedicate.

Communication Metrics

Two conclusions from national surveys on smart grid provide relevant starting points for a discussion about successful metrics for deployment in Michigan.

- Two-way communication - listening and responding are crucial parts to turning energy information into consumer action.
- Consumer education and acceptance will be essential keys to unlocking the sweeping economic and societal benefits that a nationwide smart grid can deliver to an energy-hungry nation. . . . Consumers will need to accept and embrace the concept that realizing the

benefits of a smart grid is going to require an open, collaborative effort on their part—and that their participation is as much an integral part as any piece of "smart" technology.[12]

Metrics for communication plans often include cadence, reach, depth, media coverage, issue salience, and customer satisfaction. The statements above suggest a more ambitious goal for successful smart grid rollout. Smart grid benefits rely on a significant change in how utilities must do business—and how consumers think of energy. Metrics, therefore, must be focused toward capturing customer engagement: awareness, understanding, acceptance, adoption, and satisfaction. This qualitative data leads to customer surveys, focus groups, and customer feedback loops as key diagnostic tools for utilities to use.

Recommendations

- Increase customer awareness using the newly developed communication framework.
- Create and implement customer education plans, which align with the SG Communication Guidelines.
- Understand the customers including preferred modes of communication and interests related to smart grid.
- Stakeholders should work to design concise metrics measuring the effectiveness of customer communication efforts, education programs, and engagement results.

Summary and Conclusions

Communication plays an important role in educating customers on smart grid. Stakeholders understand that education programs require resources. Policy discussion that addresses customer education is cross-cutting with Regulatory Policy's Deployment and Customer Protections subgroups. All identify education programs as critical for both customers and employees so they can understand changes and make informed decisions.

[12] http://www.slideshare.net/smtoday/smartgrid-and-the-customer-exerience

Distribution and Grid Applications Workgroup Report

Purpose and Focus

The smart grid has the potential to enhance how electric customers interact with the distribution system. Presently, customers have little interaction with the electric grid other than manually turning appliances, lights and other loads on and off, adding more loads to it, and receiving a monthly bill for the service. A smart grid has the potential to allow customers to be more economic in their energy consumption, own and utilize distribution system resources, such as solar panels and PEVs, and receive more reliable service. All of these opportunities depend on the development and installation of various technology applications, and the Distribution and Grid Applications Workgroup was created to explore and discuss these applications, including the benefits and challenges associated with them. Specifically, this workgroup focused on the following topics:

(1) A historical perspective on the major groups of smart grid applications – AMI, customer applications, demand response, distribution automation, and distributed resources.
(2) Provide an inventory of the current deployment status of major smart grid applications in Michigan utilities.
(3) Create a glossary of smart grid applications that defines the application, its benefits and impacts, what stakeholders will be affected by the application, and its likely regulatory impact.
(4) The current prioritization of the applications among utilities, along with alternative communication configurations and integration of PEVs.
(5) Short-term and long-term recommendations for advancing distribution and grid applications in Michigan in a prudent manner.

The Distribution and Grid Applications Workgroup brought together many organizations with considerable experience and expertise. Participants included investor-owned utilities CE, DTE, and I&M, along with the MPSC, MISO, energy consulting firm Five Lakes Energy, and the nonprofit Next Energy. Together, these organizations shared their perspectives in discussion of the future of the distribution system in Michigan.

Historical Perspective

In order to properly understand the smart grid applications that are described throughout this report, a description of the technological origins and progression of the major categories of smart grid applications are required. These major categories are AMI, customer applications, demand response, distribution automation, and distributed resources.

History of Electric Meters and AMI:

- Traditional electrical meters were first developed in the late 1800s as a means to modernize the billing of electrical use. In 1888, Hugo Hirst of the British General Electric Company introduced it commercially into Great Britain.[13]
- In 1889, the first AC kilowatt-hour meter was developed by Hungarian Ottó Bláthy. The AC kilowatt hour meters used throughout the 20th century and still today operate on the same principles as Bláthy-meters (as they are commonly known).[14] [15] [16] [17] [18] These meters must be read manually on a monthly or yearly basis.
- In 1972, Ted Paraskeavkos first developed a sensor monitoring system that used digital transmission for meter reading capabilities for all utilities (as well as fire, security and medical systems). In 1977, Paraskevakos launched Metretek, Inc. and produced the first fully automated, commercially available remote meter reading and load management system.[19] [20] This was the beginning of Automatic Meter Reading (AMR) and its use in electric utilities.
- Early AMR systems consisted of walk-by or drive-by readings of electric customers' meters and only collected meter readings electronically and matched them to the appropriate accounts. As more advanced technology became available, additional data was able to be captured, stored, and transmitted to the main computer with the metering devices being controlled remotely.
- AMI represents networking technology that enables two-way communication between meters and central system. These meters are referred to as "smart meters" because in addition to

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[13] Whyte, Adam Gowans (1930). *Forty Years of Electrical Progress.* London: Ernest Benn. P 31, 159
[14] Eugenii Katz. "Blathy". People.clarkson.edu. Archived from the original on June 25, 2008.
[15] Ricks, G.W.D. This paper appears in: Electrical Engineers, Journal of the Institution of Issue Date: March 1896 Volume: 25 Issue: 120 On page(s): 57 - 77 Digital Object Identifier: 10.1049/jiee-1.1896.0005
[16] The Electrical engineer, Volume 5. (February, 1890)
[17] The Electrician, Volume 50. 1923
[18] Official gazette of the United States Patent Office: Volume 50. (1890)
[19] U.S. Patent 3,842,208 (Sensor Monitoring Device)
[20] U.S. Patent 4,241,237 and U.S. Patent 4,455,453 and Canadian Patent # 1,155,243 (Apparatus and Method for Remote Sensor Monitoring, Metering and Control)

remotely collecting consumption data they can, in near real-time, report outages and power quality data.

History of Customer Applications and Demand Response:

- Demand response has been practiced to some degree by most electric utility service providers since the 1980s.
- Originally rooted in least-cost planning ideas developed in the 1970s, demand response came into general use with demand-side management in the 1980s due to resistance to large capacity increases in the 1970s.
- Traditional demand response programs consist primarily of contractual agreements with large power users who agree to make their loads "interruptible" in return for either rate reduction or bill credit. The triggering mechanism in such programs can be as simple as telephone calls from the utility to interruptible customers. Such load reduction can be arbitrary and for potentially long duration.
- Some utilities have also developed demand response programs that aggregate load reductions from a large number of customers, typically focused on one or two classes of loads such as air conditioning or water heaters. These are typically executed through automated communications to specialized control devices provided as part of the program. Such load reductions are typically for a few minutes after the load reduction request, after which load returns to normal. Systems that utilize one-way communication for load reduction signal distribution provide no means to verify that the load reduction actually occurred.
- Demand response has a similar purpose to, but is generally distinguished from dynamic demand, conservation voltage reduction, and critical peak pricing. Dynamic demand has load-making devices that respond automatically to locally-observable conditions on the grid, such as frequency, rather than an overt request by the utility. Conservation voltage reduction reduces voltage by a few volts for all customers in a segment of the grid, which inherently reduces energy consumption by a wide variety of load-making devices without any selectivity as to customer or device type. Critical peak pricing imposes a high price on all customers for power consumption at critical times but allows customers to choose how to respond to the high price.
- In recent years, several companies have developed demand response aggregation services as a business model. The utility contracts with the aggregation service provider for demand

response and the aggregation service provider then develops necessary arrangements with utility customers.

- CE currently has about 163 Megawatts (MW) of contractually interruptible load with several large customers. DTE currently has about 56,300 customers with interruptible hot water heaters totaling about 25 MW and 280,000 customers with air conditioners subject to cycle interruption totaling 220 MW on 85 degree days. In addition, DTE has approximately 350 MW of interruptible load with its C&I customers. I&M does not have any customers contracted for interruptible load reductions.

History of Distribution Automation:

- Very little of the electric grid has changed in terms of capability and design since the original components were set in place. It has been said that if Thomas Edison were around today, he would recognize virtually all of the major equipment used in the electric distribution system.
- The grid was designed to economically and reliably deliver electrical power over long distances so that generation resources would not have to be placed in areas immediately adjacent to the electrical loads that would consume the power. This required large capital investments to not only build out the grid but also to protect it from damage.
- During original grid build out, basic electromechanical grid protection equipment was installed to provide localized grid assessment, monitoring, and protection. This equipment had little ability to communicate with other remote protective equipment, which meant that grid equipment generally made decisions in isolation rather than with the benefit of real-time collective data from other contributing protective equipment. This led to very little change in the design and daily operation of the grid throughout much of its history. The overall result was a highly functional and operable system that met the societal demands of the time and provided adequate service for decades, but was seemingly inefficient and had room for improvement.
- Despite the presence of older equipment on the grid today, grid technology has progressed and evolved, albeit at a slower and more conservative pace than in other industries, as the electronics age has driven the capability and affordability to analyze, assess, monitor, and communicate large amounts of detailed data more quickly and more efficiently. Grid

electronic controls and measuring devices have gradually replaced the electromechanical style of equipment by providing the same basic functionality, only with expanded capabilities.

- Improvements in telecommunications technology, such as fiber optics, radio frequency and cellular technologies have also driven the ability of grid equipment to communicate with other remote devices and with remote grid operators more efficiently and effectively.
- Grid automation, coupled with near real-time communication capability from any point on the grid, stands poised to improve and enhance the basic functionality of the grid where detailed and timely information can facilitate better service to customers, near real-time decision making capability, the ability to integrate more diverse generation resources, the more efficient use of energy, and an optimized, more efficient grid.

History of Distributed Resources (Renewable Energy and Renewable Energy Storage):

- Distributed resources in the context of smart grid mainly refers to renewable energy, specifically solar and wind power, and electricity storage elements such as batteries. Renewable energy is defined as energy from sources such as biomass, biofuel, solar, wind, hydroelectric, tides, and geothermal heat, which are naturally replenished. Many forms of renewable energy have been used by humans for millennia. The smart grid has the most potential to improve the economics of solar and wind power.
- Solar power is a renewable resource that uses energy from sunlight. The two primary types of solar power are photovoltaics and concentrated solar power. Photovoltaics provide for the production of electricity directly from the conversion of sunlight. Concentrated solar power is used to heat boiler-driven power generation. Unless located in areas with near-constant sunlight during the day, such as the southwestern United States, solar power is considered an intermittent fuel source.
- Wind power is a renewable resource that uses energy derived from the conversion of wind energy into electricity. The value of wind resources is primarily based upon location and thus a requirement of utilizing wind power is the ability to transport the generated electric power to the load centers. It is very intermittent and diffuse compared with fossil fuels.
- Energy Storage may help compensate for these renewable sources' intermittency problems by storing electricity on a large scale for later use. Energy storage assists in balancing the system's intermittent generation sources (like wind and solar) and varying loads with controllable storage elements such as batteries. Other forms of energy storage are pumped hydroelectric, flywheel, compressed air and thermal. As the penetration level of electric vehicles grows and battery technology advances, the feasibility of using the vehicle batteries as storage and power sources increases. In addition, as more intermittent generation sources are added to the grid, the ancillary services (frequency regulation, voltage regulation, etc.) that can be provided by storage devices will become more important in the operation of the electric system.
- From a policy perspective, renewable energy has been advocated for in recent history as an answer to pollution concerns, supply constraints and environmental preservation. The momentum building from the 1900s to the 1960s launched the 1970s into an era of environmental clean-up.

- Public Utility Regulatory Policies Act (PURPA) was passed in 1978 allowing small power producers using renewable energy facilities that generate electricity to enter into power purchase agreements with rate regulated electric providers.
- The early promotion of renewable energy was reinforced in 2000 by the Michigan Renewable Energy Program. The program was designed to inform Michigan customers of the availability and value of renewable energy generation and the consequential reduced pollution.
- In 2007, introduced the 21st Century Energy Plan,[21] a statewide integrated resource plan assessing the projected need for new generation, which included renewable generation.
- Finally, 2008 PA 295[22] established a Renewable Energy Standards for Michigan. Michigan's renewable energy standard requires electric providers to achieve a retail supply portfolio that includes a minimum of 10% renewable energy generation by 2015.

Current Deployment Status of Smart Grid Technology in the Distribution System

An early exercise in the Distribution and Grid Applications Workgroup was for each investor-owned utility (IOU) participating in the Collaborative to provide a brief description of the implementation status of various smart grid applications within their territories. Each of these IOUs specified in a worksheet if they were implementing a particular application now, one to three years from now or in four years or more. Each utility also supplied comments to describe their plans in more detail. These documents can be found in Appendices E and F.

[21] Michigan's 21st Century electric Energy Plan, January 2007, http://www.michigan.gov/documents/mpsc/21stcenturyenergyplan_185274_7.pdf

[22] 2008 PA 295, htt://www.legislature.mi.gov/S(cp1us3451us34514zcz45nu111aud))/documents/2007-2008/publicact/pdf/2008-PA-0295.pdf

Grid Application Benefit Assessment

The Grid Application Benefit Assessment serves as a glossary of smart grid applications that identifies who benefits from the application and how and why they benefit. This glossary also identifies who may be adversely impacted by the application, how and why they may be impacted, and what the likely regulatory impacts of the application are. The assessment table can be found in Appendix G. A description of each application can be found in Appendix J.

Future Opportunities

Application Prioritization

Utilities in Michigan are at various states of deployment of smart grid and AMI. How utilities deploy smart grid is influenced by what level of priority they place on certain applications. This prioritization is influenced by a host of factors associated with the particular application, such as cost-effectiveness, customer acceptance, and market conditions of other associated technologies.

There were a total of 25 smart grid applications, and each application belonged to one of six categories: AMI applications, customer-oriented applications, demand response, distribution automation, asset/system optimization, and distributed resources. Each individual application was ranked by workgroup stakeholders as being either a high, medium, or low priority.

When the rankings of these applications were examined, it became clear that some applications were unanimously considered to be a high priority for deployment, while other applications did not have such consensus. For example, core AMI functions was ranked as a high priority by all stakeholders, while some applications like customer prepayment and conservation voltage optimization had high and low rankings among stakeholders. Still other applications had high, medium and low priority rankings. While there was not complete consensus on the ranking of all applications, there were some general trends. See Appendix H for a detailed look at the categories, including their individual applications and rankings.

Communications Policy Discussion

There is no one communications technology that is best for all grid communications. It depends on the needs and the specific circumstances of the utility. The goal should be to build a communications network architecture that is integrated, flexible, secure, and built to the extent possible, on open standards. Options include private RF mesh solutions that connect meters via a concentrator; point-to-point (under glass) communications with individual meters using public cellular networks (which also provide the backhaul for mesh networks); PLC; Wi-Fi; and several others. All these decisions need to be based on specific utility application requirements, topologies, and existing installed infrastructure. There is no one-size-fits all.

The characteristics of two particular technologies, common carrier and independent utility communication networks, are particularly pertinent given that they will be used extensively in Michigan.

Characteristics of Common Carriers

- Use of existing cellular networks to send data and commands between smart grid equipment in the field (meters, sensors, control equipment) and a central office for monitoring, processing and control.
- Common carriers offer communication services parallel with other telecommunication and internet services.
- Common carrier networks provide a network that is as ubiquitous, secure and reliable as a utility-owned network.
- A utility using a carrier service is able to deploy distribution automation using related sensors and controls without deployment of AMI or advanced meters.
- The use of common carriers for communications may create an opportunity for joint implementation of AMI that includes all utilities in a geographic area (electric, gas and water).

Characteristics of Independent Utility Communication Networks

- A communication network built, owned and operated by the utility, where meters and other smart grid equipment communicate with each other in order to send and receive data and commands from a central office. These types of networks are commonly known as “mesh networks.”
- Distributed automation applications can be implemented on a standalone basis without AMI deployment in a cost effective manner using a utility-owned network.
- Private networks are secure and reliable. They can fully support partitioning of logical networks for security and bandwidth allocations as well as separate different classes of traffic.

- A utility using an independent utility communications network is able to deploy distribution automation using related sensors and controls without deployment of AMI or advanced meters.
- Owner operated mesh networks can allow a utility to extend its network in areas where common carrier service may be absent.
- An owner operated mesh supports meter capabilities such as remote connect/disconnect, outage reporting, and voltage and power quality measurements.

Plug–In Electric Vehicles

- PEVs represent a particularly interesting smart grid opportunity for Michigan. Much of the electric vehicle design and engineering is being done in Michigan by the traditional "Big 3" automobile manufacturers and their supply chains. Due to past state and federal incentives, Michigan has become the focus of advanced storage system development. The economics of electric vehicle manufacturing appear to favor co-location of battery manufacturing and vehicle assembly. Michigan is becoming a battery manufacturing center; this presents opportunity for the strengthening of the automobile manufacturing industry in and near Michigan. Consequently, PEV integration with the evolving smart grid could be an important economic development opportunity for Michigan and an opportunity for leadership in smart grid technology development and manufacturing. The MPSC should therefore consider the integration of PEVs into Michigan's smart grid evolution as not only a necessary consideration in the evolution of Michigan's electric utilities, but also as an opportunity to contribute to economic development.
- The MPSC could provide opportunity for Michigan's electric utilities to participate in collaborative development of grid integration and smart grid tools for PEVs, along with automobile manufacturers and other suppliers/vendors. Such opportunity should include reasonable recovery of research and development costs.
- When being charged from the grid, a PEV could become a manageable load:
    - Time-varying pricing that appropriately reflects marginal costs of power will usefully guide charging schedules so as to stabilize aggregate loads; this can offer customers lower costs of charging that will encourage electric vehicle adoption and reduce the variability of loads so as to reduce the average cost of power to all electricity customers.

- Systems could be built with dynamic demand capabilities, so that they will reduce load in response to low frequency and thereby increase grid reliability.
- Systems could be developed so that the charging process would participate in dynamic volt/var management.[23]

- There is also the future potential, with a high penetration of PEVs and as stakeholders learn more about battery life and load cycling, that PEVs could serve as round-trip storage systems for electricity, discharging power to the grid or premise in some circumstances. Sometimes referred to as vehicle to grid (V2G) and vehicle to home (V2H), such uses of vehicles could provide benefits similar to those described above for management of the charging process and peak demand reduction. In the short term, V2G communications and demand response implementation programs, rather than V2G power flow, appear to be of the greatest benefit to the customer and the market and are key elements to the design parameters necessary for smart grid development.

Recommendations

Short-Term

- Develop a smart grid vision along with a fair and reasonable regulatory framework for smart grid projects in Michigan. This regulatory framework should protect customers, enable and facilitate utility investment in new technology, and be sustainable over the long-term with minimal need for revisions. Both the vision and the underlying regulatory policies should be structured such that the timing of smart grid investments does not cause excessive burden on customers from the amount of associated upfront capital expenditures, and that investments are timed with consideration toward the implementation of new environmental regulations that may require other significant upfront capital expenditures.
- In order to help quantify costs and benefits associated with certain smart grid applications, guide business case formation, and assist with regulatory review of smart grid proposals, all utilities planning to deploy or currently deploying smart grid technology should consider various pilots across all customer classes. While not all utilities will be able to pilot each of these applications, the pilots should include volt/var control, conservation voltage

[23] Dynamic volt/var management is the use of digital technology to control voltage and reactive power within the distribution system to optimize distribution system performance

optimization, other distribution automation applications, and advanced use of smart meter capabilities including but not limited to:

  - Multiple pricing schemes targeted at assessing demand side energy management behavior.
  - Pricing publication with customer web access and in-premise system access.
  - Meter to in-premise device interoperability.
  - Interval usage metering.
  - Expanded kilovolt Amperage (kVA) power factor metering.
  - Remote meter reading.
  - Accurate and usable billing information based on interval usage and pricing.
  - Remote connect/disconnect.
  - Outage management support.
  - Customer and Customer Authorized third party data access.
  - Reliability and cyber-security will be.

- Once any necessary piloting is concluded, utilities should offer various dynamic pricing programs to applicable customer classes when and where it is cost-effective, beneficial, and accepted by those customers.
- Revise current technical specifications to include advanced meters, specifically addressing: a) hardware defect rates; b) minimum functionality; c) interoperability standards; and d) meter accuracy.

Long-Term

Projecting the future of any technology is difficult, and the smart grid is no different. All stakeholders have provided a list ranking various smart grid applications for future deployment. However, these are only projections. Any number of unforeseen factors could cause a change in ranking and the rationale behind it. In like manner, attempting to articulate a set of long-term recommendations for smart grid deployment in Michigan is equally daunting due to a high level of uncertainty. A set of possible recommendations were proposed by various workgroup stakeholders to address the long-term potential of smart grid in Michigan. Among the ideas and proposals:

- Ensure that all smart grid applications, to the extent they are found cost-effective within the prescribed regulatory framework but respective to each utility, are enabled in all Michigan utilities deploying smart grid by a certain date. This includes those applications associated with distribution automation as well as distributed resources. This recommendation addresses the "implementation" component of the smart grid effort.

- By a certain date in the future, have all Michigan utilities achieve certain performance targets, selecting targets that are smart grid specific. Examples of such targets could include: automatically isolate main line faults and restore unaffected main line portions of the circuit for all main line faults on circuits that have electrical ties to other circuits; reduce greenhouse gas emissions through voltage optimization and distributed resource integration by a specific year; and improve Michigan utilities' generation and distribution efficiency by a percentage to be defined by the stakeholders through voltage optimization and demand response. This recommendation fits into answering the question of "why implement smart grid?"
- Continue moving toward physical completion of distribution system communication channels, emphasizing functions that provide accurate system-wide information, increasing grid stability and improve restoration abilities: AMI, SCADA, and distribution automation (DA). Should be integrated to increase and improve available information.
- The state of Michigan, Michigan electric utilities, automobile manufacturers (presumably including Chrysler, Ford, and General Motors), vehicle charging companies, battery technology companies, US DOE, United States Department of Transportation (US DOT), United States Environmental Protection Agency (US EPA), and all relevant standards groups should create a research and development plan in Michigan for PEV-smart grid integration. This should include charging process responsiveness to time-varying pricing, system frequency responsiveness, and direct load control signals; sub-metering and AMI integration; response to power outage and restoration events; and vehicle battery storage as a distributed resource. The plan would address standards, implementation technologies, user behavior, and analysis of power system effects. Utilities should be allowed to recover their share of the expense of developing such a plan. This recommendation addresses the future role that a smart grid could serve in the automotive industry; an industry that is central to Michigan's economy.

Summary and Conclusions

The Distribution and Grid Applications Workgroup sought to break up the concept of the "smart grid" into individual categories, and within these categories list individual applications and then discuss the benefits and challenges associated with them. Each category of applications has its roots in the present electric grid, with some applications having their origins many decades ago. With the list of applications, the workgroup was then able to catalog the deployment status of each application within three Michigan investor-owned utilities – DTE, CE, and I&M. The status of each application's deployment reflected how high of a priority the utilities placed on putting a certain application into operation. In a general sense, some stakeholders agreed unanimously on what categories of applications should be deployed first, second and so on; however, in terms of individual applications, there was much less consensus in terms of deployment priority. The communications platform aspect of AMI and smart grid was discussed, as was the role of PEVs in the smart grid. The group also researched and discussed the benefits and adverse impacts of each application, what parties benefitted and who would be impacted, and what the likely regulatory impacts of the applications were.

The efforts of the Distribution and Grid Applications Workgroup have produced several conclusions regarding the future of the smart grid in Michigan.

- The "smart grid" is not a single one-shot technology upgrade to the electric grid, but instead is a set of technological applications, with some applications closely related to each other and others not. Moreover, some of this technology is not new, and has been around for decades.
- Not every technology that fits under the smart grid "umbrella" must be deployed at the same time. While some applications should be deployed together for cost-effectiveness, many applications can be deployed at different stages. It is clear that the deployment of smart grid as a whole will occur on a gradual, incremental basis as an evolution, not a revolution.
- There is a wide variety of opinions regarding which smart grid applications should be deployed first, second, and so on, and that this prioritization depends on a multitude of factors, such as cost, magnitude of benefits, customer acceptance, and dependence on market penetration of other associated technologies.
- Each application has costs and impacts as well as benefits, and many of these costs are unquantifiable (as are certain benefits). The relevant question for regulators in particular is whether the benefits outweigh these costs, what "unquantifiable" benefits and costs should be included in a cost-benefit analysis, and how, for those that are to be included, should they be calculated and accounted for.

