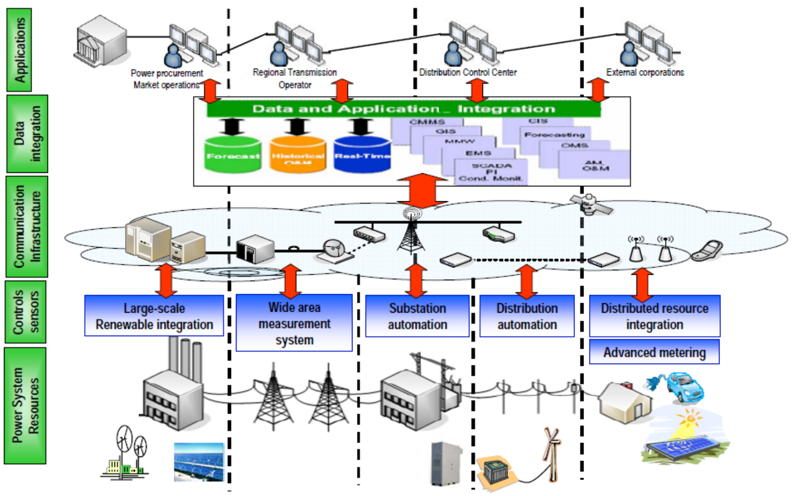
KCP&L SmartGrid
Vision, Architecture, & Road Map

EXECUTIVE SUMMARY

The term "Smart Grid" represents a long-term vision for the electric grid that is highly automated with a tremendous amount of self-operations; distributed generation, and direct customer management of their electrical consumption. The following illustration was developed by EPRI to depict the high level of IT applications and communications integration with the grid that will be required to create the envisioned SmartGrid and create the delivery system of the future.

While the "SmartGrid", in complete vision, cannot be built today, it will continue to evolve and develop over time. However, a "Smarter Grid" can be deployed within the next few years using valuable technologies that currently exist. The "Smarter Grid", will function more efficiently and enabling us to deliver increased levels of reliability, services, and societal benefits economically in an era of rising costs.



The grid that is in place at KCP&L today is substantially "smart" having benefited from decades of power engineering expertise. The systems put in place already execute a variety of sophisticated system operations and protection functions. In addition it should be noted that the foundation for what is now termed the "Smarter Grid" has been under development by the KCP&L and the industry for many years. Much of the integration has been done through incremental applications of technology, custom engineered integrations; work a rounds, and proprietary systems fitting them into system operations as well as possible. Deploying the Smarter Grid will include many incremental enhancements to the existing KCP&L electric power infrastructure.

PROPOSED SMARTGRID ARCHITECTURE

Architecture: *The structure of components, their relationships, and the principles and guidelines governing their design and evolution over time.*

Hence, an architecture is a blueprint for a solution. It is important that the architecture for the ultimate fully functional SmartGrid take a high level perspective to define how the various elements are to be brought together to meet the business, regulatory and technical objectives for KCP&L. The perspectives of the SmartGrid Architecture must encompass all levels of operation from RTO to communications within customer premise and end-use equipment. Based on the architecture, system engineers create designs. Designs are where technology and standards become important.

In developing the proposed SmartGrid Architecture, the KCP&L SmartGrid staff relied heavily on prior industry research work and use-cases developed by EPRI, DOE, California Energy Commission, and other organizations. Current industry Standards work and vendor product development plans were also used as a resource. The SmartGrid Architecture will continue to be a work-in-progress and will evolve as additional applications, requirements, and technologies evolve. Integration of PHEVs into the electric grid is an example of a future application requirement that may not be fully supported by the SmartGrid Architecture, as presented.

So that the proposed SmartGrid Architecture can be more clearly understood, it has been presented in six (6) largely complimentary viewpoints. Each viewpoint represents a different technical perspective and answers a different set of requirements. These viewpoints and their most significant architectural characteristics are:

- **Electrical Grid Monitoring and Control –** these functions will be both hierarchical and distributed with a high degree of automatic unattended distribution substation and field device operation. To further protect against potential disruption of the bulk power system operation, the architecture recommends that the distribution monitoring and control functions be implemented with a DMS and D-SCADA system separate from the existing EMS-SCADA system.
- **Application Systems –** This view presents the logical groupings of applications currently identified as required to implement the ultimate SmartGrid functions. Many of the applications identified do not currently exist at KCP&L or are significant enhancements of the current system. Prior to any implementation, the application functions and requirements must be rigorously defined through a use-case development process.
- **Communications Network –** This view presents the communication architecture to support the SmartGrid. It includes: 1) the expansion of the KCP&L IT IP WAN to all substations