Generation and Transmission Workgroup Report

Purpose and Focus

An important part in making a road map to where we want to be is to take stock of where we are now. Smart grid technology is expected to enable real-time coordination of information, integrate renewal energy sources and improve the reliability and efficiency of the grid. Acknowledging that “smart” technology has been part of Michigan’s bulk power system for decades, workgroup members pooled their considerable expertise to address the goals contained in the Collaborative proposal:

- Establish the best opportunities and methodologies to achieve improved system efficiency.
- Identify the potential impact of smart grid on generation and the transmission system, including Michigan transmission aspects of smart grid deployment with an eye toward maximum improvements in performance, reliability, system efficiency and the integration of renewable energy.

The future of the smart grid is dependent on long-term planning strategies and integration of all utility partnerships and resources. The smart grid will not just be a method for remote meter reads, but will have an impact on all aspects of utility operation and planning. Smart grid enabled changes such as TOU, DLC, distributed generation; renewable resources and increased customer awareness of energy usage impact not only the local distribution companies, but transmission operators and generation planning as well. The collaboration and integration of transmission and generation companies with the future business plans of the investor-owned utilities will allow for appropriate future growth.

The focus of this workgroup has been to bring all of these partners, such as MISO, transmission companies (ATC, ITC and METC, the latter two referred to as the ITC and WPSI), investor owned utilities (CE, DTE and I&M) and the MPSC together to develop an understanding of the potential of the smart grid. Only through open communication, planning and joint collaboration can the smart grid succeed.

Historical Perspective

- Prior to MISO energy market start on April 1, 2005:

- FERC issued orders 888 and 889 that established rules to open the nation's wholesale bulk electric system to competition in 1996. This led to the formation of MISO. In December 2001, FERC approved MISO as the nation's first Regional Transmission Organization (RTO), providing reliability coordination and regional planning services.
- Generation to meet Michigan demand was dispatched on a schedule determined by the local balancing authorities – CE and DTE. Generation was dispatched by the utilities utilizing owned units and third party resources.
- Balancing the system (matching generation to load) was decentralized and done on a local level.

- From energy market start on April 1, 2005, to the ASM start on January 6, 2009:
  - A centralized dispatch was performed by MISO across the entire footprint based on a market clearing price.
  - MISO assumed responsibility for energy imbalance across the transmission system.
  - CE and DTE retained the role of balancing the system and provided ancillary services (regulating reserve, spinning reserve and supplemental reserve).
- After the ASM start on January 6, 2009:
  - MISO provided ancillary services (regulating reserve, spinning reserve and supplemental reserve).

Market Dispatch

Since 2005, the utilities' generating units have been effectively dispatched by MISO under federal supervision. The manner in which MISO dispatches generators is much the same as the manner in which the utilities dispatched their generating units for the 30 years preceding MISO when the utilities participated in the Michigan Electric Coordinated Power Pool under state jurisdiction. The utilities' strategies for determining economic dispatch parameters have remained unchanged. The compensation that they receive when their generation is dispatched above its load is used to offset the utility Power Supply Cost Recovery (PSCR) expenses. Over 1,200 generators make offers to operate in the day-ahead energy and ASM for every hour of the year. Additionally, those same generators are physically dispatched by MISO and provide bids and offers to increase or reduce their production in the real-time energy and ASM for every 5-minute period of the year.

Market Transformation

Since the launch of ASM in January 2009, MISO has evolved the markets to allow demand response to participate in the energy and ASM on a comparable basis as generation. A regulation product for storage was also implemented that provided grid level storage facilities, a product specialized for their operating characteristics. Stakeholder discussions are currently underway to address the impact of dynamic retail rates on load curves, particularly for load peaks.

Current Deployment Status in the Bulk Power System

MISO, the transmission system operators and the two primary generator/distribution owners submitted inventories of their current deployment of smart grid technologies. Those inventories are contained in Appendix I.

Future Technologies in the Bulk Electric System

Cyber Security

Cyber security is an important consideration both now and in the future of the electric grid. Nationally, groups are engaged in dialogs to make sure the grid becomes increasingly reliable, without becoming more vulnerable.

With the smart grid's transformation of the electric system to a two-way flow of electricity and information, the information technology and telecommunications infrastructures have become critical to the energy sector infrastructure. The management and protection of systems and components of these infrastructures must also be addressed by an increasingly diverse energy sector. To achieve this, it requires that security be designed at the architectural level.

NERC-CIP standards have altered the way a utility adapts new technology and updates existing technology. With a clear emphasis on security, these standards have defined the operation, reporting, and maintenance of critical cyber assets very precisely. Software or firmware updates must be fully tested, verified, and documented. New technology must fully comply with all standards, especially if it is integrated with networking technology. New procedures and documentation are also required by many Critical Infrastructure Protection (CIP) standards. While labor intensive on the front end, proper documentation is essential to the appropriate maintenance and reliability of a smart grid.

Review of an entire system and its assets is also mandatory; prompting utilities to clearly identify assets and stations as critical.

NIST has established a smart grid CSCTG, which has more than 200 volunteer members from the public and private sectors, academia, regulatory organizations and federal agencies. Cyber security is being addressed in a complementary and integral process that will result in a comprehensive set of cyber security requirements. These requirements are being developed using a high-level risk assessment process that is defined in the cyber security strategy for the smart grid. Cyber security requirements are implicitly recognized as critical in all of the particular priority application plans.

NIST published the Smart Grid Cyber Security Strategy and Requirements (NISTR 7628) that describes the CSCTG's overall cyber security strategy for the smart grid. The preliminary report distills use cases collected to date, requirements and vulnerability classes identified in other relevant cyber security assessments and scoping documents, and other information necessary for specifying and tailoring security requirements to provide adequate protection for the smart grid. Electric Power Research Institute (EPRI), along with members such as DTE and CE, are developing a user implementation guide for NISTIR 7628. This guide will be used for Michigan utilities and transmission providers to implement NISTIR 7628 cyber security best practices into grid control and communication systems.

NERC-CIP standards require annual reviews and promote constant considerations of network security. One major operational change is the necessary intervention of Information Technology (IT) services in many areas of system design and communication. IT professionals are required to configure telecommunications on-site and at control centers to ensure proper access control and security. As utilities move to smart grid technologies, they must be ever prescient of the CIP standards and how they relate to each evolving technology. In the end, the CIP standards will foster a smarter and more secure grid.

Pilots and Demonstration Projects

ATC Pilot Project: Managing Flows Across Michigan's Upper Peninsula

Background

The transmission system in the Upper Peninsula of Michigan (UP) is significantly impacted by external influences, including the Ludington generation plant in NW Michigan, as well as generation shifts in the upper Midwest. The significant addition of wind generation in Iowa and Minnesota and the abundance of hydro-generated power in Canada have also resulted in an increased system bias from the upper Midwest to the central and east central United States, which impacts the operation of the UP system. ATC needed to implement a solution to help manage these flows both from west to east and east to west, within the limits of the existing UP and Lower Peninsula of Michigan (LP) systems. The solutions examined also had to help manage voltages in the UP, including low voltages observed at moderate to high flow and high voltages during very low flow conditions. The systems also had to work well with the UP system, which is saturated with capacitor banks and has no dynamic Var sources. Lastly, the connection between the UP and LP consists of submarine cables which have a high sensitivity to voltage changes and sudden load changes which had to be considered.

ATC Proposed Project

After reviewing options available, ATC recommended the addition of a back-to-back High Voltage Direct Current (HVDC) device with voltage source converter technology to be located in the eastern UP. The proposed back-to-back direct current installation:

- Splits the UP from the LP so that there is no direct AC path between the systems. This allows MISO operations to dispatch flows as needed for system reliability.
- Provides two Static Synchronous Compensator (STATCOM) devices, one at each converter/inverter that provides a badly needed dynamic Var source for the UP.
- Integrates well with existing submarine cables as it provides smooth MW ramping versus discreet steps provide by a phase shifter.

Benefits of Proposed Project

If approved and implemented, the equipment will provide robust and smooth MW flow control to help keep the UP system intact, allow scheduling of maintenance and construction outages more easily in the UP and northern lower Michigan, manage system flows across a full range of hourly and real-time system conditions, and accommodate future local and regional generation and load profile changes. It will provide robust voltage control with dynamic real power capabilities to both the UP and LP. It will also provide frequency control/black start functionality during extreme events. It will allow energizing of a non-operative transmission line that will reduce system losses and improve voltage profiles, complimenting the flow control device.

ITC Holdings Transmission Smart Grid Investments

To date, ITC's smart grid investments have focused on improving the reliability, security, and functionality of the transmission system. ITC's strategy has leveraged both the communications capability of the existing communications network and a strategic view of the types of data required to improve operation and analysis of the system. Years of planning were dedicated to ensuring that ITC could integrate security and communication needs into a robust data network with flexibility for upgrades in the future.

ITC uses an industry standard protocol, Distributed Network Protocol 3 (DNP 3) for all SCADA data communication. Global positioning system (GPS) clocks are used in each substation to ensure that all data is time stamped with the same accurate time. This ensures that events around the system are easy to analyze and the events are reliable. This data is also used with a lightening tracking system to assist with fault analysis after system events have occurred. These times are then checked against a database of known lightning activity to see if any correlation can be made between lightning strikes and the system events.

With high bandwidth communication and accurate GPS time available, ITC is capable of very advanced monitoring. ITC is collaborating with MISO to deploy eight phasor measurement units (PMU) by the end of 2011. The primary goal of the MISO synchrophasor project is to establish synchrophasor infrastructure and data integration for planning and operational processes.

ITC also employs transformer monitors to protect transmission system transformers by collecting data, establishing conditional thresholds and sending alerts to engineering staff for further analysis. The data collected includes dissolved gas in oil analysis, power factor bushing monitor, full range of temperatures, current status of fans and pumps, active cooling control, and traditional fans and pumps.

ITC will continue to upgrade the transmission system with appropriate smart grid technologies as their value to the operation of the grid is proven. This approach ensures that ITC will retain interoperability with various smart grid applications as they are deployed.

Recommendations

As mentioned earlier in this report, the members of the Generation and Transmission Workgroup believe the realization of smart grid's promise depends upon long-term planning strategies with the integration of all utility partnerships and resources in this process.

The applicability of the following recommendations should not be interpreted as being limited only to the Generation and Transmission section of this report. Generation and transmission is only one piece of smart grid. The usefulness of these suggestions cross workgroup lines and contribute to a cohesive, collaborative approach to this all-encompassing concept known as smart grid. (Unless otherwise noted, the following statements may be considered a consensus position of the workgroup.)

MISO

- Identify specific opportunities within the MISO market structure to reduce system costs and increase reliability, e.g., higher frequency dispatch.
- Conduct a cost benefit study of real-time market monitoring to determine if the capital outlay necessary to receive and analyze data continuously (rather than the current 15 minute model), will be justified by identification of market design flaws that create inefficient or perverse incentives.

Transmission Operators

- Coordination and cooperation with MISO and NASPI.
- Work closely with MISO on their synchrophasor implementation project to provide data and to help develop applications that use the data.
- Work closely with the NASPI group to stay current on developments nationally and world-wide.
- Improve reliability by continuing to install new advanced transmission system protection systems and advanced intelligent electronic devices.

- Improve visibility and security of the transmission system by upgrading telecommunication infrastructure and monitoring capabilities.

MPSC

- Research and author white papers of interest to Commissioners.
- Review the pros and cons of different generation sources including the integration of renewable energy sources.
- Consider distributed generation options including the impact of small scale solar and wind.
- Target areas of greatest benefit to utilities and other stakeholders, including the impact of renewable energy sources and demand response initiatives.
- Evaluate cost benefit considering impact on transmission and generation operators, customers and other stakeholders.

General

- Coordinate yearly update of the smart grid technology deployment inventory, with updates from transmission operators and utilities.
- Analyze and develop long-term implementation strategy for the state.
    - Develop a strategic plan to optimize devices to the greatest advantage/lowest cost.
- Upgrade equipment and practices to continue improving reliability and system visibility. Continually analyze new technology for best practices.
- Gain efficiency in dealing with unplanned outages using appropriate reliability indices such as Loss of Load Probability (LOLP), Loss of Load Expectation (LOLE), Loss of Load Frequency (LOLF) and Expected Unserved Energy (EUE).

Summary and Conclusions

Michigan companies have deployed a fair amount of smart grid resources with more planned for the future. As these technologies gain acceptance, we will need to evaluate the impacts of these technologies on generation and transmission in the state. Future discussion and cooperation is needed for the best outcome for smart grid deployment on the transmission side of the industry in Michigan.

Codes and Standards Workgroup Report

Purpose and Focus

An often overlooked trait of our modern electrical grid is the commonality of all of the components. Across the United States, the hardware and software devices are built upon a backbone of standards that allow the consumer to move anywhere in the country or state and seamlessly plug-in their electrical devices. The future vision of the modernized grid includes secure and seamless connectivity for devices capable of communicating within the grid. The state of Michigan is participating in the realization of this vision through efforts directed by the EISA legislation, along with many other industry consortium groups and Standards Development Organizations (SDOs).

As we look to update the electrical grid into the smart grid, it is important that we achieve a grid that is interoperable. A grid that is built upon nationally accepted codes and standards will allow better economies of scale, increased security, and promote best practices.

The Codes and Standards Workgroup drew from their experienced leadership to address the following goals laid out in the smart grid Collaborative proposal:

- Foster utility and MPSC participation and input to influence the impact of national efforts designed to promote adoption of smart grid interoperability standards. These efforts include, but are not limited to, the DOE, Gridwise Architecture Council (GWAC), FERC, NIST, and/or SDOs.
- Proactively influence the national and state direction and adoption of smart grid consumer privacy-enabling technology standards and cyber security.
- Provide a roadmap for the use of smart grid interoperability standards to minimize the risk of stranded costs for legacy equipment and early life obsolescence for new smart grid equipment.
- Establish reference documentation that explains smart grid technologies, conceptual models and interoperability standards.

Historical Perspective

Support for development of the smart grid in the United States gained impetus from Title XIII of EISA. The development of the smart grid was identified by EISA as a national policy goal. Incentive for standards development increased as the ARRA of 2009 provided the US DOE with $4.5 billion to invest in smart grid investment and demonstration grants. The ARRA funds greatly accelerated the development and implementation of smart grid technologies and interoperability standards.

EISA assigned NIST the task of coordinating the development of a framework of information management protocols and standards that will achieve smart grid device and systems interoperability. NIST responded to its EISA mandate by developing and implementing a plan to identify an initial set of standards, to establish a framework to sustain the development of additional standards that will be needed, and to set up an infrastructure for conformity testing and certification. The NIST plan incorporated three phases.

The first phase of NIST's plan entailed public workshops that occurred in April, May and August of 2009. The NIST Framework and Roadmap for Smart Grid Interoperability Standards Release 1.0 documented the efforts of these workshops and other outreach efforts made by the Office of the National Coordinator for Smart Grid Interoperability. This framework document included a high-level conceptual reference model for the smart grid, identified 75 existing standards applicable to smart grid development, identified 16 areas where new or revised standards would be needed for smart grid implementation, and described a strategy to address cyber security of the developing smart grid. The first phase of the NIST plan culminated in the release of the framework document in January 2010. This phase of NIST's plan also saw the establishment the first 16 PAPs to address those areas identified as needing further standards development.

The second phase of the NIST plan, initiated in November 2009, was the establishment of the SGIP. SGIP was created by NIST to be an ongoing public-private partnership organization and consensus process to provide structured support for a continuous evolution of the smart grid standards framework. There are currently nearly 700 member organizations in the SGIP. They are divided among 22 stakeholder categories. The 16 PAPs initiated in the first phase of NIST's plan were subsequently incorporated into the SGIP and another three PAPs have been initiated. (A current list of the PAPs is provided below.)

PAP	Title/Description
PAP 00	Meter Upgradeability Standard
PAP 01	Role of Internet Protocol in the Smart Grid
PAP 02	Wireless Communications for the Smart Grid
PAP 03	Common Price Communication Model
PAP 04	Common Scheduling Mechanism
PAP 05	Standard Meter Data Profiles
PAP 06	Common Semantic Model for Meter Data Tables
PAP 07	Electric Storage Interconnection Guidelines
PAP 08	CIM for Distribution Grid Management
PAP 09	Standard DR and DER Signals
PAP 10	Standard Energy Usage Information
PAP 11	Common Object Models for Electric Transportation
PAP 12	IEC 61850 Objects/DNP3 Mapping
PAP 13	Time Synchronization, IEC 61850 Objects/IEEE C37.118 Harmonization
PAP 14	Transmission and Distribution Power Systems Model Mapping
PAP 15	Harmonize Power Line Carrier Standards for Appliance Communications in the Home
PAP 16	Wind Plant Communications
PAP 17	Facility Smart Grid Information Standard
PAP 18	SEP 1.x to SEP 2 Transition and Coexistence

Note: current status of the PAPs can be found at http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/PriorityActionPlans

SGIP's primary role is to define requirements for essential communication protocols and other common specifications and coordinate development of these standards by SDOs or Standards Setting Organizations (SSOs). SDOs or SSOs are established organizations that develop and maintain standards through open, balanced and collaborative processes. They include the following organizations, but are not limited to those shown below:

SDO/SSO	Full Name
3GPP	Third Generation Partnership Project
AEIC	Association of Edison Illuminating Companies
ANSI	American National Standards Institute
ASHRAE	American Society of Heating, Refrigerating & Air Conditioning Engineers
CEA	Consumer Electronics Association
ETSI	European Telecommunications Standards Institute
HomePlug	HomePlug Powerline Alliance
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
IETF	Internet Engineering Task Force
ISA	International Society of Automation
ISO	International Organization for Standardization
ITU	International Telecommunications Union
MultiSpeak	MultiSpeak Specification
NAESB	North American Energy Standards Board
NEC	National Electric Code
NEMA	National Electrical Manufacturers Association
NERC	North American Electric Reliability Corporation
OASIS	Organization for the Advancement of Structured Information Standards
SAE	Society of Automotive Engineers
TIA	Telecommunications Industry Association
W3C	World Wide Web Consortium
WI-FI	WI-FI Alliance
ZigBee	ZigBee Alliance

These organizations are responsible for the actual development and publication of formal standards. SGIP has engaged many SDOs to take input in the form of requirements for smart grid functionality and interoperability and to utilize this input to revise existing standards or develop new standards. When the new and revised standards are completed and SGIP has assured that they satisfy the submitted requirements, they are vetted through established SGIP voting and consensus processes for inclusion in the SGIP catalog of standards. This catalog can then be used by energy providers and others to develop select and implement smart grid technologies, protocols and devices.

In addition to SGIP, several other consortiums and user groups participate and contribute to the work of the SGIP and the PAPs. Most of these pre-date the formation of the SGIP, but have significantly collaborated with both the SGIP and the SDOs.

OpenSG, a technical consortium organized within the Utility Communication Architecture International users group (UCAIug), consists of several technical working groups that help formulate and articulate requirements that the various SGIP PAPs and working groups consolidate and communicate to the SDOs. The GridWise Architecture Council (GWAC) has been instrumental in defining overall smart grid conceptual modeling that has given high level structural guidance to the work of the SGIP. The Edison Electric Institute (EEI) and EPRI, as utility industry consortiums, have been important in contributing perspectives of the electric utility industry. Other forums, including the GridWise Alliance, NARUC, the Internet Engineering Task Force, the ZigBee Alliance, HomePlug Powerline Alliance, and many others have also been important contributors to the SGIP and the standards processes.

The third phase of the NIST plan is to provide a framework for conformity testing and certification of smart grid devices and systems. This phase of the plan is currently being led by the SGIP's Smart Grid Testing and Conformity Committee.

Current Deployment Status of Applications/Standards

The public utilities within the state of Michigan, (I&M, CE and DTE) and the MPSC have been actively involved in the smart grid interoperability standards effort since 2009. They are all active members of SGIP and provide direct input and leadership into many of the standards development efforts. As an example, all the Michigan utilities are active members of several OpenSG groups and the OpenSG Technical Committee. As noted previously, OpenSG is a technical consortium group that has been very instrumental in the definition of use cases and requirements for future interoperability standards.

While the identification and development of interoperability is a priority for the Collaborative, it should be noted that voluntary adoption versus mandated adoption is critical to the marketplace. The voluntary nature of standards is important in order to encourage innovation, avoid unnecessary implementation costs, avoid negative reliability impacts and avoid premature legacy equipment obsolescence. In a recent ruling on the smart grid standards Docket RM11-2, FERC supported this concept and encouraged utilities, manufacturers, regulators and other stakeholders to actively participate in the NIST interoperability framework process and refer to that process for guidance on standards. The Collaborative was encouraged by the FERC order and it was viewed as a positive step which supports the work underway by the industry and NIST to develop voluntary interoperability standards.

Cyber security and data privacy continue to be an area of priority for interoperability standards development. Security of the bulk power system is a primary concern at the national level. FERC has jurisdiction over the bulk power and transmission systems. FERC has enacted rulemaking to ensure compliance with reliability and cyber security standards such as NERC-CIP standards. As electric distribution level systems become more automated and interconnected, the risk of a large aggregated load impact becomes greater. In addition, communication networks implemented for smart grid systems may leverage public wireless systems that are exposed to untrusted networks. These new vulnerabilities need to be considered during the evolution of interoperability standards. The Codes and Standards Workgroup is actively monitoring and participating in cyber security related standards forum.

The Codes and Standards Workgroup performed a thorough analysis of smart grid use cases and concepts in order to determine alignment of technology standards and strategies and identify with gaps. This process mapped use cases/functions to specific domains, identified requirements specifications, and standards specifications for each of the identified functions. For reference, the SGIP Conceptual Model was consulted.

Smart Grid Conceptual Model

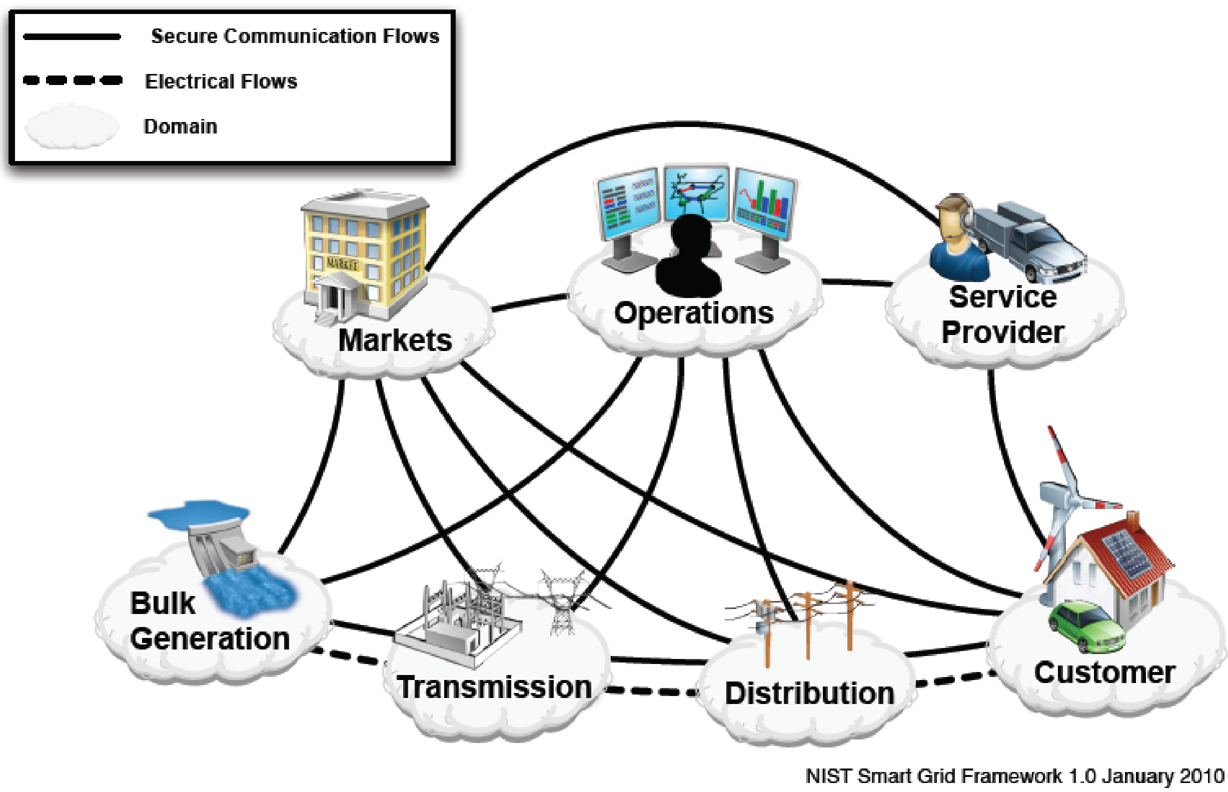


Figure 1

http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/SGConceptualModel

Customer Domain

The customer is ultimately the stakeholder that the entire grid was created to support. This is the domain where electricity is consumed. Actors in the customer domain enable customers to manage their energy usage and generation. Some actors also provide control and information flow between the customer and the other domains. The boundaries of the customer domain are typically considered to be the utility meter and the Energy Services Interface (ESI). The ESI provides a secure interface for utility to consumer interactions. The ESI in turn can act as a bridge to facility-based systems such as a Building Automation System or a customer's Energy Management System (EMS).

Customer

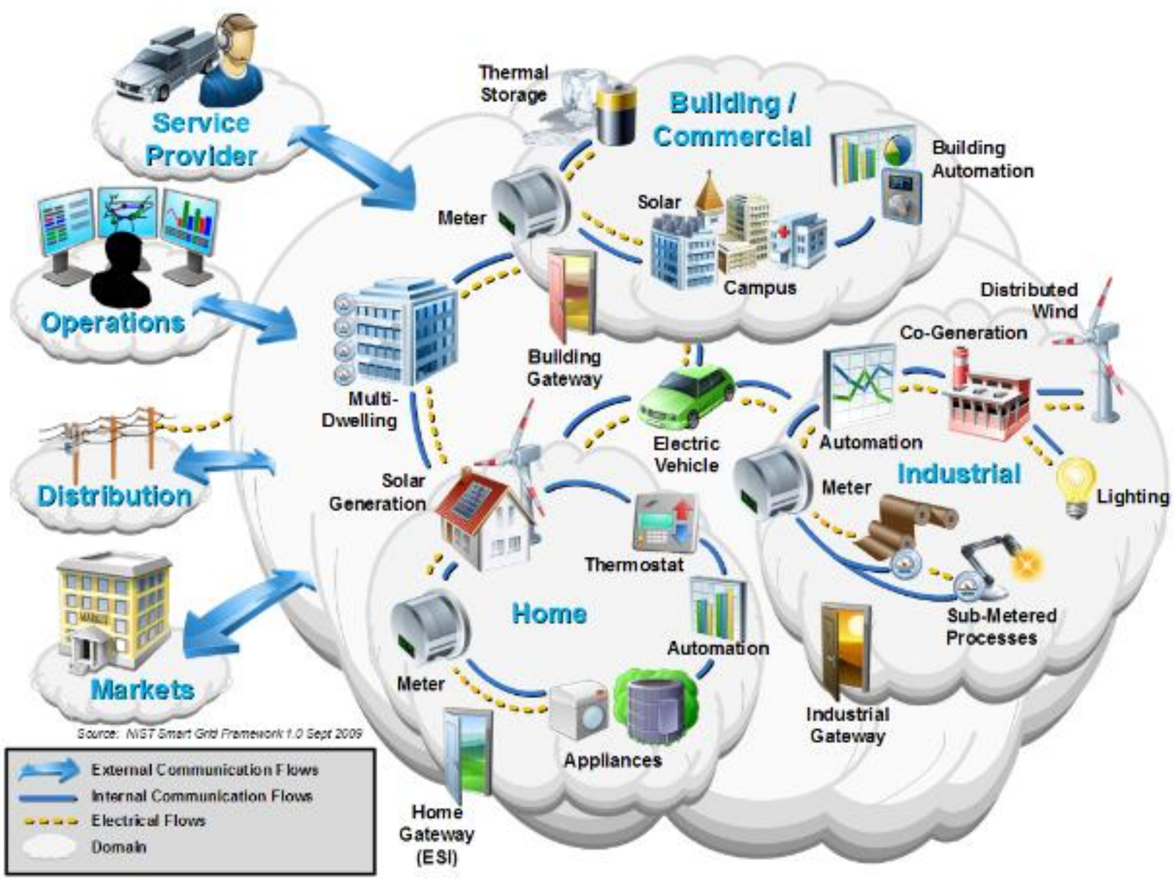


Figure 2 http://collaborate.nist.gov/twikisggrid/bin/view/SmartGrid/IKBDomains#Customer_Domain

Markets Domain

The markets are where grid assets are bought and sold. Actors in the markets domain exchange price and balance supply and demand within the power system. The boundaries of the markets domain include the edge of the operations domain where control happens, the supply assets (e.g., generation, transmission, etc.) and the customer domain.

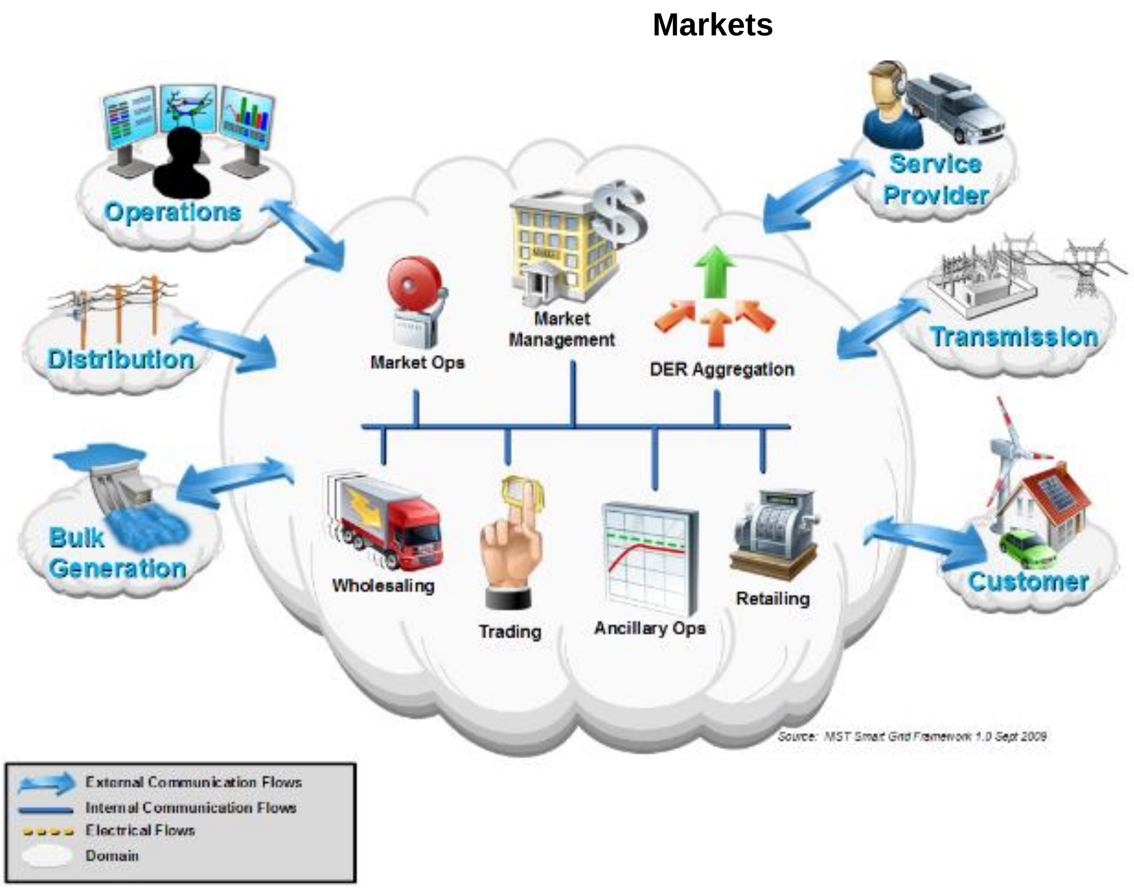


Figure 3 http://collaborate.nist.gov/twikisggrid/bin/view/SmartGrid/IKBDomains#Markets_Domain

Service Provider Domain

Actors in the service provider domain perform services to support the business processes of power system producers, distributors and customers. These business processes range from traditional utility services such as billing and customer account management to enhanced customer services such as management of energy use and home energy generation. The service provider must not compromise the cyber security, reliability, stability, integrity and safety of the electrical power network when delivering existing or emerging services.

Service Provider

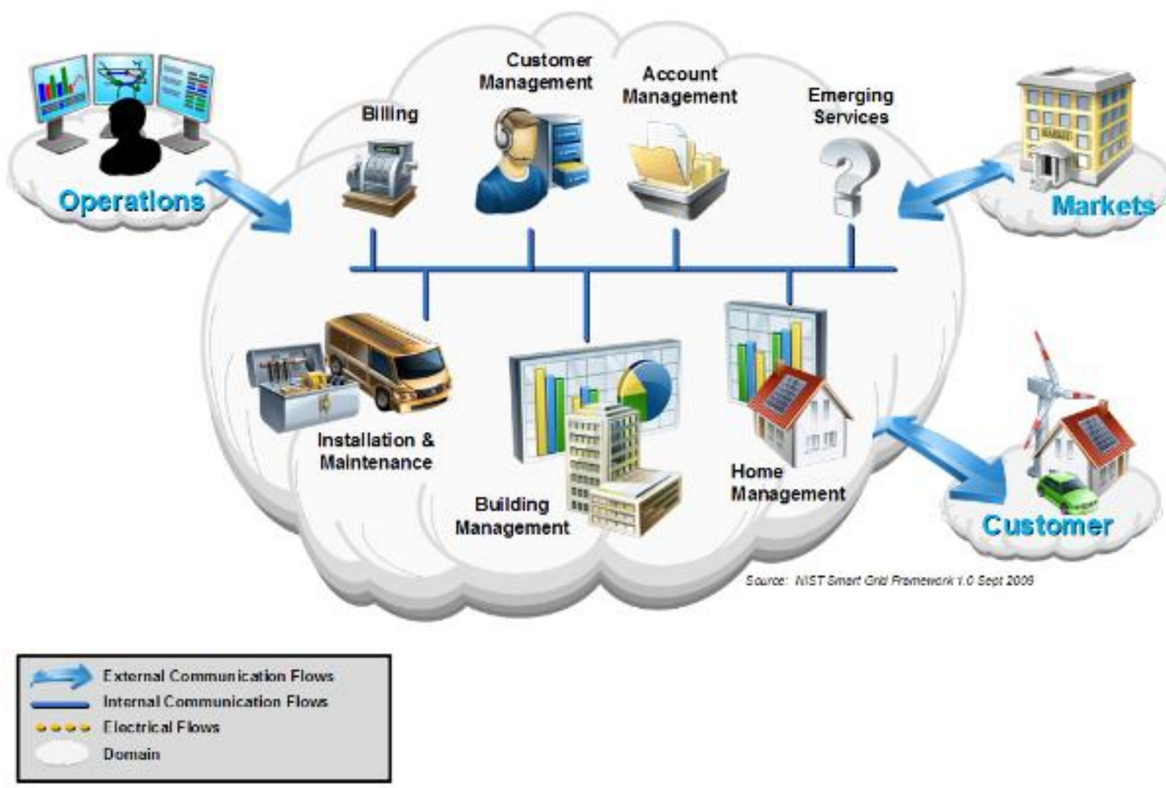


Figure 4

http://collaborate.nist.gov/twikisggrid/bin/view/SmartGrid/IKBDomains#Service_Provider_Domain

Operations Domain

Actors in the operations domain are responsible for the smooth operation of the power system. Today, the majority of these functions are the responsibility of a regulated utility. The smart grid will enable more of them to be outsourced to service providers; others may evolve over time. No matter how the service provider and markets domains evolve, there will still be basic functions needed for planning and operating the service delivery points of a "wires" company.

In transmission operations, EMS are used to analyze and operate the transmission power system reliably and efficiently, while in distribution operations, similar Distribution Management System (DMS) are used for analyzing and operating the distribution system.

Operations

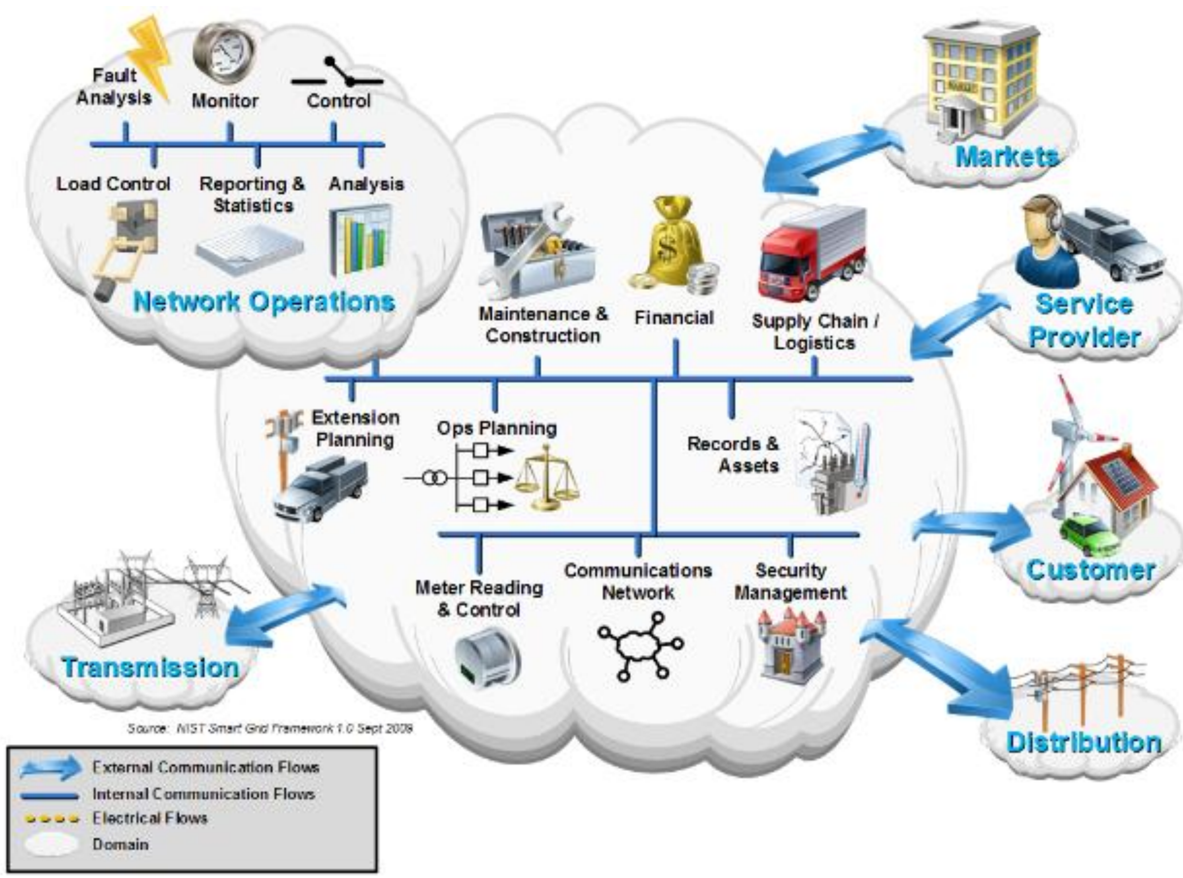


Figure 5 http://collaborate.nist.gov/twikisggrid/bin/view/SmartGrid/IKBDomains#Operations_Domain

Bulk Generation

Applications in the bulk generation domain are the first processes in the delivery of electricity to customers. Electricity generation is the process of creating electricity from other forms of energy, which may vary from chemical combustion to nuclear fission, flowing water, wind, solar radiation and geothermal heat. The boundary of the generation domain is typically the transmission domain.

The bulk generation domain is electrically connected to the transmission domain and shares interfaces with the operations, markets and transmission domains.

Communications with the transmission domain are the most critical because without transmission, customers cannot be served. The bulk generation domain must communicate key performance and quality of service issues such as scarcity (especially for wind and sun) and generator failure. These communications may cause the routing of electricity onto the transmission system from other sources. A lack of sufficient supply may be addressed directly (via operations) or indirectly (via markets).

New requirements for the bulk generation domain include greenhouse gas emissions controls, increases in renewable energy sources and provision of storage to manage the variability of renewable generation.

Actors in the bulk generation domain may include various devices such as protection relays, remote terminal units, equipment monitors, fault recorders, user interfaces and programmable logic controllers.

Bulk Generation

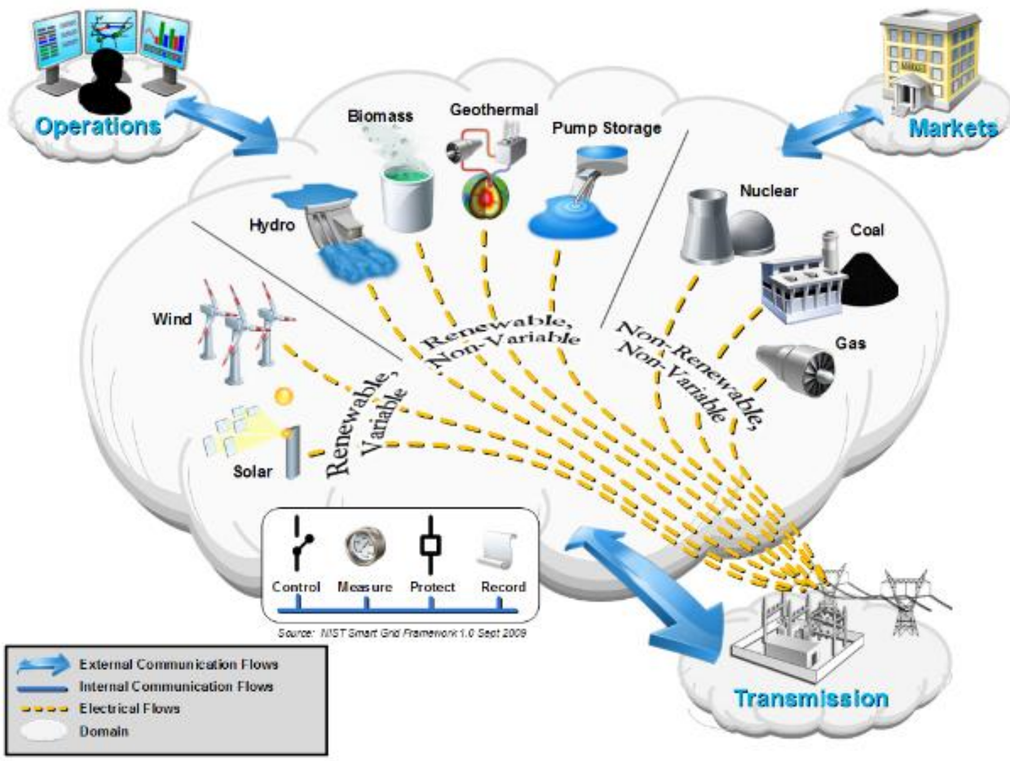


Figure 6

http://collaborate.nist.gov/twikisggrid/bin/view/SmartGrid/IKBDomains#Bulk_Generation_Domain

Appendix A

Transmission Domain

Transmission is the bulk transfer of electrical power from generation sources to distribution through multiple substations. A transmission network is typically operated by a Regional Transmission Operator or Independent System Operator whose primary responsibility is to maintain stability on the electric grid by balancing generation (supply) with load (demand) across the transmission network.

Examples of actors in the transmission domain include remote terminal units, substation meters, protection relays, power quality monitors, phasor measurement units, sag monitors, fault recorders, and substation user interfaces. The transmission domain may contain distributed energy resources such as electrical storage or peaking generation units. Energy and supporting ancillary services (capacity that can be dispatched when needed to stabilize the grid) are procured through the markets domain and scheduled and operated from the operations domain, and finally delivered through the transmission domain to the distribution system and finally to the customer domain.

Most activity in the transmission domain is in a substation. An electrical substation uses transformers to change voltage from high to low or the reverse across the electric supply chain. Substations also contain switching, protection and control equipment. The figure depicts both step-up and step-down substations connecting generation (including peaking units) and storage with distribution. Substations may also connect two or more transmission lines. Transmission towers, power lines and field telemetry such as the line sag detector shown make up the balance of the transmission network infrastructure. The transmission network is typically monitored and controlled through a SCADA system composed of a communication network, monitoring devices and control devices.

Transmission

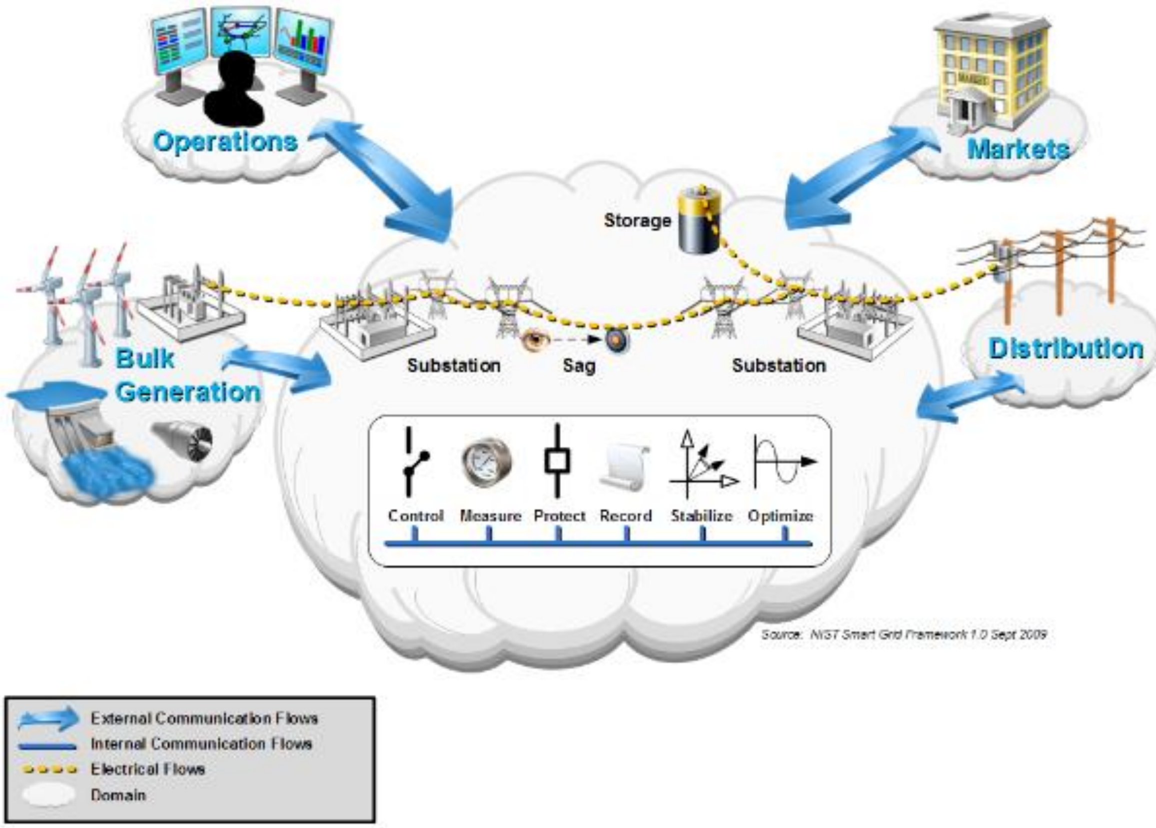


Figure 7 http://collaborate.nist.gov/twikisggrid/bin/view/SmartGrid/IKBDomains#Transmission_Domain

Distribution Domain

The distribution domain is the electrical interconnection between the transmission domain, the customer domain and the metering points for consumption, distributed storage, and distributed generation. The electrical distribution system may be arranged in a variety of structures, including radial, looped or meshed.

The reliability of the distribution system varies depending on its structure, the types of actors that are deployed, and the degree to which they communicate with each other and with the actors in other domains. Historically, distribution systems have been radial configurations, with little telemetry, and almost all communications within the domain was performed by humans. The primary installed sensor base in this domain is the customer with a telephone, whose call initiates the dispatch of a field crew to restore power.

Historically, many communications interfaces within this domain were hierarchical and unidirectional, although they now generally can be considered to work in both directions, even as the electrical connections are beginning to do. Distribution actors may have local inter-device (peer-to-peer) communication or a more centralized communication methodology.

In the smart grid, the distribution domain will communicate more closely with the operations domain in real-time to manage the power flows associated with a more dynamic markets domain and other environmental and security-based factors. The markets domain will communicate with distribution in ways that will effect localized consumption and generation. In turn, these behavioral changes due to market forces may have electrical and structural impacts on the distribution domain and the larger grid. Under some models, other entities may communicate with the customer domain using the infrastructure of the distribution domain; such a change would affect the communications infrastructure selected for use within the domain.

Distribution

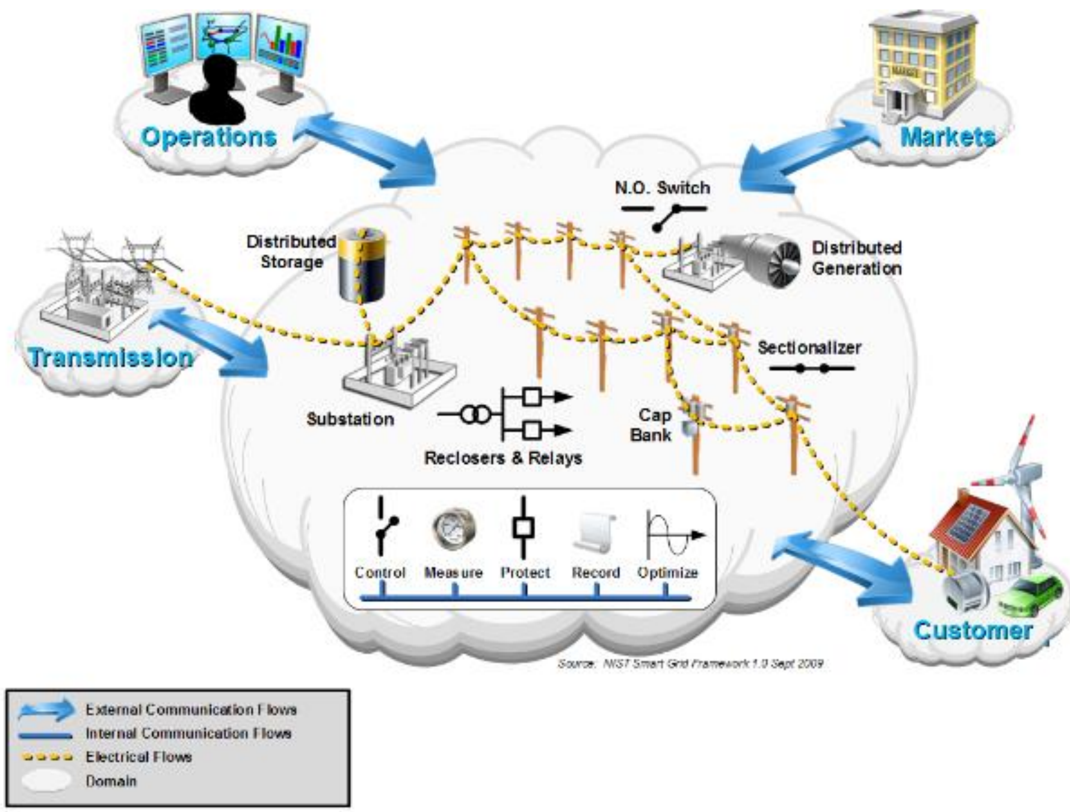


Figure 8

http://collaborate.nist.gov/twikisggrid/bin/view/SmartGrid/IKBDomains#Distribution_Domain

Codes and Standards Roadmap

The Codes and Standards Workgroup collectively developed a list of smart grid interoperability standards which are relevant to implementations within Michigan. The following smart grid applications were used as a starting point for mapping applicable requirements and standards. The smart grid applications are organized into seven areas as noted below:

1. AMI Applications
    a. Core AMI functions
    b. Remote connect/disconnect
    c. Outage management support
    d. Power quality/voltage monitoring at the meter
    e. Customer prepayment utilizing AMI
2. Customer-Oriented Applications

    a. In-premises devices for energy usage data
    b. Outage notification to customer
    c. Sharing of customer data
3. Demand Response
    a. Pricing information to in-premise devices
    b. Direct load control
    c. System frequency signal to customer load control devices
    d. Systems renewable output to customers
4. Distribution Automation
    a. Automatic circuit reconfiguration
    b. Improved fault location
    c. Dynamic system protection for two-way power flows and distributed resources
    d. Dynamic volt/var (volt-ampere reactive) management
    e. Conservation voltage optimization
5. Asset System Optimization
    a. Enhanced system modeling and planning
    b. Asset sizing optimization
    c. Asset condition monitoring
6. Distributed Resources
    a. Customer distributed resource integration
    b. Coordinated management of distributed resources
    c. PEVs: optimized charging
    d. Dispatch of PEVs storage
7. Transmission
    a. Wide area (phasor) measurement

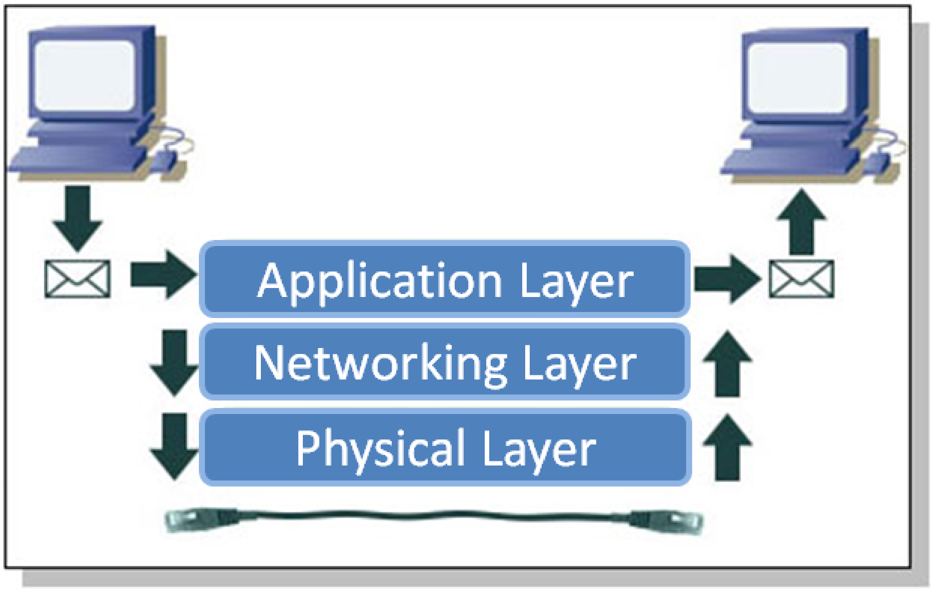
The following table is a brief summary of the conceptual model domain areas previously detailed in this section and used within the list of application standards.[24]

	Domain	Actors in the Domain
1	Customer	The end users of electricity. May also generate, store, and manage the use of energy. Traditionally, three customer types are discussed, each with its own domain: residential, commercial, and industrial.
2	Markets	The operators and participants in electricity markets.
3	Service Provider	The organizations providing services to electrical customers and utilities.
4	Operations	The managers of the movement of electricity.
5	Bulk Generation	The generators of electricity in bulk quantities. May also store energy for later distribution.
6	Transmission	The carriers of bulk electricity over long distances. May also store and generate electricity.
7	Distribution	The distributors of electricity to and from customers. May also store and generate electricity.

[24] Draft NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 2.0

Layered Approach Overview

The Codes and Standards Workgroup used a layered approach when evaluating applicable standards to the applications. The layers are called physical, networking and application. The illustration below describes how this approach works using email as an example.



The physical layer represents the physical and medium access control layer as defined within the Internet Engineering Task Force (IETF). Examples of this layer include, but are not limited to, Wi-Fi (IEEE 802.11), Code Division Multiple Access (CDMA), Global System for Mobile Communications (GSM), etc. The networking layer represents the network layer and the transport layer as defined within the IETF. Examples of this layer include IPv4, IPv6, 6LoWPan, etc. The application layer represents the application layer as defined within the IETF. Examples of this layer include HTTP, ANSI C12 family, etc. The layered approach is best described by the IETF document found at: http://tools.ietf.org/html/rfc1122

Requirements and Standards Sources

The Codes and Standards Workkgroup referenced the NIST Framework Version 1.0 and 2.0 along with output from SGIP DAPs in order to form a base line of applicable requirements and standards.

The framework documents can be found at:
http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/IKBFramework
The PAPs can be found at:
http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/PriorityActionPlans

Mapping of Applicable Requirements and Standards to Applications

The following sections are the artifacts of the Codes and Standards Workgroup's mapping of applicable standards and requirements to the smart grid application described above. Requirements are a list of desired performance, behavior and personality characteristics various groups in the smart grid industry defined to help standards setting organizations develop standards.

The Codes and Standards Workgroup identified the most applicable and pertinent sets of requirements per smart grid application by domain and layer. Next, the workgroup assigned the appropriate and applicable standard(s) to the application by layer. Standards are specifications for how to implement a technical process, application, and/or function governed by a set of requirements.

Core AMI

AMI metering allows the utility to establish a two-way connection to the premises metering device and supports time differentiated interval measurement. These new measurement capabilities allow for new rate structures and can support increased customer awareness of energy usage. Data from AMI meters can be used by the utility to support other smart grid applications. AMI meters can optionally include a customer owned network interface to support demand response applications and increased customer awareness of energy usage, prices and other information. Table is in Appendix L.

Remote Connect/Disconnect

Remote connect/disconnect devices whether located in AMI meters or as a separate device are equipped with remotely operable integrated service switches. The utility can open or close the switch by sending a signal to the device. The utility may operate the switch for purposes of customer request, pre-payment services, non-payment, safety or reconnection after payment is received. Table is in Appendix L.

Outage Management Support

AMI Meters can report power outage and power restoration messages to the utility. This functionality will allow the utility to determine the scope and location of an outage, to improve outage response time, and to verify that all customer outages are restored. Table is in Appendix L.

Power Quality/Voltage Monitoring at Meter

AMI meters can provide the utility with an extensive view of voltage levels throughout the distribution system and may provide other measurements that allow the utility to evaluate system harmonics and power factor. The ability to achieve the benefits for this application largely depend on the capability of the meter to perform measurements that are not normally associated with traditional metering functionality and the network capacity to transport the additional data. Table is in Appendix L.

Prepayment with AMI

A prepayment program provides customers with an option to purchase electricity in advance of its use by purchasing a specified amount of electricity at a specified price. Such programs typically include automatic disconnection of service when the customer's usage exceeds the amount of electricity purchased. Prepayment can serve as an alternative to deposit requirements for utility service, and may reduce the utility's credit and collection costs, as well as provide a structure to assist customers in reducing their electricity usage. Table is in Appendix L.

In-premises Devices for Energy Usage Data

In-premises devices receive and display energy usage information to customers. This information can be used by customers to manage their energy consumption. AMI meters can be used to communicate energy usage data to in-premises devices using a communications network (e.g., HAN). Communication to in-premises devices could be accomplished with technologies such as cellular networks, traditional wire phone services, broadband internet connections or private networks. Table is in Appendix L.

Outage Notification to Customer

An enhanced outage management system integrated with AMI, can inform customers through automated emails, web portals, social networking, text messages and phone calls of existing outages and estimated restoration times. Customers voluntarily receiving this information can make better decisions on how to respond to the outages. Table is in Appendix L.

Sharing Customer Data

This application is a high level representation of scenarios allowing customers to choose to share all or a portion of their energy usage data, outage status, rate plans or energy cost data with parties other than their distribution utility. The Collaborative assumes that the customer would control access to their data and determine what parties would be able to view specific types of information. Customers would also be informed of how various parties intend to use the data. Table is in Appendix L.

Pricing Information to In-Premise Devices

Demand response generated by price signals leaves the customer in control of how they wish to participate during periods when energy costs vary. Price based demand response requires that the customer has more real time information to automate the response. This application assumes that price based demand response can be as simple as a fixed schedule, tiered, time of use rate, critical peak pricing and critical peak rebates or a more dynamic interval based real time price rate. More dynamic rate structures may require additional automation of in-premise devices to maximize the application's benefits. Table is in Appendix L.

Direct Load Control

Demand response can be provided by installing load control devices that receive a signal from the utility or third party to reduce load at the controlled device. Customers may be able to override the direct load control request. Two-way communication ensures that intended devices get the direct control request and respond accordingly and allow the requester of the load control event to know if a customer opted out. Table is in Appendix L.

System Frequency Signal to Customer Load Control Devices

Customer devices or appliances equipped with electric system frequency sensors can detect changes in the electric system frequency that indicate instability due to insufficient generation and drop load. Frequency sensing can be added to existing appliances or for very low cost to be incorporated into future appliance designs. Customers could provide frequency response load reduction to utilities or third parties in exchange for a financial benefit. Table is in Appendix L.

Renewable Output to Customers

Customer displays or devices could receive information about the current output of the electric system's renewable generation. The customer can choose to reduce their energy usage or program devices to use less energy when renewable output is low. Information about the system's renewable output is provided by the regional transmission operator or the utility. Table is in Appendix L.

Automatic Circuit Reconfiguration

A distribution system can use communicating switches and circuit reclosers to reconfigure the distribution system during an outage, a degraded circuit condition or load balancing. For example, an automatic reconfiguration allows for a portion of customers who would traditionally suffer a distribution level outage to have their power restored in a few seconds. The system may also provide better information to the utility about the location of faults and the current configuration of the distribution system. Table is in Appendix L.

Improved Fault Location

Additional distribution sensors with network communication capability may be installed to improve the utility's ability to detect the location of system faults. The fault sensors can report to the utility distribution management system and help pinpoint the location of system faults. Table is in Appendix L.

Dynamic System Protection for Two-Way Power Flows and Distributed Resources

Most distribution systems are designed primarily for one-way power flow to customer end points. As distributed resources become more prevalent, the distribution system will require sensing of local system conditions and distributed generation resources such as battery, photovoltaic and wind. Automated control signals will adjust line devices and distributed resource output to maintain safety and stability of the distribution system within the affected area. Table is in Appendix L.

Dynamic Volt/Var Management

The smart distribution system can monitor voltage and power quality at multiple points throughout the system, including at customer AMI meters. This application would include the use of voltage and power quality monitoring devices along with capacitor bank and load tap changing transformer controls to control the voltage and reactive power on the system. System benefits of volt/Var management include reliability and voltage stabilization. While AMI meters would likely be used to provide voltage measurements at points throughout the distribution system, an AMI system is not required for this application and voltage measurements may be provided by sensing devices installed on the distribution system specifically for this application. Table is in Appendix L.

Conservation Voltage Optimization

This application is an extension of Dynamic Volt/Var Management. The smart distribution system can sense and control the voltage level at finer granularity across the entire distribution circuit and down to extended laterals. Utilities can maintain a lower regulated voltage across the distribution circuit thus providing reduced energy consumption and increasing system efficiency. This application would include the use of voltage and power quality monitoring devices along with capacitor bank and load tap changing transformer controls to maintain the voltage and reactive power on the system for energy conservation. This application could be used in a near real-time manner to reduce usage during periods of high energy costs, low load conditions or to alleviate system congestion. Table is in Appendix L.

Enhanced System Modeling and Planning

Data from AMI meters and distribution system sensors allows the utility to validate system models and efficiently plan for system upgrades, new customer loads and distributed resource integration. When sufficient numbers of sensors are in place and data are available, some traditional power flow models can be updated with true representations of the system during diverse operational conditions. Table is in Appendix L.

Asset Size Optimization

Data provided by AMI meters and new distribution system sensing devices enable the utility to accurately determine load and view operational attributes of distribution system components over time. The increase in system visibility allows the utility to correctly size system components such as distribution transformers and replace them based on actual operating conditions. This application is used operationally in a more dynamic manner than the long-term system modeling and planning application. Table is in Appendix L.

Asset Condition Monitoring

Distribution and transmission system sensors that detect temperature and battery condition allow the utility to monitor the real time performance and health of system components. The utility can take corrective action at the appropriate time resulting in increased system reliability, operational efficiency and optimized equipment maintenance cycles. Table is in Appendix L.

Customer Distributed Resource Interconnection

Customer-owned generation resources can provide power into the distribution system and help defer construction of new generation or increase the use of renewable energy. The smart grid can facilitate the interconnection of customer generation and storage by providing technical support and the implementation of other applications that encourage the installation of distributed resources. Customer-owned generation and storage is possible today, but AMI and other smart grid applications could allow customers to better utilize their own generation and storage and potentially to provide power back to the electric system. Table is in Appendix L.

Coordinated Management of Distributed Resources

Permitting the utility to communicate with customer or utility-owned generation such as wind, solar or battery can allow the utility to better manage the distribution system. A utility system that is aware of the operating condition and output of distributed resources can provide better system protection and reliability. This application envisions a scenario where the utility or third party enroll the customer with distributed resources in a voluntary program that allows the utility or other entity to operate the customer's generation based on market conditions or for purposes of reliability. This application includes both small and large scale generation and storage devices. Table is in Appendix L.

PEVs: Optimized Charging

High market penetration of PEVs will add significant load to specific areas of the distribution system which could be managed through the use of smart charging systems. Dense localized deployment of PEVs and charging stations may strain local distribution system devices. Smart charging systems include features such as time delayed charging, time-of-use controls; pricing signal controls, critical peak controls and automated load shed controls. Table is in Appendix L.

Dispatch of PEV Storage

PEVs may provide stored energy as a backup resource when system and market conditions are appropriate. Technology controls are required to enable the two-way power flow of energy from the vehicle batteries through the charging station into the distribution grid. Near real-time energy flow will either be locally controlled or dispatched and actively managed by the electric utility control center.

V2G dispatch may have a difficult economic case using available technology based on the increased wear on a vehicle's battery from a greater number of charge/discharge cycles. In addition, V2G would be subject to trade-off evaluation by customers choosing between maintaining vehicle charge levels and obtaining market value for the stored electricity. Table is in Appendix L.

Wide Area Phasor Measurement

Improved communications and sensors allow better visibility and decision-making for transmission system operations. Phasor measurement units in substations can measure system phase angles 30 times per second. The data is transmitted back to a control center to determine phase angle differences at various points of the grid. The phase angle differences provide improved situational awareness and should improve grid stability. The technology for this application is mature and wide area measurement devices and systems are being increasingly deployed. Table is in Appendix L.

Recommendations

The Codes and Standards Workgroup has established short-term and long-term recommendations for implementing smart grid. The short-term recommendations are intended to be realized from the publishing of this document for the next three years. The long-term recommendations are intended to be implemented in the next three years and beyond.

Short-Term Recommendations

- Establish a repository of references for codes and standards (could be formal document or just a reference to NIST).
- Actively participate and/or monitoring in the following groups: SGIP, OpenSG, NIST, and other significant standard development. Organizations such as IEEE, ANSI, ZigBee, NAESB, etc. with monthly collaboration with our involvement.
- Drive structural changes needed within SGIP to address the reliability and implementation impacts that standards could have on the utility industry.
- Establish positions on critical codes and standards issues that represent the stakeholders in the Collaborative, (i.e., RF and privacy).

Long-Term Recommendations

- Remain in compliance with industry best practices and standards as identified for smart grid interoperability.
- Evaluate the codes and standards and technology required for the interoperability of communication and distribution system networks.

Summary and Conclusions

The Codes and Standards Workgroup supports the benefits of a uniform set of interoperability standards for smart grid technologies. We believe interoperability standards will help stakeholders avoid vendor lock-in, enable technology innovation, reduce the risk of premature technological obsolescence and reduce cost by supporting a global market for smart grid technologies.

Due to the vast amount of standards setting organizations and the overlapping of activity within the smart grid industry, this workgroup has determined that we need to strategically focus our efforts. The Codes and Standards Workgroup will continue to provide an effective forum for evaluating and focusing our involvement in the national standards development work.

The Codes and Standards Workgroup has concluded that while many important and useful standards for smart grid applications exist, there are notable gaps (e.g., over the air upgrades, communication protocols for mesh networks, etc.) that need to be addressed. While these gaps are important, this workgroup recommends that smart grid investments proceed and the companies implementing smart grid technology shall continue to work within the industry to find solutions for the existing gaps.

The Codes and Standards Workgroup will continue to meet on a regular basis and work toward the achievement of our stated goals. We collectively agree that the application of interoperability standards by the stakeholders is not mandatory but recommended along with the sources noted below:

- NIST Framework and Roadmap
- SGIP Catalog of Standards
- IEEE smart grid related standards reference
- DOE smart grid Clearinghouse
- UCAIug OpenSG Task Force

Interoperability standards will continue to play a key role in the investment decisions made in grid modernization for Michigan utilities. Our electric grid is becoming more automated. Customers are beginning to play more active roles in their energy decisions. System control, energy generation and storage resources are becoming less centralized. The need for interoperable, standards-driven technologies will expand in order to deliver customer value and continued energy reliability. Standards will play an increasingly key role in enabling a smarter electric grid and will continue to develop and evolve over time.

APPENDIX B

Acronyms

APPENDIX B: Acronyms

-A-

AFUDC: Allowance for Funds used during Construction

AMI: Advanced Metering Infrastructure

AMR: Automatic Meter Reading

ANSI: American National Standards Institute

ARRA: American Recovery and Reinvestment Act

ASAP SG: Advanced Security Acceleration Project-Smart Grid

ASHRAE: American Society of Heating, Refrigerating and Air Conditioning Engineers

ASIDI: Average Service Interruption Duration Index

ASIFI: Average Service Interruption Frequency Index

ASM: Ancillary Services Market

ATC: American Transmission Company

-B-

BES: Bulk Electric System

-C-

C&I: Commercial & Industrial

CAIDI: Customer Average Interruption Duration Index

CDMA: Code Division Multiple Access

CE: Consumers Energy

CIM: Common Information Model

CIP: Critical Infrastructure Protection

CSCTG: Cyber Security Coordination Task Group

CWIP: Construction Work In-Process

-D-

DA: Distribution Automation

DC: Direct Current

DDR: Dynamic Disturbance Recorder

DFR: Digital Fault Recorder

DGA: Dissolved Gas Analysis

DLC: Direct Load Control

DMS: Distribution Management System

DNP: Distributed Network Protocol

DOE: Department Of Energy

DOT: Department of Transportation (on US DOT)

DPP: Dynamic Peak Pricing Rate

DR: Distribution Resources

DTE: Detroit Edison

-E-

EARP: CE's Experimental Advanced Renewable Program

EEI: Edison Electric Institute

EI: Eastern Interconnection

EISA: Energy Independence and Security Act

EMS: Energy Management System

EPA: US Environmental Protection Agency (or US EPA)

EPRI: Electric Power Research Institute

ESI: Energy Services Interface

EV: Electric Vehicles

-F-

FAQ: Frequently Asked Questions

FERC: Federal Energy Regulatory Commission

-G-

G&T: Generation and Transmission

GIC: Geomagnetic Induced Current

GIS: Geographic Information System

GPS: Global Positioning System

GSM: Global System for Mobile Communications

GWAC: GridWise Architecture Council

-H-

HAN: Home Area Network

HVDC: High Voltage Direct Current

-I-

I&M: Indiana Michigan Power Company

ICCP Inter-control Center Communications Protocol

IEC: International Electrotechnical Commission

IED: Intelligent Electronic Device

IEEE: Institute of Electrical and Electronics Engineers

IETF: Internet Engineering Task Force

IHD: In Home Devices

IOU: Investor Owned Utilities

IRR: Internal Rate of Return

ISO: Independent System Operator (also, see MISO)

ISO: International Organization for Standardization

IT: Information Technology

ITC: International Transmission Company, LLC

-K-

Kv: Kilovolt

kWh: Kilowatt

kVA: Kilovolt Amperage

-L-

LP: Lower Peninsula of Michigan

-M-

MAIFI: Momentary Average Interruption Frequency Index

MEGA: Michigan Electric & Gas Association

METC: Michigan Electric Transmission Company

MISO: Midwest Independent System Operator (also, see ISO)

MPSC: Michigan Public Service Commission

MW: Megawatt

-N-

NAESB: North American Energy Service Board

NARUC: National Association of Regulatory Utility Commissioners

NASPI: North American Synchrophasor Initiative

NERC CIP: North American Energy Reliability Corp-Critical Infrastructure Protection

NERC: North American Electric Reliability Corporation

NESCO: National Electric Sector Cyber Security Organization

NESCOR: National Electric Sector Cyber Security Organization Resource

NIST: National Institute of Standards and Technology

NISTIR: National Institute of Technology Internal Report

NPV: Net Present Value

NRECA: National Rural Electric Cooperative Association

-O-

O&M: Operations and Maintenance

OEMs: Original Equipment Manufacturer

-P-

PA: Public Act

PAP: Priority Action Plan

PCT: Programmable Communicating Thermostat

PDC: Phasor Data Concentrators

PEVs: Plug-In Electric Vehicles

PMU: Phasor Measurement Unit

PSCR Electric Power Supply Cost Recovery

-R-

RF: Radio Frequency

RIM: Rate Impact Measure

RTO: Regional Transmission Organization

RTU: Remote Terminal Unit

-S-

SAE: Society of Automotive Engineers

SCADA: Supervisory Control and Data Acquisition

SCD: Security Constrained Dispatch

SCE: Southern California Edison

SDG&E San Diego Gas and Electric

SDO: Standards Development Organizations

SE: State Estimator

SEL: Schweitzer Engineering Laboratories

SG: Smart Grid

SGIG: Smart Grid Investment Grant

SGIP: Smart Grid Interoperability Panel

SGPP: Smart Grid Pilot Program

SOE: Sequence of Events

SMPP: I & M's Smart Meter Pilot Program

SPS: Special Protection System/Schemes

STATCOM: Static Synchronous Compensator

SSO: Standards

-T-

TOD: Time of Day (Rates)

TOU: Time of Use (Rates)

TRC: Total Resource Costs

TSO: Transmission System Operator

-U-

UCAIug: Utility Communication Architecture International users group

UCT: Utility Costs Test

UP: Upper Peninsula of Michigan

USOA: Uniform System of Accounts

-V-

V2G: Vehicle to Grid

V2H: Vehicle to Home

VAR: Volt-ampere reactive

VSC: Voltage Source Converter

-W-

WACC: Weighted Average Cost of Capital

WAMS: Wide Area Management Systems

WPSCI: Wolverine Power Supply Cooperative Inc

APPENDIX C

Overview of Cross-Cutting Issues

APPENDIX C: Overview of Cross-Cutting Issues

Issue	Steering Committee	Customer Programs & Communication	Regulatory Policy - Deployment & Customer Protection Subgroup	Regulatory Policy - Cost/Benefit Subgroup	Regulatory Policy - Cost Recovery Subgroup	Codes & Standards	Distribution & Grid Apps	G&T
Privacy	Observing	Communicate Privacy Assurance	Discussing customer data privacy policy and current practice	n/a	n/a	Observing and Participating in SGIP / NIST process / other various SDOs	common(3rd party) communications platform feasibility discussion	n/a
3rd party access to customer data	Observing	Communicate potential privacy assurance and customer consent policy	NAESB currently developing Privacy policy (REQ 22) for 3rd party data access and privacy and potential need for assurance regulation.	n/a	n/a	NAESB has a working group, the CSWG is working on a privacy and customer data use NISTIR	common(3rd party) communications platform feasibility discussion	n/a
RF	n/a	Addressed as communication of facts to the customer that are timely with respect to implementation	n/a	n/a	n/a	All meters meet FCC standards	NA	n/a
Remote disconnect/ reconnect	Observing benefits	Communicate Current Admin Rules and customer benefits	Review current regulations and assess need for updates	Explore costs and benefits	n/a	Identify potential standards to execute	Include in Benefit Assessment Form	NA
Opt out	No Policy will be developed for Opt-out, Customers with issues are being addressed case-by case with positive results	Not currently being discussed	Not currently being discussed	Not currently being discussed	Not currently being discussed	NA	NA	NA
Cyber security	Observe	Address as privacy	Implementation guide needed for	Not currently being	Not currently being	Observe and Participate in SGIP / NIST process	n/a	NERC-CIP

Issue	Steering Committee	Customer Programs & Communication	Regulatory Policy - Deployment & Customer Protection Subgroup	Regulatory Policy - Cost/Benefit Subgroup	Regulatory Policy - Cost Recovery Subgroup	Codes & Standards	Distribution & Grid Apps	G&T
		assurance	application of the NIST cyber Security guideline NISTIR 7628	discussed	discussed			
Interoperability	Observe	Address communication about smart grid benefits	Continue to Monitor FERC activities surrounding SG and SGIP activities	Not currently being discussed	Discuss potential for stranded asset	Look at all SG applications for interoperability standards and gaps in standards	Observe	FERC to adopt necessary interoperability standards and protocols
Meter Security - data security at the meter	n/a	Address as privacy assurance only	Address as customer privacy and data security at the meter	Discuss cost as an input to analysis	Not currently being discussed	Observe and Participate in SGIP / NIST process / other various SDOs	n/a	NA
Cost/Benefit	Observe	Educate customer as to customer benefits	n/a	Examine cost benefit frameworks	Central to workgroup activities	NA	Priority of application implementation being discussed	FERC (Formula determines cost allocation based on benefit received)
O&M costs	n/a	n/a	TBD	Central to workgroup activities	Central to workgroup activities	NA	Include in Benefit Assessment Form	FERC (Cost Based Formula)
Networking/ Communication	n/a	n/a	Address the avoidance of dual network issues	Examine as potential cost	Potential cost	Categorize all SG applications for networking/communication standards and gaps in standards	Discuss priority of application implementation, common communication platform discussion	n/a

APPENDIX D

Smart Grid National Websites

APPENDIX D: Smart Grid National Websites

www.Consumersenergy.com: Consumers Energy, 2011.

www.smartgrid.gov: Department of Energy, 2011.

www.dteenergy.com: DTE Energy Company, 2011.

www.duke-energy.com: Duke Energy Corporation, 2011.

www.itsyoursmartgrid.com: General Electric Company, 2011.

www.michigan.gov/smartgrid: Michigan Public Service Commission, 2011.

www.npr.org: National Public Radio, 2011.

www.oge.com: Oklahoma Gas and Electric, 2011.

www.srpnet.com: Salt River Project, 2011.

APPENDIX E

Current Deployment Status
By Michigan Investor Owned Utilities

APPENDIX E: Current Deployment Status by Michigan Investor Owned Utilities

Smart Grid Applications	DTE			Consumers Energy			AEP/I&M		
	Current	1-3 year	4+ year	Current	1-3 year	4+ year	Current	1-3 year	4+ year
AMI Applications					X				
Core AMI Functions	X				X			X	
Remote Connect/Disconnect	X				X			X	
Outage Management Support		X			X			X	
Power Quality/Voltage Monitoring at the Meter		X			X			X	
Customer Prepayment Utilizing AMI		X				X			X
Customer-Oriented Applications									
In-premises Devices for Energy Usage Data		X			X			X	
Customer Web Portal for Energy and Cost Data		X		X				X	
Outage Notification to Customer		X			X			X	
Government and Third Party Use of Customer Data						X			X
Demand Response									
Pricing Information to In-premise Devices						X			X
Direct Load Control	X	X	X	X				X	
System Frequency Signal to Customer Load Control						X			X
Systems Renewable Output to Customers						X			X
Distribution Automation									
Automatic Circuit Reconfiguration		X	X	X				X	
Improved Fault Location		X	X		X			X	
Dynamic System Protection for Two-way Power Flows and Distributed Resources						X			X
Dynamic Volt-VAR Management		X	X		X				X
Conservation Voltage Optimization					X			X	
Asset/System Optimization									
Enhanced System Modeling and Planning		X	X		X				X
Asset Sizing Optimization		X	X		X				X
Asset Condition Monitoring		X	X			X	X		
Distributed Resources									
Customer Distributed Resource Integration	X	X	X	X					X
Coordinated Management of Distributed Resources						X			X
Electric Vehicles: Optimized Charging		X	X	X					X
Dispatch of Electric Vehicle Storage						X			X

APPENDIX F

Current Deployment Status Descriptions

APPENDIX F: Current Deployment Status Descriptions

CURRENT DEPLOYMENT STATUS			
	DTE	CE	I&M
AMI Applications			
Core AMI Functions	500,000 meters installed with 800,000 total planned by 2012	Presently planning on beginning AMI deployment in 2012. Meters will enable core AMI functionality	
Remote Connect/Disconnect	All meters installed have remote connect and disconnect	Presently planned to have integrated service switch in Form 2S 200A self-contained meters	10,000 customer pilot in South Bend, IN. Continuing remote implementation of open/close orders and disconnect/reconnect. Monitoring saved field trips due to the use of these remote processes. Considering future expansion of pilot area in urban areas of South Bend District approximately 60,000 meters

CURRENT DEPLOYMENT STATUS			
	DTE	CE	I&M
Outage Management Support	All meters will send outage message on loss of voltage. Experimenting with sending outage messages to dispatch system	AMI meters will report last gasp (loss of voltage) message and return of voltage message.	10,000 customer pilot in South Bend, IN. Continuing remote outage reporting via AMI meters with outage reporting integrated into I&M's OMS and outage prediction engine in order to provide the scope of the verified outage. Currently running remote outage reporting via AMI meters (last gasp) in test mode to verify validity of last gasp messages reported through the filters developed by I&M
Power Quality/Voltage Monitoring at the Meter	All meters have voltage reporting capability, and DTE is planning to capture that information for outage analysis	AMI meters will have the capability of reporting various degrees of power quality and voltage measurements based upon meter class and customer needs	10,000 customer pilot in South Bend, IN. Continuing remote pinging/polling of meters to provide voltage measurements at the AMI meters
Customer Prepayment Utilizing AMI	Will be part of the DOE/Smart Grid Investment Grant (SGIG) Smart Home Project	Under evaluation as possible future application	Considered for South Bend Pilot, but eventually not included due to cost of technology, budget limitations of pilot, and existing customer order processing system upgrades required to implement. Not considering future installations at this time

CURRENT DEPLOYMENT STATUS			
	DTE	CE	I&M
Customer-Oriented Applications			
In-premises Devices for Energy Usage Data	In home energy management system will be part of the DOE/SGIG Smart Home project	Several in-premise devices are being tested in CE's Smart Services Learning Center for energy usage data	10,000 customer pilot in South Bend, IN. Continuation of programmable controlling thermostat (PCT) support where installed in pilot (approx. 120 customers). PCT used solely for piloting Direct Load Control program that controlled temperature set points to manage air conditioning peak during peak periods
Customer Web Portal for Energy and Cost Data	Operational in pilot phase under the DOE/SGIG Smart Home project	The Demand Response pilot provided a customer web portal for viewing of usage data	10,000 customer pilot in South Bend, IN. Continuing a web portal for those customers in the pilot that have an AMI meter. Web Portal provides ability to view interval consumption data from AMI meter
Outage Notification to Customer	Under review	Under evaluation as possible future application	I&M is piloting a program to notify customers via text messages or emails for those customers that sign up. This program is not affiliated with a smart meter installation
Government and Third Party Use of Customer Data	DTE will not share uniquely identifiable customer data without customer approval	CE will not share uniquely identifiable customer data without customer approval	Currently, I&M does not provide use of customer data unless confidentiality and customer agreement for sharing is obtained

CURRENT DEPLOYMENT STATUS			
	DTE	CE	I&M
Demand Response			
Pricing Information to In-premise Devices	Critical peak pricing will be communicated day ahead via email. No direct communication with In-Home Displays planned	Under evaluation as possible future application	I&M is not currently sending pricing signals to in-home devices in the South Bend Pilot
Direct Load Control	DTE currently has about 56,300 customers with interruptible hot water heaters and about 280,000 customers with interruptible air conditioners	Presently being piloted	10,000 customer pilot in South Bend, IN. Continuing the direct load control tariff to those customers in the pilot who have signed up. I&M is not taking new entrants at this time. Considering future expansion of pilot area into urban areas of South Bend District in I&M, approximately 60,000 meters total where future offering may be developed for pricing signals
System Frequency Signal to Customer Load Control Devices	Not under consideration	Under evaluation as possible future application	No implementation or plans at this time

CURRENT DEPLOYMENT STATUS			
	DTE	CE	I&M
Systems Renewable Output to Customers	Not under consideration	Under evaluation as possible future application	No implementation or plans at this time.
Distribution Automation			
Automatic Circuit Reconfiguration	Distribution automation implementation began in 1990 and continues to be strategically deployed. Enhanced recloser looping scheme with centralized Distribution Management System (DMS) is being implemented as part of the DOE-SGIG project	Distribution automation has been a tool used for reliability improvement since the 1990's and will continue to be used for this purpose on a go forward basis. Currently, CE has distribution automation schemes on its overhead and underground distribution system. We are implementing different types of products and automatic circuit reconfiguration strategies to determine the best fit for different distribution system configurations	8 distribution circuit pilot as part of South Bend smart meter pilot. Automated circuit reconfiguration with basic load analysis decision making incorporated into scheme functionality. Also, there is a two distribution circuit DA system implemented in the Almena Michigan service territory in Michigan using similar technology as South Bend pilot

CURRENT DEPLOYMENT STATUS			
	DTE	CE	I&M
Improved Fault Location	Fault locating is being implemented as part of the DMS associated with the DOE-SGIG project (11 substations, 55 circuits)	Fault locating has been successfully used on the High Voltage Distribution System. We are presently in the initial phases of developing a program to expand our deployment of Distribution SCADA and implement a Distribution Management System (DMS), and this functionality is planned to be included as part of the DMS functionality for the Low Voltage Distribution system	8 distribution circuit pilot as part of South Bend smart meter pilot. Automated circuit reconfiguration with basic load analysis decision making incorporated into scheme functionality. Also, there is a two distribution circuit DA system implemented in the Almena Michigan service territory in Michigan using similar technology as South Bend pilot
Dynamic System Protection for Two-way Power Flows and Distributed Resources	Under review.	Under evaluation as possible future application	I&M owned NaS battery installation in Churubusco, IN that provides peak shaving for adjacent substation transformer and also Islanding, which is outage restoration for a defined area of customers. Installation includes full SCADA capability and automated DA switches for the islanding capability. I&M has several other similar installations in other states. No further installations planned at this time

CURRENT DEPLOYMENT STATUS			
	DTE	CE	I&M
Dynamic Volt/Var Management	Planned as part of the DOE-SGIG project	Systems and equipment are being installed to enable this functionality to be piloted. This functionality is planned to be included as part of the DMS functionality for the Low Voltage Distribution system	No implementation or plans at this time
Conservation Voltage Optimization	No plans at this time	In collaboration with the Electric Power Research Institute (EPRI), pilot projects are underway to provide a Conservation Voltage Management proof of concept	Developing plans to implement smart voltage optimization on heaviest loaded circuits in Indiana and Michigan jurisdictions in near term using smart grid technologies and automated feedback processes
Asset/System Optimization			
Enhanced System Modeling and Planning	11 substations and 55 circuits have been modeled as part of the DOE-SGIG project	In collaboration with EPRI, pilot projects were completed as part of the Green Circuit Collaboration that created an enhanced system model on four distribution circuits which was used for system loss modeling and planning studies. CE has an ongoing project to collect and store System infrastructure information. This project will enhance the current infrastructure information over a multi-year period	No implementation or plans at this time

CURRENT DEPLOYMENT STATUS			
	DTE	CE	I&M
Asset Sizing Optimization	Under consideration, dependent on data obtained from DOE-SGIG project	Some preliminary analysis was done as part of AMI and Grid Modernization pilots, remains under continued evaluation for future application	No implementation or plans at this time
Asset Condition Monitoring	Substation Dissolved Gas Analysis (DGA) being implemented as part of DOE-SGIG project.	Some preliminary analysis was done as part of AMI and Grid Modernization pilots. Under evaluation for a future application.	8 distribution circuit pilot as part of South Bend smart meter pilot. Remotely controlling and monitoring status and data from capacitors banks installed on the 8 circuits in the pilot
Distributed Resources			
Customer Distributed Resource Integration	The SolarCurrents customer-owned pilot program provided financial incentives for customers who install solar energy systems on their homes and businesses. This program is closed because it's fully subscribed. Net metering program is still in effect	An Experimental Advanced Renewable Program (EARP) has been implemented as part of our Renewable Energy Plan. EARP is a solar "feed-in tariff" that will enable CE to meet the State's require renewable portfolio standard	No implementation or plans at this time
Coordinated Management of Distributed Resources	DR managed by dedicated control center	Under evaluation as possible future application	No implementation or plans at this time

CURRENT DEPLOYMENT STATUS			
	DTE	CE	I&M
Electric Vehicles: Optimized Charging	EV rates approved by MPSC	Electric Vehicle charging rates have been filed with the MPSC	No implementation or plans at this time.
Dispatch of Electric Vehicle Storage	Under review	Under evaluation as possible future application.	No implementation or plans at this time.

APPENDIX G

Grid Applications Benefit Assessment

APPENDIX G: Grid Applications Benefit Assessment

Outage Management Support						
Regulatory Impact	Benefit			Impact		
Medium	Customer	Utility	Other	Customer	Utility	Other
Existing systems may be able to perform some of outage management support functions, additional information can be integrated into existing processes, outage verification rules, impact on reliability reporting requirements.	Improved outage estimates, active and after-the-fact outage information availability, shortened system outage times, no need to call to report outages.	Reduced trouble after initial restoration, positive impact on CAIDI, “last gasp” outage reporting, meter “ping” test, momentary outage analysis, reduction in nested outages, operational cost reduction, improved productivity, increased reliability and awareness.			Outage management support system integration requirements issues.	

Power Quality/Voltage Monitoring at the Meter						
Regulatory Impact	Benefit			Impact		
Medium	Customer	Utility	Other	Customer	Utility	Other
Cost recovery policy, currently being implemented today but not to the scale that will be available with AMI, there may also need to be updated guidelines on how to proceed with newly available measurements, possible impact on reliability reporting requirements.	Verification of customer complaints without delay associated with field visit/testing, improved reliability and power quality.	Faster problem resolution, proactive response to power quality issues, increased reliability and awareness, momentary outage detection can improve efficiency.				

Customer Prepayment Utilizing AMI						
Regulatory Impact	Benefit			Impact		
High	Customer	Utility	Other	Customer	Utility	Other
Policy on how to recover costs associated with implementation, possibly new rates needed, prepay is being addressed in pending proposed billing rule changes (MEGA), possible changes to process and payment rules and requirements.	Energy cost management, energy reduction incentive, greater service options, increased usage awareness, improved payment options.	Fewer customer late payments, revenue enhancement, better customer service.		Customer familiarity/comfort with technology may be an issue.	Internal process changes needed to accommodate this application, customer payment management, billing system integration requirement issues.	

In-Premise Devices for Energy Usage Data						
Regulatory Impact	Benefit			Impact		
High	Customer	Utility	Other	Customer	Utility	Other
Policy on cost recovery of large costs associated with information systems required to provide real time data, need standards on what data is shared (how and to whom?) what customers this should be offered to, how to charge customers for devices (if at all), what kind of devices should be offered if the utilities provide them (standard or more advanced models?).	Increased knowledge of energy consumption and impact of usage changes, energy / demand reduction incentive.	Facilitates Dynamic Peak Pricing and Demand Management, potential for reduced load at peak due to customer engagement.	New markets.	Cost of in-premises devices, potential for non-interoperability due to evolving technology.	Cost of web portal and consumption data could be high ($millions) depending on data frequency, need for added communications capabilities, potential for non-interoperability.	

Customer Web Portal for Energy & Cost Data						
Regulatory Impact	Benefit			Impact		
Low	Customer	Utility	Other	Customer	Utility	Other
Cost recovery policy, need standards on what data is shared (how and to whom), decisions on who should be offered the service (only offer to those with internet access?).	Facilitates energy and demand reduction behavior changes.	An opportunity to improve customer satisfaction and increase customer interaction, potential for reduced load at peak due to customer engagement.		Setup and learning curve could be frustrating, Internet (possibly broadband) connection required.	Cost of web portal (storing and reporting data) could be very high ($ Millions), customer data security.	

Outage Notification to Customer						
Regulatory Impact	Benefit			Impact		
Low-Medium	Customer	Utility	Other	Customer	Utility	Other
Policy on cost recovery of large cost associated with information systems required to provide outage notification, need standards on what data is shared (how and to whom).	Ability for customer to plan whether to stay at home or go elsewhere, improved customer service.	Possible improvement in customer satisfaction, lower costs to report, increased utilization of automated systems.		Accuracy of estimate may not be sufficient early in an outage, especially after severe storm.	Cost of improving accuracy estimates, utility needs to assure accurate reporting.	
Government & Third Party Use of Customer Data						
Regulatory Impact	Benefit			Impact		
High	Customer	Utility	Other	Customer	Utility	Other
Policy needed on whether customer must approve third party use of personally identifiable data, need standards on what data is shared (how and to whom), possible need for rules for whom the data is to be released to.	Ability to compare energy consumption to others, greater service and energy management options.	Increased revenue.	New markets.	Potential for customer privacy breach.	Data privacy of customer needs to be protected, potential liability for unauthorized transfer of customer information, increased competition from third parties.	

Pricing Information to In-Premise Devices						
Regulatory Impact	Benefit			Impact		
High	Customer	Utility	Other	Customer	Utility	Other
Controversy over using the meter as a communications portal must be resolved, possible new rate structures needed for time-of-use rates, possible need for rules addressing what media will receive the pricing information - web portal, by phone, email, text other mobile media? Finally, there may be a need for policies that address opt in/out for various pricing schedules.	More accurate cost allocation, energy conservation, reduced demand, lower energy costs, greater reliability, deferred capacity costs.	Improved reliability, deferred investments.	New markets.	Data privacy may be a concern, In-Home-Display programming may frustrate customers, cost vs. savings issues, need for customers to be aware of cost during usage, increased costs for customers who cannot shift usage to low cost periods.	Cost and security will limit acquisition of price data to the Internet and not the AMI system, potential for increased complaints from customers who cannot shift to low cost periods.	

Direct Load Control						
Regulatory Impact	Benefit			Impact		
Low-Medium	Customer	Utility	Other	Customer	Utility	Other
May need revised rates, policy must be developed that decides how far utilities may reach into homes to control individual appliances.	Lower energy cost, energy conservation resulting in energy demand/cost control, deferred capacity costs.	Immediate load reduction when needed, system optimization, improved reliability, deferred investments.	Increased market for load control equipment.	Customer concern over "big brother" controlling their devices and ability to use them, impact to customer comfort during interruption event.	While interruptible air conditioning is a current and well received program for many utilities, reaching inside the home to individual devices will create customer satisfaction issues.	
System Frequency Signal to Customer Load Control						
Regulatory Impact	Benefit			Impact		
High	Customer	Utility	Other	Customer	Utility	Other
New rates to compensate for ancillary services opt in/out requirements, rules over load shedding.	Reduced costs.	Increased grid stability.	RTO/ISO – increased grid stability.	Cost of equipment, impact to customer comfort during interruption event.	Difficult to explain the need to a customer absent a major system event, impact to ancillary service market.	
System Renewable Output to Customers						
Regulatory Impact	Benefit			Impact		
Low-Medium	Customer	Utility	Other	Customer	Utility	Other
No customer interest unless it affects cost, need standards on what data is shared (how and to whom), delivery medium for information.	Customer has greater choice.	Better customer service.	Potential decrease in carbon footprint/ greenhouse gas.		Expensive to provide, minimal value to customer, compilation of data from multiple sites requires consistent reporting and output views.	

Automatic Circuit Reconfiguration						
Regulatory Impact	Benefit			Impact		
Low-Medium	Customer	Utility	Other	Customer	Utility	Other
Cost recovery policy needed for customer benefits.	Reduced interruption duration for many customers, improved reliability and power quality.	Increased productivity, increased reliability, extended asset life, situational awareness, improved worker safety.	Increased market for communication equipment and network.		Reduced outage duration for many customers, but quickly isolating severe damage may negatively impact the calculation of duration metrics. Need to maintain historical system configurations for planning purposes. Revise planning criteria to allow for more alternative feeds.	
Improved Fault Location						
Regulatory Impact	Benefit			Impact		
Low-Medium	Customer	Utility	Other	Customer	Utility	Other
Cost recovery policy needed for customer benefits but otherwise regulatory impact should be minimal.	Reduced outage duration, improved reliability and customer service.	Reduced cost of restoring outage, increased productivity, increased reliability, extended asset life, situational awareness, and improved worker safety.			Cost of equipment and control systems may become a long-term issue.	

Dynamic System Protection for Two-way Power						
Regulatory Impact	Benefit			Impact		
Medium	Customer	Utility	Other	Customer	Utility	Other
Cost recovery policy needed, may need new rules on how to interconnect with distributed resources, potential new public safety response requirements.	Improved reliability if islanding is utilized, improved ability to interconnect generation.	Improved reliability, situation awareness, and employee safety.	Increased demand for renewable industry.		Safety of public and employees, downed wire response, worker training requirements.	
Dynamic Volt-VAR Management						
Regulatory Impact	Benefit			Impact		
Low-Medium	Customer	Utility	Other	Customer	Utility	Other
Cost recovery policy needed, may need rate changes to assist in benefit realization (e.g. kVA metering analysis).	Stable voltage, less impact on devices in the home, improved power quality.	More efficient use of assets, system loadflow optimization, situational awareness, asset performance, reduced line losses.				
Conservation Voltage Optimization						
Regulatory Impact	Benefit			Impact		
Low-Medium-High	Customer	Utility	Other	Customer	Utility	Other
(Consensus not reached by stakeholders) Customer equipment at risk, policy on indemnification may be necessary to offset societal benefit, need mechanism for investment recovery, potential requirement to use EM&V to validate energy savings.	Energy efficiency, reduced demand & energy consumption.	Additional system operating options, improved awareness, reduced line losses, better customer service, and extended asset lives.		Risk to customer devices, especially motors. May expose inadequacies in customer wiring.	Risk of violating lower voltage limits on high load days. Less operating margin to low voltage limit and potential for less fixed cost coverage.	

Enhanced System Modeling and Planning						
Regulatory Impact	Benefit			Impact		
Low-Medium	Customer	Utility	Other	Customer	Utility	Other
Cost recovery policy for significant additional labor and computer assets to model entire electrical system at distribution level is needed, may need authorization/investment for additional operational systems and system model data acquisition.	Improved reliability and power quality, more accurate outage predictions and load addition analysis for controllable loads, better utility system with lower costs.	Enablement of automated circuit reconfiguration, advanced system diagnostics and asset management enablement, improved reliability, extended asset life, reduced procurement costs, better forecasting.	RTO/ISO – Improved forecasting.		Cost of process changes needed to keep model current and accurate, data maintenance.	

Asset Sizing Optimization						
Regulatory Impact	Benefit			Impact		
Low-Medium	Customer	Utility	Other	Customer	Utility	Other
Cost recovery policy needed for significant additional labor and computer assets to incorporate AMI data into asset optimization planning, system planning criteria review may be needed.	Lower cost/better performing system.	Longer asset life, lower failure rates, lower procurement costs, increased asset performance.			Standard sizing of service transformer may overcome the cost of capturing this data.	

Asset Condition Monitoring						
Regulatory Impact	Benefit			Impact		
Low-Medium	Customer	Utility	Other	Customer	Utility	Other
Cost recovery policy needed for significant additional labor and computer assets to incorporate AMI data into asset optimization planning, system planning criteria review may be needed.	Improved system reliability.	Predictive and condition/duty-based maintenance, increased productivity, reliability, extended asset life, and situation awareness.				

Customer Distributed Resource Integration						
Regulatory Impact	Benefit			Impact		
Medium	Customer	Utility	Other	Customer	Utility	Other
Cost recovery policy needed for significant additional labor and computer assets to incorporate DR into distribution grid operations, may need integration rule revisions, as well as rules governing consistent metering requirements, acceptable generation sources, and acceptable storage devices.	Customer can sell power to the grid.	Lower cost associated with interconnections.	Expands market for small scale renewable system and storage manufacturers.		Tracking, recording, and displaying customer equipment, modeling of all the power sources, metering requirements.	
Coordinated Management of Distributed Resources						
Regulatory Impact	Benefit			Impact		
High	Customer	Utility	Other	Customer	Utility	Other
Cost recovery policy needed for significant additional labor and computer assets to incorporate DR into distribution grid operations.	Enables customer generation and storage systems.	Improved system stability, flattened load shape, improved reliability and situation awareness.		Concern over loss of control and cost benefits.	Cost of control system and data gathering equipment, distributed resource dispatching challenges.	
Electric Vehicles: Optimized Charging						
Regulatory Impact	Benefit			Impact		
Medium-High	Customer	Utility	Other	Customer	Utility	Other
Cost recovery policy needed for significant additional labor and computer assets to incorporate EV charging into distribution grid planning and operations.	Access to lower-cost energy and increased services options.	System load support, flattened load profile, better utilization of base load generation, and control of new load impacts.	Increased market for PEV manufacturers.		Cost of control system and data gathering.	

Dispatch of Electric Vehicle Storage						
Regulatory Impact	Benefit			Impact		
Medium-High	Customer	Utility	Other	Customer	Utility	Other
Cost recovery policy needed for significant additional labor and computer assets to incorporate DR into distribution grid operations, as well as a policy on customer payment in return for allowing their battery to be dispatched, need for new rates, responsibility for impact to customer owned batteries (if utility dispatches them, will battery warranties be voided for over-use or other damage?).	Possible revenue source.	System load support, more reliable system, and load management.		Negative impact on vehicle battery life if discharging to the grid occurs. .	Cost of control system and data gathering, device management.	

APPENDIX H

Prioritization of Applications

APPENDIX H: Prioritization of Applications

Consumers Energy

	Application	Priority Rating	Comments
AMI Applications	Core AMI Functions	High	Additional information to customers will allow them to make informed decisions.
	Remote Connect/Disconnect	High	Can be used for operational benefits during system events as well as cost saving.
	Outage Management Support	High	Most outages are small (<10 customers) having this data will allow for more accurate analysis and faster response.
	Power Quality/Voltage Monitoring at the Meter	High	Service point measurements will allow for proactive response to system issues.
	Customer Prepayment Utilizing AMI	High	Utilities that have implemented this indicate it has gained significant acceptance by customers.
Customer-Oriented Applications	In-premises Devices for Energy Usage Data	High	Customer awareness of appliance energy usage should help drive conservation.
	Customer Web Portal for Energy and Cost Data	High	Customer awareness of appliance energy usage should help drive conservation.
	Outage Notification to Customer	Medium	Near real-time and even after the fact customer knowledge of outage information will allow customers to better assess basement flooding, food spoilage, etc.
	Government and Third Party Use of Customer Data	Medium	Opens up several data privacy issues.
Demand Response	Pricing Information to In-premise Devices	Medium	May be viable with proper technology and communications but present price differentials make for a difficult cost benefit realization.

	Direct Load Control	Low	Not a new technology. This has been available for many years.
	System Frequency Signal to Customer Load Control Devices	Low	Probably more applicable to large scale energy storage devices.
	Systems Renewable Output to Customers	Low	
Distribution Automation	Automatic Circuit Reconfiguration	High	Will have impact on SAIFI.
	Improved Fault Location	High	Will have impact on CAIDI.
	Dynamic System Protection for Two-way Power Flows and Distributed Resources	Low	Most present inverter type distributed resources cannot continue to operate when source is loss. As devices become able to island, this will become a larger issue.
	Dynamic Volt/Var Management	High	Provides for System Optimization, Energy Efficiency and Peak Shaving.
	Conservation Voltage Optimization	High	Provides both Energy Efficiency and Peak Shaving.
Asset/System Optimization	Enhanced System Modeling and Planning	High	With the flood of system data that will be coming with the installation of more and more smart devices, the need to have an accurate system model will be required to allow for data analysis to provide actionable information to the system operators.
	Asset Sizing Optimization	High	Having additional asset loading information will allow for better investment allocation.
	Asset Condition Monitoring	Medium	Ability to remotely determine asset condition needs to be further evaluated.
Distributed Resources	Customer Distributed Resource Integration	Low	Will depend on penetration rates.
	Coordinated Management of Distributed Resources	Low	Will depend on penetration rates.
	Electric Vehicles: Optimized Charging	Medium	Most of this benefit can be driven with appropriate rates.
	Dispatch of Electric Vehicle Storage	Low	Additional cycling of battery may be problematic.

Detroit Edison

	Application	Priority Rating	Comments
AMI Applications	Core AMI Functions	High	Clear, quantifiable, operational benefits.
	Remote Connect/Disconnect	High	Clear, quantifiable, operational benefits.
	Outage Management Support	High	Helpful in verifying restoration.
	Power Quality/Voltage Monitoring at the Meter	Medium	Useful in verifying voltage changes resulting from automated system actions like VVO.
	Customer Prepayment Utilizing AMI	High	Significant Customer Satisfaction Opportunity.
Customer-Oriented Applications	In-premises Devices for Energy Usage Data	Medium	Benefits will be proven as part of DOE project.
	Customer Web Portal for Energy and Cost Data	High	Can help customer modify behavior either manually or automated via IHD.
	Outage Notification to Customer	Medium	Under consideration.
	Government and Third Party Use of Customer Data	Low	Logistically costly, legal issues, customer must approve release to any third party.
Demand Response	Pricing Information to In-premise Devices	Medium	From web portal through the internet, will be part of our DOE project.
	Direct Load Control	Low	Currently have active A/C and Water Heating program via radio.
	System Frequency Signal to Customer Load Control Devices	Low	Would more likely use existing interruptible load programs.
		Low	Not at the present time.

Distribution Automation	Automatic Circuit Reconfiguration	High	Will reduce CAIDI.
	Improved Fault Location	High	Will reduce CAIDI.
	Dynamic System Protection for Two-way Power Flows and Distributed Resources	Low	Current DG is islanded.
	Dynamic Volt/Var Management	High	More granular control of voltage and power factor during heavy load periods.
	Conservation Voltage Optimization	Low	Risk to customer equipment.
Asset/System Optimization	Enhanced System Modeling and Planning	High	Internal process changes necessary to maintain and sustain accurate detailed system model.
	Asset Sizing Optimization	High	More detailed load data can extend asset life based on actual duty cycle.
	Asset Condition Monitoring	Medium	Will start with high value assets like substation transformers, cost may be an issue.
Distributed Resources	Customer Distributed Resource Integration	Low	Equipment cost may limit customer participation.
	Coordinated Management of Distributed Resources	Low	Already have an active DR control center.
	Electric Vehicles: Optimized Charging	Medium	Will be driven primarily by pricing.
	Dispatch of Electric Vehicle Storage	Low	Customer acceptance may be an issue.

Indiana - Michigan Power

	Application	Priority Rating	Comments
AMI Applications	Core AMI Functions	High	Direct benefit in reduced field trips more readily quantifiable.
	Remote Connect/Disconnect	High	Direct benefit in reduced field trips more readily quantifiable.
	Outage Management Support	High	Direct benefit in reduced field trips more readily quantifiable.
	Power Quality/Voltage Monitoring at the Meter	Medium	PQ monitoring can be useful at the meter, but capability is limited in voltage monitoring; momentary data availability is most useful.
	Customer Prepayment Utilizing AMI	Low	Good potential for customer benefit but difficult to implement for utilities and integration into existing billing systems could be costly.
Customer-Oriented Applications	In-premises Devices for Energy Usage Data	Medium	Benefit difficult to quantify due to customer active participation requirement.
	Customer Web Portal for Energy and Cost Data	Medium	Less costly option to inform customer using existing internet connection.
	Outage Notification to Customer	Medium	Still gauging customer interest via a text message pilot.
	Government and Third Party Use of Customer Data	Low	Customer release required.
Demand Response	Pricing Information to In-premise Devices	Medium	Benefit difficult to quantify due to customer active participation requirement.
	Direct Load Control	Medium	Potentially most cost effective if future supply side issues are present.
	System Frequency Signal to Customer Load Control Devices	Low	Potential higher in the future if future supply side issues are present.
	Systems Renewable Output to Customers	Low	No offerings currently planned.

Distribution Automation	Automatic Circuit Reconfiguration	Medium	Direct benefit in reduced field trips more readily quantifiable; reliability benefit is valuable but tough to quantify.
	Improved Fault Location	Medium	Direct benefit in reduced field trips more readily quantifiable; reliability benefit is valuable but tough to quantify.
	Dynamic System Protection for Two-way Power Flows and Distributed Resources	Low	Current distribution system is radically designed, more so in rural areas, but urban areas have more potential for this application but capacity constraints limit the benefit.
	Dynamic Volt/Var Management	High	Distribution circuit optimization can reduce energy losses and improve asset utilization.
	Conservation Voltage Optimization	High	Cost effective means to gain predictable energy reductions beyond the customer's meter with no customer involvement required.
Asset/System Optimization	Enhanced System Modeling and Planning	Medium	More detailed data can yield better and more efficient planning but IT requirement could be costly to implement.
	Asset Sizing Optimization	Medium	More detailed data can yield better and more efficient planning but IT requirement could be costly to implement.
	Asset Condition Monitoring	High	Direct benefit in reduced field trips for routine maintenance monitoring and system condition assessment.
Distributed Resources	Customer Distributed Resource Integration	Medium	Low actual customer interest at present.
	Coordinated Management of Distributed Resources	Medium	Current cost of technologies still too high for widespread adoption.
	Electric Vehicles: Optimized Charging	Medium	Potential for near term need if PEV market takes hold which creates higher risk for local distribution facilities.
	Dispatch of Electric Vehicle Storage	Low	Battery technology for PEVs currently has limitations for this use.

Five Lakes Energy and Next Energy

	Application	Priority Rating	Comments
AMI Applications	Core AMI Functions	High	Marginal justification without time-varying rates. High priority for larger C&I, medium to low priority for residential and small commercial, limited value if not providing pricing information to in-premise devices.
	Remote Connect/Disconnect	Medium	Cost-saving measure, do if core AMI is done.
	Outage Management Support	Medium	Should mostly be addressed by Distribution Automation sensors.
	Power Quality/Voltage Monitoring at the Meter	Low	Should mostly be addressed by Distribution Automation sensors.
	Customer Prepayment Utilizing AMI	Low	Assumes automatic loss of service, prefer financial incentives.
Customer-Oriented Applications	In-premises Devices for Energy Usage Data	Low	Sustainability of behavioral response to real-time data is questionable.
	Customer Web Portal for Energy and Cost Data	High	Done right, an important aid to EO programs.
	Outage Notification to Customer	Low	Usually know already!
	Government and Third Party Use of Customer Data	High	Important aid to low-income and EO programs.
Demand Response	Pricing Information to In-premise Devices	High	Need to start moving toward real-time pricing, this is necessary prerequisite and fairly cheap for utility, limited value if not moving Core AMI.
	Direct Load Control	Medium	More important when reserves are small.
	System Frequency Signal to Customer Load Control Devices	High	Potentially large improvement in frequency regulation and reduction in reserve requirements; requires national standards.
	Systems Renewable Output to Customers	Low	Feels good but unlikely to make a difference.
Distribution Automation	Automatic Circuit Reconfiguration	High	Significant restoration improvement.
	Improved Fault Location	High	Significant restoration improvement.

	Dynamic System Protection for Two-way Power	Medium	Anti-islanding OK for now, importance grows with distributed generation penetration.
	Flows and Distributed Resources		This should be part of preceding line.
	Dynamic Volt/Var Management	High	Large potential energy and capacity savings.
	Conservation Voltage Optimization	High	Large potential energy and capacity savings.
Asset/System Optimization	Enhanced System Modeling and Planning	Medium	Importance grows with load growth and new investment.
	Asset Sizing Optimization	Low	Importance grows with load growth, new investment, and capacity constraints.
	Asset Condition Monitoring	High	Improve reliability and reduce costs.
Distributed Resources	Customer Distributed Resource Integration	High	Large reduction in transaction and installation costs for distributed renewables.
	Coordinated Management of Distributed Resources	Medium	Not needed until penetration increases a lot.
	Electric Vehicles: Optimized Charging	High	Potential economic development opportunity for Michigan.
	Dispatch of Electric Vehicle Storage	Low	Questionable benefits and acceptance.

APPENDIX I

Generation and Transmission – Bulk Power

Technologies and Deployment Inventory

APPENDIX I: Generation and Transmission – Bulk Power Technologies and Deployment Inventory

MISO

Smart Grid Technologies: Devices and Systems	Installed Smart Grid Technologies
Phasor Devices	
Phasor Data Concentrators	1 phasor data concentrator scanning 180 PMUs across the MISO footprint (under development) interfaced to other PDUs in eastern interconnect.
Existing Systems	
State estimator	State estimator that utilizes input from member utility systems via ICCP as well as key interchange points in eastern interconnects. A new case is generated approximately every 90 seconds.
Security constrained unit dispatch	Dispatch of approximately 2,500 generating units in footprint every 5 minutes based on wholesale markets and reliability constraints.
Wind forecasting	Forecast of wind generation by wind farm every 15 minutes for next period, hour and day

American Transmission Company (ATC):

Smart Grid Technologies – Devices and Systems	What do we currently have in place for the Smart Grid Technologies?
Disturbance Monitoring Equipment	
Sequence of event recorders (SOE)	Many of our RTUs have the capability to provide SOE data but we have not utilized this to date.
Fault Recorders	We have 54 digital fault recorders scattered across our system. 6 of these are located in the UP.
Dynamic Disturbance Recorders (DDR)	Of the 54 DFRs we have in service 18 have

Smart Grid Technologies – Devices and Systems	What do we currently have in place for the Smart Grid Technologies?
	DDR capability.
Phasor Devices	
Phasor Enabled Relays	All of our SEL 400 series relays have PMU capability. We have chosen not to enable the data from our in service line relays but have enabled for most of our cap bank control relays.
Phasor Measurement Units (PMUs)	8 PMUs in the UP with plans to add 2 more as part of our DOE project. By 2013 will have PMUs enabled and providing data from all 345 Kv stations and all significant generating stations in the ATC footprint.
Phasor Data Concentrators (Local and Master)	1 phasor data concentrator scanning 32 PMUs scattered around our facilities in the UP and Wisconsin.
Power Quality and Flow Control	
Flexible AC Transmission Systems (FACTS)	None
Phase Angle Regulators (PAR)	None
Static Var Compensator (SVC) (thyristor devices)	None
Static Synchronous Compensator (STATCOM)	None
Convertible Static Compensator (CSC)	None
Harmonic filter capacitor banks	None
Variable Frequency Transformers (VTF)	None
Phase-shifting Transformers	We have two phase shifting transformers. One of these is operated at 69 Kv in western Wisconsin and the other is operated at 345 Kv in Minnesota.
Switchable Series Reactors	We have ~20 switched reactors on the ATC system. 5 of these are in the UP.
Synchronous condenser	None

Smart Grid Technologies – Devices and Systems	What do we currently have in place for the Smart Grid Technologies?
Thryistor-Switched Capacitor System (TSCS) HVDC Switchable capacitor banks	None We are evaluating the use of a back to back DC system for flow control in a constrained area of our system. We have many (~100) automatically controlled cap banks operated at 69 Kv and 138 Kv on our Wisconsin system. We have ~25 cap banks in the UP but these are not normally on automatic voltage control.
Substation Automation	
Intelligent electronic devices Remote terminal units (RTUs)	3,000+ Intelligent electronic devices Approximately 390 RTUs scanning data from our facilities in the UP and Wisconsin. ~30 of these RTUs are located in the UP.
Transmission Equipment	
Advanced transmission line sensors (tension, thermal) Superconductors and advanced conductors Power Equipment Monitoring	We have one line with line tension monitors in place that could be used for dynamic line rating but that has never been implemented in real time operations. None We are installing transformer monitoring packages to monitor the health of our significant transmission transformers. These packages allow us to monitor oil temperatures as well as neutral currents related to geomagnetic induced currents. We are also installing breaker health monitoring equipment at select substations.
Existing Systems	
Real-time / dynamic transmission ratings systems Special Protection System / Schemes (SPS)	We operate to seasonal limits but do not have truly dynamic ratings in place at this time. We have 7 special protection schemes in service at this time. Two of them are related to facilities in the UP.

Smart Grid Technologies – Devices and Systems	What do we currently have in place for the Smart Grid Technologies?
Advanced relaying systems State estimator	We have a state estimator that utilizes input from our ~390 direct scanned RTUs plus data we receive via [ICCP] data links from other companies and the Midwest ISO. Our model covers portions of the states of Iowa, Minnesota, Wisconsin, Michigan, Illinois, and Indiana. We solve every two minutes and feed the data to contingency analysis applications that also run every two minutes.
Developing Systems	
Wide Area Management Systems (WAMS) Advanced linear / non-linear control systems	None at this time but with the PMU data we'll be scanning we may look to implement something in the next 3-5 years. None

ITC Transmission Company (ITC)/Michigan Electric Transmission Company (METC)

Smart Grid Technologies – Devices and Systems	What do we currently have in place for the Smart Grid Technologies?
Disturbance Monitoring Equipment	
Sequence of event recorders (SOE) Fault Recorders Dynamic Disturbance Recorders (DDR)	All ITC and METC RTUs have SOE Data through the DNP protocol. ITC employs GPS Clocks to time sync data across the entire system. 85 Fault Recorders 10 DDRs
Phasor Devices	
Phasor Enabled Relays Phasor Measurement Units (PMUs) Phasor Data Concentrators (Local and Master)	 8 PMUs 1 PDC
Power Quality and Flow Control	

Smart Grid Technologies – Devices and Systems	What do we currently have in place for the Smart Grid Technologies?
Flexible AC Transmission Systems (FACTS) Phase Angle Regulators (PAR) Static Var Compensator (SVC) (Thyristor devices) Static Synchronous Compensator (STATCOM) Convertible Static Compensator (CSC) Harmonic Filter Capacitor Banks Variable Frequency Transformers (VTF) Phase-shifting Transformers Switchable Series Reactors Synchronous Condenser Switchable Capacitor Banks	 2 Statcom 2 Phase Shifting Transformers 5 Switchable Series Reactors 56 Switchable Capacitor Banks
Substation Automation	
Intelligent electronic devices Remote terminal units (RTUs)	3500+ Intelligent electronic devices 350+ RTUs
Transmission Equipment	
Advanced transmission line sensors (Tension, Thermal) Superconductors and advanced conductors Power Equipment Monitoring	None None 90 Transformer Monitors
Energy Storage	
Control systems Storage devices (Mechanical, Chemical, Thermal)	None
Existing Systems	
Real-time / dynamic transmission ratings systems Special Protection System / Schemes (SPS) Advanced relaying systems State estimators Geographic Information System (GIS) Lightening Tracking System	Ratings based on seasonal forecasts 2 Special Protection Schemes 2200+ Advanced Relaying Systems 1 State Estimator 1 GIS 1 Lightening Tracking System
Advanced Meter Infrastructure (AMI)	
Advanced electric meter (Smart meter) Integrated widgets and modules Communication infrastructure	13 Advance Revenue Meters

Consumers Energy (CE):

Smart Grid Technologies – Devices and Systems	What do we currently have in place for the Smart Grid Technologies?
Disturbance Monitoring Equipment	
Sequence of event recorders (SOE) Fault Recorders	Approximately 200 locations with SOE data 10 stand-alone fault recorders and

Smart Grid Technologies – Devices and Systems	What do we currently have in place for the Smart Grid Technologies?
Dynamic Disturbance Recorders (DDR)	approximately (1,800) protective relays with fault recording capability 2 DDRs
Phasor Devices	
Phasor Enabled Relays Phasor Measurement Units (PMUs) Phasor Data Concentrators (Local and Master)	None
Power Quality and Flow Control	
Harmonic filter capacitor banks	1 harmonic filter bank
Substation Automation	
Intelligent electronic devices Remote terminal units (RTUs)	None Approximately 200 RTUs
Transmission Equipment	
Advanced transmission line sensors (Tension, Thermal) Superconductors and advanced conductors Power Equipment Monitoring	CE monitors its equipment for parameters such as temperature, load, and status with various devices
(Energy Storage	
Control systems Storage devices (Mechanical, Chemical, Thermal)	None
Existing Systems	
Real-time / dynamic transmission ratings systems Special Protection System / Schemes (SPS) Advanced relaying systems State estimators	CE does use communication based relay systems where necessary to provide adequate protection CE has a state estimation system
Energy Storage	
PEVs	3 PEVs
Advanced Meter Infrastructure (AMI)	
Advanced electric meter (Smart meter) Integrated widgets and modules Communication infrastructure	Smart Meters 6,620 installed Gas Comm Modules (24) installed Integrated Widgets and Modules – none Communication infrastructure 21 Data Aggregation Points installed Base Station installed
Power Factor Correction Devices	
Amp Reduction Units kVAR	CE uses power factor correction capacitor banks across its system to manage Var

Smart Grid Technologies – Devices and Systems	What do we currently have in place for the Smart Grid Technologies?
	losses
Distribution Resources	
Behind-the-meter Generation Local storage Commercial/residential solar Small-scale wind	The Company has a number of small generators (owned and contracted) that are not interconnected to the transmission system and are not monitored by the transmission provider. The Company accounts for those generators as behind-the-meter. The Company is part owner and operator of the Ludington Pumped Storage Plant. The Company has contracts to purchase approximately 2MW of photovoltaic solar generation from commercial and residential customers. Additional customers participate in the Company's net metering program with solar generation facilities as well. Some customers participate in the net metering program with small-scale wind generation.
Consumers Electronics	
Compact Fluorescent Light bulbs (CFL) Light-Emitting Diode Lights bulbs (LED) Thermostat ("Smart") Smart Appliances	The Company offered a residential CFL program that provided instant rebates for 2,192,355 bulbs from 2009-2010. The Company also offered high efficiency lighting rebates for business customers and has provided rebates for 707,459 high efficiency bulbs and fixtures from 2009-2010. The Company offered rebates for programmable thermostats, and efficient appliances which may or may not be "Smart".
Distribution System Sensor and Control	
Advanced Reclosers Solid State Transfer Switches Dynamic Reactive Power Compensation Distributed Static Synchronous Compensator (DSTATCOM)	Under-frequency load shedding is installed to meet regulatory requirements. Under-voltage load shedding is used in some cases to prevent inadequate supply to customers following abnormal

Smart Grid Technologies – Devices and Systems	What do we currently have in place for the Smart Grid Technologies?
Advanced/intelligent on-load tap changers for transformers Under-frequency/under-voltage load shedding Fault detection sensing and automated restoration Integrated Colt/Var Control (IVVC)	conditions. A few intelligent switching schemes are used on the distribution system to reduce outage duration and number of customers impacted.
Existing Systems	
Demand Side Management programs	Load Modifying Resource – General Interruptible up to 250 MW
Electric Transportation Loads	
Electric Vehicles (EV/BEV/PEV) (mobile loads) Charging infrastructure (Public/Private)	We have installed 1 (non-smart) TOU meter and 3 electric vehicle charging stations (all public). CE is not including electric vehicle storage capabilities into our planning for load management.
Distributed Energy Resources (DER)	
Residential or community small-scale renewables	The Company contracts with approximately 85 residential customers to purchase approximately 0.5 MW of photovoltaic solar generation. The Company has contracts to purchase small-scale (smaller than 5 MW) renewable supplies from approximately 30 suppliers.
Developing Systems	
Home Area Networks (HAN) Industrial Automation Systems Building Automation Systems (BAS) Advanced Metering Infrastructure with distribution system diagnostics	None (196) ICTs installed for DPP Pilot None The Company currently offers the Retro-Commissioning energy efficiency pilot program for business customers which focus on optimization of their existing BAS systems.

Detroit Energy (DTE)

Smart Grid Technologies – Devices and Systems	Deployed Smart Grid Technologies
Disturbance Monitoring Equipment	
Sequence of event recorders (SOE) Fault Recorders Dynamic Disturbance Recorders (DDR)	Approximately 385 locations with SOE data Approximately 1000 distribution protective relays with fault recording capability

Smart Grid Technologies – Devices and Systems	Deployed Smart Grid Technologies
Substation Automation	
Intelligent electronic devices Remote terminal units (RTUs)	Dissolved Gas Analysis at 2 substations. Approximately 1000 distribution Intelligent electronic devices, some installations employ trip coil and breaker monitoring Approximately 683 RTUs
Transmission Equipment	
Advanced transmission line sensors (Tension, Thermal) Superconductors and advanced conductors Power Equipment Monitoring	DTE monitors its equipment for parameters such as temperature, load, voltage and status with various devices
Energy Storage	
Control systems Storage devices (Mechanical, Chemical, Thermal)	There are no battery storage systems installed and operating today.
Existing Systems	
Real-time / dynamic transmission ratings systems Special Protection System / Schemes (SPS) Advanced relaying systems State estimators	DTE does use communication based relay systems where necessary to provide adequate protection. DTE has a state estimation system.
Energy Storage	
PEVs Super / Ultra Capacitors Aggregated Distributed Storage Liquid metal batteries Distributed Series Impedance (DSI) transmission lines (Smart Wires") Adaptive Relaying	None
Developing Systems	
Wide Area Management Systems (WAMS) Advanced linear / non-linear control systems	None
Advanced Meter Infrastructure (AMI)	
Advanced electric meter (Smart meter) Integrated widgets and modules Communication infrastructure	To date, there are approximately 316,000 installed Itron OpenWay smart meters. DTE has plans to install up to 600,000 smart meters over the next year as part of the SmartCurrents project. This project is in conjunction with the DOE smart grid Investment Grant.
Power Factor Correction Devices	
Amp Reduction Units kVAR	DTE uses capacitor banks across its system to manage Var demand and

Smart Grid Technologies – Devices and Systems	Deployed Smart Grid Technologies
	losses.
Distribution Resources	
Behind-the-meter Generation Local storage Commercial/residential solar Small-scale wind	The Company has a number of small generators (owned and contracted) that are not interconnected to the transmission system and are not monitored by the transmission provider. The Company accounts for those generators as behind-the-meter. The Company is part owner and operator of the Ludington Pumped Storage Plant. As of March 2011; installed capacity (net metered customers) Solar: 2.36 MW (380 customers) Wind: 0.34 MW (43 customer) As of April 2011 the 5MW SolarCurrents customer program is fully subscribed, meaning there is approx. 2.5MW in process of being connected. As of April 2011; the utility has installed/commissioned 3 solar projects equaling 1.056MW.
Consumers Electronics	
Compact Fluorescent Light bulbs (CFL) Light-Emitting Diode Lights bulbs (LED) Thermostat (“Smart”) Smart Appliances	The Company offered a residential CFL program that provided instant rebates for 5,151,025 bulbs from 2009-2010. The Company also offered high efficiency lighting rebates for business customers and has provided rebates for 328,348 high efficiency bulbs and fixtures from 2009-2010. We will be offering 1,050 In Home Displays and 1,050 Programmable Communication Thermostats to residential customers in our AMI service territory in conjunction with our DPP Pilot. We will be offering smart appliances to

Smart Grid Technologies – Devices and Systems	Deployed Smart Grid Technologies
	300 residential customers with AMI. The appliances offered will be washers, dryers, dishwashers and refrigerators These are all ZigBee enabled smart devices.
Distribution System Sensor and Control	
Advanced Reclosers Solid State Transfer Switches Dynamic Reactive Power Compensation Distributed Static Synchronous Compensator (DSTATCOM) Advanced/intelligent on-load tap changers for transformers Under-frequency/under-voltage load shedding Fault detection sensing and automated restoration Integrated Colt/Var Control (IVVC)	Approximately 220 Advanced reclosers (Cooper Form 6 – Triple Single) installed to date. Under-frequency load shedding is installed to meet regulatory requirements. Intelligent switching schemes are used on the distribution system to reduce outage duration and number of customers impacted.
Existing Systems	
Demand Side Management programs	Interruptible Air Conditioning program – Cool Currents of approximately 200 MW. Commercial and Industrial interruptible tariffs totaling another approximate 400 MW's for a total of ~615 MW
Electric Transportation Loads	
Electric Vehicles (EV/BEV/PEV) (mobile loads) Charging infrastructure (Public/Private)	90 plus electric vehicles in the DECo service territory at an average of 300 kWh's per vehicle There are approximately 25 private charging stations installed
Distribution Systems Sensor and Control	
Distribution transformers with phase angle and amplitude control Solid state transformers	None
Distributed Energy Resources (DER)	
Residential or community small-scale renewables	The Company contracts with residential customers to purchase approximately 5 MW of photovoltaic solar generation through our SolarCurrents program. As of March 2011; installed capacity (net metered customers) Solar: 2.36 MW (380 customers) Wind: 0.34 MW (43 customer)

Smart Grid Technologies – Devices and Systems	Deployed Smart Grid Technologies
	As of April 2011 the 5MW solarcurrents customer program is fully subscribed, meaning there is approx. 2.5MW in process of being connected. As of April 2011; the utility has installed/commissioned 3 solar projects equaling 1.056MW
Developing Systems	
Home Area Networks (HAN) Industrial Automation Systems Building Automation Systems (BAS) Advanced Metering Infrastructure with distribution system diagnostics	We will launch a HAN pilot Q1 2012 that will include a Zigbee enabled gateway device that will be the main communication hub between the meter and the in home devices. The in home devices will include IHDs, PCTs and smart appliances.

Wolverine Power Supply Cooperative Inc (WPSCI):

Bulk Power System	
Smart Grid Technologies – Devices and Systems	What do we currently have in place for the Smart Grid Technologies?
Disturbance Monitoring Equipment	
Sequence of event recorders (SOE) Fault Recorders Dynamic Disturbance Recorders (DDR)	Approximately 300 relays with SOE capabilities. (Approximately 75 in BES) Approximately 300 relays with fault recording capabilities. (Approximately 75 in BES) No DDRs
Substation Automation	
Intelligent electronic devices Remote terminal units (RTUs)	Approximately 200 relays with intelligence capabilities. (Approximately 75 in BES) Approximately 55 RTUs (Approximately 10 in BES)

APPENDIX J

Collaborative Definitions

APPENDIX J: Collaborative Definitions

1. AMI Applications
    a. Core AMI Functions
    b. Remote Connect/Disconnect
    c. Outage Mangement Support
    d. Power Quality / Volatge Monitoring at the meter
    e. Customer Prepayment utilizing AMI

2. Customer-Oriented Applications
    a. In-premises Devices for Energy Usage Data
    b. Outage Notification to Customer
    c. Government and Third Party Use of Customer Data

3. Demand Response
    a. Pricing Information to In-premise Devices
    b. Direct Load Control
    c. System Frequency Signal to Customer Load Control Devices
    d. Systems Renewable Output to Customer

4. Distrubution Automation
    a. Automatic Circuit Reconfiguration
    b. Improved Fault Location
    c. Dynamic System Protection for Two-way Power Flows and Distributed Resources
    d. Dynamic Volt/Var Management
    e. Conservation Voltage Optimization

5. Asset / System Optimization
    a. Enhanced System Modeling and Planning
    b. Asset Sizing Optimization
    c. Asset Condition Monitoring

6. Distributed Resources
    a. Customer Distributed Resource Integration
    b. Coordinated Management of Distributed Resources
    c. Electric Vehicles: Optimized Charging
    d. Dispatch of Electric Vehicle Storage

7. Transmission
    a. Wide Area (Phasor) Measurement

Definitions

Core AMI

AMI metering allows the utility to establish a two-way connection to the premises metering device and supports time differentiated interval measurement. These new measurement capabilities allow for new rate structures and can support increased customer awareness of energy usage. Data from AMI meters can be used by the utility to support other smart grid applications. AMI meters can optionally include a customer owned network interface to support demand response applications and increased customer awareness of energy usage, prices and other information.

Remote connect/disconnect

Remote connect/disconnect devices whether located in AMI meters or as a separate device are equipped with remotely operable integrated service switches. The utility can open or close the switch by sending a signal to the device. The utility may operate the switch for purposes of customer request, pre-payment services, non-payment, safety or reconnection after payment is received.

Outage management support

AMI Meters can report power outage and power restoration messages to the utility. This functionality will allow the utility to determine the scope and location of an outage, to improve outage response time, and to verify that all customer outages are restored.

Power quality/voltage monitoring at meter

An AMI meter can provide the utility with an extensive view of voltage levels throughout the distribution system and may provide other measurements that allow the utility to evaluate system harmonics and power factor. The ability to achieve the benefits for this application largely depend on the capability of the meter to perform measurements that are not normally associated with traditional metering functionality and the network capacity to transport the additional data.

Prepayment with AMI

A prepayment program provides customers with an option to purchase electricity in advance of its use by purchasing a specified amount of electricity at a specified price. Such programs typically include automatic disconnection of service when the customer's usage exceeds the amount of electricity purchased. Prepayment can serve as an alternative to deposit requirements for utility service, and may reduce the utility's credit and collection costs, as well as provide a structure to assist customers in reducing their electricity usage.

In-premise devices for energy usage data

In-premise devices receive and display energy usage information to customers. This information can be used by customers to manage their energy consumption. AMI meters can be used to communicate energy usage data to in-premises devices using a communications network (e.g. HAN). Communication to in-premises devices could be accomplished with technologies such as cellular networks, traditional wired phone services, broadband internet connections or private networks.

Outage notification to customer

An enhanced outage management system integrated with AMI, can inform customers through automated emails, web portals, social networking, text messages and phone calls of existing outages and estimated restoration times.   Customers voluntarily receiving this information can make better decisions on how to respond to the outages.

Government and third party use of customer data

This application is a high level representation of scenarios allowing customers to choose to share all or a portion of their energy usage data, outage status, rate plans or energy cost data with third parties. The customer should control access to their data and determine which third parties would be able to view specific types of information. Customers would also be informed of how third parties intend to use the data.

Pricing info to in-premise devices

Demand response generated by price signals allows the customer control of how they wish to participate during periods when energy costs vary. Price based demand response requires that the customer has more real time information to automate the response. This application assumes that price based demand response can be as simple as a fixed schedule, tiered, time of use rate, critical peak pricing and critical peak rebates or a more dynamic interval based real time price rate. More dynamic rate structures may require additional automation of in-premises devices to maximize the application's benefits.

Direct load control

Demand response can be provided by installing load control devices that receive a signal from the utility or third party to reduce load at the controlled device. Customers may be able to override the direct load control request. Two-way communication ensures that intended devices get the direct control request and respond accordingly and allow the requester of the load control event know if a customer opted out.

System frequency signal to customer load control devices

Customer devices or appliances equipped with electric system frequency sensors can detect changes in the electric system frequency that indicate instability due to insufficient generation and drop load. Frequency sensing can be added to existing appliances or for very low cost be incorporated into future appliance designs. Customers could provide frequency response load reduction to utilities or third parties in exchange for a financial benefit.

Systems renewable output to customers

Customer's displays or devices could receive information about the current output of the electric system's renewable generation. The customer can choose to reduce their energy usage or program devices to use less energy when renewable output is low. Information about the system's renewable output is provided by the Regional Transmission Operator or the utility.

Automatic circuit reconfiguration

A distribution system can use communicating switches and circuit reclosers to reconfigure the distribution system during an outage, degraded circuit condition or load balancing. For example, an automatic reconfiguration allows for a portion of customers who would traditionally suffer a distribution level outage to have their power restored in a few seconds. The system may also provide better information to the utility about the location of faults and the current configuration of the distribution system.

Improved fault location

Additional distribution sensors with network communication capability may be installed to improve the utility's ability to detect the location of system faults. The fault sensors can report to the utility distribution management system and help pinpoint the location of system faults.

Dynamic system protection for two-way power flows and distributed resources

Most distribution systems are designed primarily for one-way power flow to customer end points. As distributed resources become more prevalent, the distribution system will require sensing of local system conditions and distributed generation resources such as battery, photo voltaic and wind. Automated control signals will adjust line devices and distributed resource output to maintain safety and stability of the distribution system within the affected area.

Dynamic Volt/Var management

The smart distribution system can monitor voltage and power quality at multiple points throughout the system, including at customer AMI meters. This application would include the use of voltage and power quality monitoring devices along with capacitor bank and load tap changing transformer controls to control the voltage and reactive power on the system. System benefits of volt/var management include reliability and voltage stabilization. While AMI meters would likely be used to provide voltage measurements at points throughout the distribution system, an AMI system is not required for this application and voltage measurements may be provided by sensing devices installed on the distribution system specifically for this application.

Conservation voltage optimization

This application is an extension of Dynamic Volt/Var Management. The smart distribution system can sense and control the voltage level at finer granularity across the entire distribution circuit and down to extended laterals. Utilities can maintain a lower regulated voltage across the distribution circuit thus providing reduced energy consumption and increasing system efficiency. This application would include the use of voltage and power quality monitoring devices along with capacitor bank and load tap changing transformer controls to maintain the voltage and reactive power on the system for energy conservation. This application could be used in a near real-time manner to reduce usage during periods of high energy costs, low load conditions or to alleviate system congestion.

Enhanced system modeling and planning

Data from AMI meters and distribution system sensors provide the utility information to validate system models and efficiently plan for system upgrades, new customer loads and distributed resource integration. When sufficient numbers of sensors are in place and data are available, some traditional power flow models can be updated with true representations of the system during diverse operational conditions.

Asset sizing optimization

Data provided by AMI meters and new distribution system sensing devices provide the utility with the ability to accurately determine loading and view operational attributes of distribution system components over time. The increase in system visibility allows the utility to correctly size system components such as distribution transformers and replace them based on actual operating conditions. This application is used operationally in a more dynamic manner than the above long term system modeling and planning application.

Asset condition monitoring

Distribution and transmission system sensors that detect temperature and battery condition allow the utility to monitor the real time performance and health of system components. The utility can take corrective action at the appropriate time resulting in increased system reliability, operational efficiency and optimized equipment maintenance cycles.

Customer distributed resource interconnection

Customer owned generation resources can provide power into the distribution system and help defer construction of new generation or increase the use of renewable energy. The smart grid can facilitate the interconnection of customer generation and storage by providing technical support and through the implementation of other applications that induce the installation of distributed resources. Customer owned generation and storage is possible today, but AMI and other smart grid applications could allow customers to better utilize their own generation and storage and potentially to provide power back to the electric system.

Customer owned distributed resources are currently used by some customer groups under existing technologies. This application is focused on using other smart grid applications to increase the deployment of distributed resources.

Coordinated management of distributed resources

Permitting the utility to communicate with customer or utility owned generation such as wind, solar or battery can allow the utility to better manage the distribution system. A utility system that is aware of the operating condition and output of distributed resources can provide better system protection and reliability. This application envisions a scenario where utilities or third parties enroll customers with distributed resources in a voluntary program that allows the utility or third party to operate the customers' generation based on market conditions or for purposes of reliability. This application includes both small and large scale generation and storage devices.

Electric vehicles: optimized charging

High market penetration of electric vehicles will add significant load to specific areas of the distribution system which could be managed through the use of smart charging systems. Dense localized deployment of electric vehicles and charging stations may strain local distribution system devices. Smart charging systems include features such time delayed charging, time-of-use controls, pricing signal controls, critical peak controls and automated load shed controls.

Dispatch of electric vehicle storage

Electric vehicles may provide stored energy as a backup resource when system and market conditions are appropriate. Technology controls are required to enable the two-way power flow of energy from the vehicle batteries through the charging station into the distribution grid. Near real-time energy flow will either be locally controlled or dispatched and actively managed by the electric utility control center. Vehicle-to-grid (V2G) dispatch may have a difficult economic case using available technology based on the increased wear on a vehicle's battery from a greater number of charge/discharge cycles. In addition, V2G would be subject to trade-off evaluation by customers choosing between maintaining vehicle charge levels and obtaining market value for the stored electricity.

Wide area phasor measurement

Improved communications and sensors allow better visibility and decision making for transmission system operations. Phasor measurement units in substations can measure system phase angles 30 times per second. The data is transmitted back to a control center to determine phase angle differences at various points of the grid. The phase angle differences provide improved situational awareness and should improve grid stability. The technology for this application is mature and wide area measurement devices and systems are being increasingly deployed.

APPENDIX K

Collaborative Recommendations

APPENDIX K: Collaborative Recommendations

Regulatory and Policy

Deployment & Customer Protections

- Utilities to provide a smart grid vision statement.
- Utilities to provide a deployment plan that documents a smart grid roadmap that is consistent with their vision statement.
- Utilities should select meters that:
    - use internal component designs that detect outside intrusions and enable isolation of affected equipment,
    - feature automated key exchange and secure firewalls, and
    - follow recommended meter capability principles outlined in the Deployment and Customer Protection section.
- Utilities and vendors should comply with national standards for data and operational procedure security.
- Utilities should create and implement customer education plans.
- The Commission should provide policy about customer usage data for utilities that:
    - standardize the protection of AMI customer usage data for utilities. Existing retail open access tariffs should be referenced as they apply to non-smart grid applications, and
    - define permissible and non-permissible use of AMI customer data for utility operations.
- Utilities should develop a plan for customer usage data that:
    - establishes a procedure for customer data breach including notification procedure for both customer & the Commission,
    - establishes how and at what cost customer data can be shared with others once customer permission has been obtained, and
    - explores the issue of permitting third party purchase of aggregated data.
- Administrative rules should be reviewed or established for:
    - remote shut-off and restoration, and
    - prepayment options.
- Utilities should continue to assess prepayment pilot projects and determine customer value.

- Qualitative and quantitative metrics should be established to measure customer benefit resulting from smart grid deployment.

Cost Benefit

- Utilities should utilize the cost benefit framework recommended by the Cost Benefit subgroup.
- Utilities should consider complex and difficult to quantify costs and benefits.
- Utilities and MPSC should periodically evaluate costs and benefits throughout deployment.

Cost Recovery

- "Pilot" size & scope perimeters need to be defined.
- "Full deployment" needs to be defined, including clarification of conditions utilities need to meet referenced in the cost recovery policy principles in Commission Order in U-16191.
- Appropriate treatment of stranded assets that occur during grid modernization deployment needs to be clarified.
- Address smart grid cost recovery using traditional rate based recovery mechanisms (no riders or surcharges).
- Utilities and MPSC need to collectively establish clear, concise reporting requirements designed to measure customer benefit.

Customer Programs and Communications

- Increase customer awareness using the newly developed communication framework.
- Create and implement customer education plans, which align to the overall SG Communication Guidelines, that include:
- Understand the customers including preferred modes of communication and interests related to smart grid.
- Stakeholders should work to design concise metrics measuring customer communication efforts, education programs, and engagement results that will result in:

    MI customers, utility employees and other stakeholders are well informed, aware and accepting of the need for continuous improvement of the electric grid.

Distribution and Grid Applications

Short Term

- Develop a smart grid vision along with a fair and reasonable regulatory framework for smart grid projects in Michigan. This regulatory framework should protect customers, enable and facilitate utility investment in new technology, and be sustainable over the long term with minimal need for revisions. Both the vision and the underlying regulatory policies should be structured such that the timing of smart grid investments does not cause excessive burden on customers from the amount of associated upfront capital expenditures, and that investments are timed with consideration toward the implementation of new environmental regulations that may require other significant upfront capital expenditures.
- In order to help quantify costs and benefits associated with certain smart grid applications, guide business case formation, and assist with regulatory review of smart grid proposals, all utilities planning to deploy or currently deploying smart grid technology should consider various pilots across all customer classes. While not all utilities will be able to pilot each of these applications, the pilots should include volt/var control, conservation voltage optimization, other distribution automation applications, and advanced use of smart meter capabilities including but not limited to:
    - Multiple pricing schemes targeted at assessing demand side energy management behavior.
    - Pricing publication with customer web access and in-premise system access.
    - Meter to in-premise device interoperability.
    - Interval usage metering.
    - Expanded kVA/Power Factor metering.
    - Remote meter reading.
    - Accurate and usable billing information based on interval usage and pricing.
    - Remote connect/disconnect.
    - Outage management support.
    - Customer and Customer Authorized third party data access.
    - Reliability and cyber-security.

- Once any necessary piloting is concluded, utilities should offer various dynamic pricing programs to applicable customer classes when and where it is cost-effective, beneficial, and accepted by those customers.
- Revise current technical specifications to include advanced meters, specifically addressing: a) hardware defect rates; b) minimum functionality; c) interoperability standards; and d) meter accuracy.

Long Term

Projecting the future of any technology is difficult, and the smart grid is no different. All stakeholders have provided a list ranking various smart grid applications for future deployment. However, these are only projections. Any number of unforeseen factors could cause a change in ranking and the rationale behind it. In like manner, attempting to articulate a set of long-term recommendations for smart grid deployment in Michigan is equally daunting due to a high level of uncertainty. A set of possible recommendations were proposed by various workgroup stakeholders to address the long-term potential of smart grid in Michigan. Among the ideas and proposals:

- Ensure that all smart grid applications, to the extent they are found cost-effective within the prescribed regulatory framework but respective to each utility, are enabled in all Michigan utilities deploying smart grid by a certain date. This includes those applications associated with distribution automation as well as distributed resources. This recommendation addresses the "implementation" component of the smart grid effort.
- By a certain date in the future, have all Michigan utilities achieve certain performance targets, selecting targets that are smart grid specific. Examples of such targets could include: automatically isolate main line faults and restore unaffected main line portions of the circuit for all main line faults on circuits that have electrical ties to other circuits; reduce greenhouse gas emissions through voltage optimization and distributed resource integration by a specific year; and improve Michigan utilities' generation and distribution efficiency by a percentage to be defined by the stakeholders through voltage optimization and demand response. This recommendation fits into answering the question of "why implement smart grid?"
- Continue moving toward physical completion of distribution system communication channels, emphasizing functions that provide accurate system-wide information, increasing grid

stability and improve restoration abilities: Advanced metering infrastructure, SCADA, and Distribution automation. Should be integrated to increase and improve available information.

- The State of Michigan, Michigan electric utilities, automobile manufacturers (presumably including Chrysler, Ford, and General Motors), vehicle charging companies, battery technology companies, US DOE, US DOT, US EPA, and all relevant standards groups should create a research and development plan in Michigan for PEV-smart grid integration. This should include charging process responsiveness to time-varying pricing, system frequency responsiveness, and direct load control signals; sub-metering and AMI integration; response to power outage and restoration events; and vehicle battery storage as a distributed resource. The plan would address standards, implementation technologies, user behavior, and analysis of power system effects. Utilities should be allowed to recover their share of the expense of developing such a plan. This recommendation addresses the future role that a smart grid could serve in the automotive industry, an industry that is central to Michigan's economy.

Generation and Transmission

As mentioned earlier in this report, the members of the Generation and Transmission Workgroup believe the realization of smart grid's promise depends upon long-term planning strategies with the integration of all utility partnerships and resources in this process.

The applicability of the following recommendations should not be interpreted as being limited only to the Generation and Transmission section of this report. Generation and transmission is only one piece of smart grid. The usefulness of these suggestions cross workgroup lines and contribute to a cohesive, collaborative approach to this all-encompassing concept known as smart grid. (Unless otherwise noted, the following statements may be considered a consensus position of the workgroup.)

MISO

- Identify specific opportunities within the MISO market structure to reduce system costs and increase reliability, e.g., higher frequency dispatch.

- Conduct a cost benefit study of real-time market monitoring to determine if the capital outlay necessary to receive and analyze data continuously (rather than the current 15 minute model), will be justified by identification of market design flaws that create inefficient or perverse incentives.

Transmission Operators

- Coordination and cooperation with MISO and North American Synchrophasor Initiative (NASPI).
- Work closely with MISO on their synchrophasor implementation project to provide data and to help develop applications that use the data.
- Work closely with the NASPI group to stay current on developments nationally and world-wide.
- Improve reliability by continuing to install new advanced transmission system protection systems and advanced intelligent electronic devices.
- Improve visibility and security of the transmission system by upgrading telecommunication infrastructure and monitoring capabilities.

MPSC

- Research and author white papers of interest to Commissioners,
- Review the pros and cons of different generation sources including the integration of renewable energy sources,
- Consider distributed generation options including the impact of small scale solar and wind,
- Target areas of greatest benefit to utilities and other stakeholders, including the impact of renewable energy sources and demand response initiatives, and
- Evaluate cost benefit considering impact on transmission and generation operators, customers and other stakeholders.

General

- Coordinate yearly update of the smart grid technology deployment inventory, with updates from transmission operators and utilities.
- Analyze and develop long-term implementation strategy for the state,

- Develop a strategic plan to optimize devices to the greatest advantage/lowest cost.
- Upgrade equipment and practices to continue improving reliability and system visibility. Continually analyze new technology for best practices.
- Gain efficiency in dealing with unplanned outages using appropriate reliability indices such as Loss of Load Probability (LOLP), Loss of Load Expectation (LOLE), Loss of Load Frequency (LOLF) and Expected Unserved Energy (EUE).

Codes and Standards

- Establish a repository of references for codes and standards (could be formal document or just a reference to NIST).
- Active participation and or monitoring in the following groups: SGIP, Open SG, NIST, and other significant standard development. Organizations such as IEEE, ANCI, ZigBee, NAESB, etc. with monthly collaboration with our involvement.
- Drive structural changes needed within SGIP to address the reliability and implementation impacts that standards could have on the utility industry.
- Establish positions on critical codes and standards issues that represent the stakeholders in the Collaborative (i.e., RF, privacy).
- Remain in compliance of industry best practices and standards as identified for smart grid interoperability.
- Evaluate the codes and standards technology required for the interoperability of communication and distribution system networks.

APPENDIX L

Mapping Requirements

APPENDIX L: Mapping Requirements

Core AMI

Application	Domain	Layers	Requirements	Standards
AMI Applications				
Core AMI Functions	Customer, Operations	application	IEEE 2030, NISTIR 7628, IEC PAS 62559, IEC PAS 62559, AMI ENT, SG Net, AEIC Guidelines v2.0, ASAP-SG Security Profile for Advanced Metering Infrastructure, NEMA SG-AMI 1-2009	ANSI C12.19, ANSI C12.18, ANSI C12.21, ANSI C12.22, SNMP v3, IEC 61968 Part 9
		networking	IEEE 2030, NISTIR 7628, IEC PAS 62559, IEC PAS 62559, SG Net, ASAP-SG Security Profile for Advanced Metering Infrastructure	IETF RFC 791 (IPv4), IETF RFC 2460 (IPv6), 6LOWPAN, ANSI C12.22, IETF RFC 6272
		physical	IEEE 2030, NISTIR 7628, IEC PAS 62559, IEC PAS 62559, SG Net	IEEE 802 series: IEEE 802.11, 802.15.4, 802.16, IPOS DVB S2, CDMA 2000 series, TIA HRPD and MPS series, 1X-EV-DO, EDGE, UMTS, HSPA+, LTE, ETSI GMR-1 3G

Remote Connect/Disconnect

Application	Domain	Layers	Requirements	Standards
AMI Applications				
Remote Connect/Disconnect	Customer, Operations, Service Provider	application	IEEE 2030, NISTIR 7628, IEC PAS 62559, IEC PAS 62559, AMI ENT, SG Net, AEIC Guidelines v2.0, ASAP-SG Security Profile for Advanced Metering Infrastructure	ANSI C12.19, ANSI C12.18, ANSI C12.21, ANSI C12.22, SNMP v3, SNMP v3, IEC 61968 Part 9
		networking	IEEE 2030, NISTIR 7628, IEC PAS 62559, IEC PAS 62559, SG Net, ASAP-SG Security Profile for Advanced Metering Infrastructure	IETF RFC 791 (IPv4), IETF RFC 2460 (IPv6), 6LOWPAN, ANSI C12.22, IETF RFC 6272
		physical	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	IEEE 802 series: IEEE 802.11, 802.15.4, 802.16, IPOS DVB S2, CDMA 2000 series, TIA HRPD and MPS series, 1X-EV-DO, EDGE, UMTS, HSPA+, LTE, ETSI GMR-1 3G

Outage Management Support

Application	Domain	Layers	Requirements	Standards
AMI Applications				
Outage Management Support	Operations, Distribution, Customer	application	IEEE 2030, NISTIR 7628, IEC PAS 62559, AMI ENT, SG Net, ASAP-SG Security Profile for Advanced Metering Infrastructure	ANSI C12.19, ANSI C12.18, ANSI C12.21, ANSI C12.22, SNMP v3, IEC 61968 Part 9
		networking	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net, ASAP-SG Security Profile for Advanced Metering Infrastructure	IETF RFC 791 (IPv4), IETF RFC 2460 (IPv6), 6LOWPAN, ANSI C12.22, IETF RFC 6272
		physical	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	IEEE 802 series: IEEE 802.11, 802.15.4, 802.16, IPOS DVB S2, CDMA 2000 series, TIA HRPD and MPS series, 1X-EV-DO, EDGE, UMTS, HSPA+, LTE

Power Quality/Voltage Monitoring at Meter

Application	Domain	Layers	Requirements	Standards
AMI Applications				
Power Quality/Voltage Monitoring at the Meter	Customer	application	IEEE 2030, NISTIR 7628, IEC PAS 62559, AMI ENT, SG Net, AEIC Guidelines v2.0, ASAP-SG Security Profile for Advanced Metering Infrastructure	ANSI C12.19, ANSI C12.18, ANSI C12.21, ANSI C12.22, IEEE 1159, IEC 61000-4-30, SNMP v3, IEC 61968 Part 9
		networking	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net, ASAP-SG Security Profile for Advanced Metering Infrastructure	IETF RFC 791 (IPv4), IETF RFC 2460 (IPv6), 6LOWPAN, ANSI C12.22, IETF RFC 6272
		physical	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	IEEE 802 series: IEEE 802.11, 802.15.4, 802.16, IPOS DVB S2, CDMA 2000 series, TIA HRPD and MPS series, 1X-EV-DO, EDGE, UMTS, HSPA+, LTE, ETSI GMR-1 3G

Prepayment with AMI

Application	Domain	Layers	Requirements	Standards
AMI Applications				
Customer Prepayment Utilizing AMI	Customer, Service Provider, Operations	application	Open HAN, IEEE 2030, NISTIR 7628, IEC PAS 62559, AMI ENT, SG Net	SEP 2.0, NAESB WEQ19 & REQ18, SNMP v3, IEC 61968 Part 9
		networking	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	IETF RFC 791 (IPv4), IETF RFC 2460 (IPv6), 6LOWPAN, IETF RFC 6272
		physical	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	IEEE 802 series: IEEE 802.11, 802.15.4, 802.16, IPOS DVB S2, CDMA 2000 series, TIA HRPD and MPS series, 1X-EV-DO, EDGE, UMTS, HSPA+, LTE, ETSI GMR-1 3G

In-Premises Devices for Energy Usage Data

Application	Domain	Layers	Requirements	Standards
Customer-Oriented Applications				
In-premises Devices for Energy Usage Data	Customer	application	Open HAN, IEEE 2030, NISTIR 7628, IEC PAS 62559, AMI ENT, SG Net	SEP 1.X, SEP 2.0, NAESB WEQ19 & REQ18, SNMP v3, IEC 61968 Part 9
		networking	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	SEP 1.X, IETF RFC 791 (IPv4), IETF RFC 2460 (IPv6), 6LOWPAN, IETF RFC 6272
		physical	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	IEEE 802 series: IEEE 802.11, 802.15.4, 802.16, IPOS DVB S2, CDMA 2000 series, TIA HRPD and MPS series, 1X-EV-DO, EDGE, UMTS, HSPA+, LTE, SAE J1772, SAE J2847/1-3, IEEE 1901, ITU-T G.9972 , ISO/IEC 12139-1, ETSI GMR-1 3G

Outage Notification to Customer

Application	Domain	Layers	Requirements	Standards
Customer-Oriented Applications				
Outage Notification to Customer	Operations, Customer, Service Provider	application	Open HAN, IEEE 2030, NISTIR 7628, IEC PAS 62559, AMI ENT, SG Net	SEP 1.X, SEP 2.0, SNMP v3, IEC 61968 Part 9
		networking	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	SEP 1.X, IETF RFC 791 (IPv4), IETF RFC 2460 (IPv6), 6LOWPAN, IETF RFC 6272
		physical	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	IEEE 802 series: IEEE 802.11, 802.15.4, 802.16, IPOS DVB S2, CDMA 2000 series, TIA HRPD and MPS series, 1X-EV-DO, EDGE, UMTS, HSPA+, LTE

Sharing Customer Data

Application	Domain	Layers	Requirements	Standards
Customer-Oriented Applications				
Sharing of Customer Data	Customer, Operations, Service Providers	application	Open HAN, IEEE 2030, NISTIR 7628, IEC PAS 62559, AMI ENT, SG Net	NAESB WEQ19 & REQ18, SNMP v3, IEC 61968 Part 9
		networking	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	SEP 1.X, IETF RFC 791 (IPv4), IETF RFC 2460 (IPv6), 6LOWPAN, IETF RFC 6272
		physical	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	IEEE 802 series: IEEE 802.11, 802.15.4, 802.16, IPOS DVB S2, CDMA 2000 series, TIA HRPD and MPS series, 1X-EV-DO, EDGE, UMTS, HSPA+, LTE, ETSI GMR-1 3G

Pricing Information to in-premise Devices

Application	Domain	Layers	Requirements	Standards
Demand Response				
Pricing Information to In-premise Devices	Customer, Operations, Distribution	application	Open ADR IEEE 2030, NISTIR 7628, IEC PAS 62559, AMI ENT, SG Net	SEP 2.0 , Open ADR, NAESB WEQ19 & REQ18, SNMP v3, IEC 61968 Part 9
		networking	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	SEP 1.X, SEP 2.0, IETF RFC 791 (IPv4), IETF RFC 2460 (IPv6), 6LOWPAN, IETF RFC 6272
		physical	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	IEEE 802 series: IEEE 802.11, 802.15.4, 802.16, IPOS DVB S2, CDMA 2000 series, TIA HRPD and MPS series, 1X-EV-DO, EDGE, UMTS, HSPA+, LTE, ISO/IEC 12139-1, ETSI GMR-1 3G

Direct Load Control

Application	Domain	Layers	Requirements	Standards
Demand Response				
Direct Load Control	Customer, Operations, Distribution	application	Open ADR IEEE 2030, NISTIR 7628, IEC PAS 62559, AMI ENT, SG Net	SEP 2.0 , Open ADR, SNMP v3, IEC 61968 Part 9
		networking	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	SEP 1.X, SEP 2.0, IETF RFC 791 (IPv4), IETF RFC 2460 (IPv6), 6LOWPAN, IETF RFC 6272
		physical	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	IEEE 802 series: IEEE 802.11, 802.15.4, 802.16, IPOS DVB S2, CDMA 2000 series, TIA HRPD and MPS series, 1X-EV-DO, EDGE, UMTS, HSPA+, LTE, ISO/IEC 12139-1, ETSI GMR-1 3G

System Frequency Signal to Customer Load Control Devices

Application	Domain	Layers	Requirements	Standards
Demand Response				
System Frequency Signal to Customer Load Control Devices	Customer, Operations, Distribution	application	Open ADR IEEE 2030, NISTIR 7628, IEC PAS 62559, AMI ENT, SG Net	SEP 2.0, SNMP v3, IEC 61968 Part 9
		networking	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	SEP 1.X, SEP 2.0, IETF RFC 791 (IPv4), IETF RFC 2460 (IPv6), 6LOWPAN, IETF RFC 6272
		physical	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	IEEE 802 series: IEEE 802.11, 802.15.4, 802.16, IPOS DVB S2, CDMA 2000 series, TIA HRPD and MPS series, 1X-EV-DO, EDGE, UMTS, HSPA+, LTE, ETSI GMR-1 3G

Renewable Output to Customers

Application	Domain	Layers	Requirements	Standards
Demand Response				
Systems Renewable Output to Customers	Customer, Operations, Service Providers	application	Open ADR IEEE 2030, NISTIR 7628, IEC PAS 62559, AMI ENT, SG Net	SEP 2.0, IEC 61400-25, SNMP v3, IEC 61968 Part 9
		networking	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	SEP 1.X, SEP 2.0, IETF RFC 791 (IPv4), IETF RFC 2460 (IETF RFC 2460 (IPv6)), 6LOWPAN, IETF RFC 6272
		physical	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	IEEE 802 series: IEEE 802.11, 802.15.4, 802.16, IPOS DVB S2, CDMA 2000 series, TIA HRPD and MPS series, 1X-EV-DO, EDGE, UMTS, HSPA+, LTE, ETSI GMR-1 3G

Automatic Circuit Reconfiguration

Application	Domain	Layers	Requirements	Standards
Distribution Automation				
Automatic Circuit Reconfiguration	Distribution, Operations, Transmission, Generation	application	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	IEC 61850, IEC 61970, IEC 61968, IEEE C37.239, IEEE C37 series, MultiSpeak v1-v4, SNMP v3, IEC 61968 Part 9
		networking	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	DNP3, IETF RFC 791 (IPv4), IETF RFC 2460 (IPv6), IETF RFC 6272
		physical	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	IEEE 802 series: IEEE 802.11, 802.15.4, 802.16, IPOS DVB S2, CDMA 2000 series, TIA HRPD and MPS series, 1X-EV-DO, EDGE, UMTS, HSPA+, LTE, ETSI GMR-1 3G

Improved Fault Location

Application	Domain	Layers	Requirements	Standards
Distribution Automation				
Improved Fault Location	Distribution, Operations	application	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	IEC 61850, IEC 61970, IEC 61968, IEEE C37.239, IEEE C37 series, MultiSpeak v1-v4 , SNMP v3, IEC 61968 Part 9
		networking	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	DNP3, IETF RFC 791 (IPv4), IETF RFC 2460 (IPv6), IETF RFC 6272
		physical	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	IEEE 802 series: IEEE 802.11, 802.15.4, 802.16, IPOS DVB S2, CDMA 2000 series, TIA HRPD and MPS series, 1X-EV-DO, EDGE, UMTS, HSPA+, LTE, ETSI GMR-1 3G

Dynamic System Protection

Application	Domain	Layers	Requirements	Standards
Distribution Automation				
Dynamic System Protection for Two-way Power Flows and Distributed Resources	Distribution, Customer, Transmission, Generation, Customer	application	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	IEC 61850, IEC 61970, IEC 61968, IEEE C37.239, IEEE C37 series, MultiSpeak v1-v4, IEEE 1547, SNMP v3, IEC 61968 Part 9
		networking	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	DNP3, IETF RFC 791 (IPv4), IETF RFC 2460 (IPv6), IETF RFC 6272
		physical	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	IEEE 802 series: IEEE 802.11, 802.15.4, 802.16, IPOS DVB S2, CDMA 2000 series, TIA HRPD and MPS series, 1X-EV-DO, EDGE, UMTS, HSPA+, LTE, ETSI GMR-1 3G

Dynamic Volt/Var Management

Application	Domain	Layers	Requirements	Standards
Distribution Automation				
Dynamic Volt/Var Management	Distribution, Customer, Generation, Transmission	application	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	IEC 61850, IEC 61970, IEC 61968, IEEE C37.239, IEEE C37 series, MultiSpeak v1-v4, SNMP v3, IEC 61968 Part 9
		networking	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	DNP3, IETF RFC 791 (IPv4), IETF RFC 2460 (IETF RFC 2460 (IPv6)), IETF RFC 6272
		physical	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	IEEE 802 series: IEEE 802.11, 802.15.4, 802.16, IPOS DVB S2, CDMA 2000 series, TIA HRPD and MPS series, 1X-EV-DO, EDGE, UMTS, HSPA+, LTE, ETSI GMR-1 3G

Conservation Voltage Optimization

Application	Domain	Layers	Requirements	Standards
Distribution Automation				
Conservation Voltage Optimization	Generation, transmission, distribution, customer	application	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	IEC 61850, IEC 61970, IEC 61968, IEEE C37.239, IEEE C37 series, MultiSpeak v1-v4 , SNMP v3, IEC 61968 Part 9
		networking	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	DNP3, IETF RFC 791 (IPv4), IETF RFC 2460 (IPv6), IETF RFC 6272
		physical	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	IEEE 802 series: IEEE 802.11, 802.15.4, 802.16, IPOS DVB S2, CDMA 2000 series, TIA HRPD and MPS series, 1X-EV-DO, EDGE, UMTS, HSPA+, LTE, ETSI GMR-1 3G

Enhanced System Modeling and Planning

Application	Domain	Layers	Requirements	Standards
Asset/System Optimization				
Enhanced System Modeling and Planning	Distribution, Customer	application	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	IEC 61850, IEC 61970, IEC 61968, IEEE C37.239, IEEE C37 series, MultiSpeak v1-v4 , SNMP v3, IEC 61968 Part 9
		networking	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	DNP3, IETF RFC 791 (IPv4), IETF RFC 2460(IPv6), IETF RFC 6272
		physical	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	IEEE 802 series: IEEE 802.11, 802.15.4, 802.16, IPOS DVB S2, CDMA 2000 series, TIA HRPD and MPS series, 1X-EV-DO, EDGE, UMTS, HSPA+, LTE, ETSI GMR-1 3G

Asset Size Optimization

Application	Domain	Layers	Requirements	Standards
Asset/System Optimization				
Asset Sizing Optimization	Distribution, Operations, Customer	application	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	IEC 61850, IEC 61970, IEC 61968, IEEE C37.239, IEEE C37 series, MultiSpeak v1-v4 , SNMP v3, IEC 61968 Part 9
		networking	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	DNP3, IETF RFC 791 (IPv4), IETF RFC 2460(IPv6), IETF RFC 6272
		physical	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	IEEE 802 series: IEEE 802.11, 802.15.4, 802.16, IPOS DVB S2, CDMA 2000 series, TIA HRPD and MPS series, 1X-EV-DO, EDGE, UMTS, HSPA+, LTE, ETSI GMR-1 3G

Asset Condition Monitoring

Application	Domain	Layers	Requirements	Standards
Asset/System Optimization				
Asset Condition Monitoring	Distribution, Operations	application	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	IEC 61850, IEC 61970, IEC 61968, IEEE C37.239, IEEE C37 series, MultiSpeak v1-v4 , SNMP v3, IEC 61968 Part 9
		networking	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	DNP3, IETF RFC 791 (IPv4), IETF RFC 2460(IPv6), IETF RFC 6272
		physical	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	IEEE 802 series: IEEE 802.11, 802.15.4, 802.16, IPOS DVB S2, CDMA 2000 series, TIA HRPD and MPS series, 1X-EV-DO, EDGE, UMTS, HSPA+, LTE, ETSI GMR-1 3G

Customer DR Interconnection

Application	Domain	Layers	Requirements	Standards
Distributed Resources				
Customer Distributed Resource Interconnection	Customer, Distribution, Operations	application	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	IEEE 1547.8, IEC 61850-7-420, IEC 61968, IEC 61850, SEP 2, ASHRAE 135/189, ANSI C12.19/22, EIA 721, EIA 709, OASIS Open ADR, Open ADE, SEP 2.0, SNMP v3, IEC 61968 Part 9
		networking	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	DNP3, IETF RFC 791 (IPv4), IETF RFC 2460(IPv6), IETF RFC 6272
		physical	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	IEEE 802 series: IEEE 802.11, 802.15.4, 802.16, IPOS DVB S2, CDMA 2000 series, TIA HRPD and MPS series, 1X-EV-DO, EDGE, UMTS, HSPA+, LTE, ETSI GMR-1 3G

Coordinated Management of DR

Application	Domain	Layers	Requirements	Standards
Distributed Resources				
Coordinated Management of Distributed Resources	Customer, Distribution, Operations	application	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	IEEE 1547.8, IEC 61850-7-420, IEC 61968, IEC 61850, SEP 2, ASHRAE 135/189, ANSI C12.19/22, EIA 721, EIA 709, OASIS Open ADR, Open ADE, SEP 2.0, IEC 61400-25, SNMP v3, IEC 61968 Part 9
		networking	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	DNP3, IETF RFC 791 (IPv4), IETF RFC 2460 (IPv6), IETF RFC 6272
		physical	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	IEEE 802 series: IEEE 802.11, 802.15.4, 802.16, IPOS DVB S2, CDMA 2000 series, TIA HRPD and MPS series, 1X-EV-DO, EDGE, UMTS, HSPA+, LTE, ETSI GMR-1 3G

PEVs: Optimization Charging

Application	Domain	Layers	Requirements	Standards
Distributed Resources				
Electric Vehicles: Optimized Charging	Customer, Distribution, Operations	application	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net, SAE J2836/1	IEC 61850-7-420, IEC 61968, IEC 61970, IEEE 1547, SEP 2, SAE, NEMA, UL, NEC Codes, SAE J1772, SAE J2847/1-3, SNMP v3, IEC 61968 Part 9
		networking	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	DNP3, IETF RFC 791 (IPv4), IETF RFC 2460 (IPv6), SAE J1772, SAE J2847/1-3, IETF RFC 6272
		physical	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	IEEE 802 series: IEEE 802.11, 802.15.4, 802.16, IPOS DVB S2, CDMA 2000 series, TIA HRPD and MPS series, 1X-EV-DO, EDGE, UMTS, HSPA+, LTE, SAE J1772, SAE J2847/1-3, ETSI GMR-1 3G

Dispatch of PEV Storage

Application	Domain	Layers	Requirements	Standards
Distributed Resources				
Dispatch of Electric Vehicle Storage	Customer, Distribution, Operations	application	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net, SAE J2836/1	IEC 61850-7-420, IEC 61968, IEC 61970, IEEE 1547, SEP 2, SAE, NEMA, UL, NEC Codes, SAE J1772, SAE J2847/1-3, SNMP v3, IEC 61968 Part 9
		networking	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	DNP3, IETF RFC 791 (IPv4), IETF RFC 2460 (IPv6), SAE J1772, SAE J2847/1-3, IETF RFC 6272
		physical	IEEE 2030, NISTIR 7628, IEC PAS 62559, SG Net	IEEE 802 series: IEEE 802.11, 802.15.4, 802.16, IPOS DVB S2, CDMA 2000 series, TIA HRPD and MPS series, 1X-EV-DO, EDGE, UMTS, HSPA+, LTE, SAE J1772, SAE J2847/1-3, ETSI GMR-1 3G

Wide Area Phasor Management

Application	Domain	Layers	Requirements	Standards
Transmission				
Wide Area (Phasor) Measurement	Transmission, Markets, Generation	application	IEEE 2030, NISTIR 7628	NAESB OASIS, IEEE C37.118, , IEC 61850, IEC 61970, IEEE Std. C37.238, IEEE 1588, IEC 61968 Part 9
		networking	IEEE 2030, NISTIR 7628	DNP3, IEEE 802.3, IETF RFC 6272
		physical	IEEE 2030, NISTIR 7628	IEEE 802 series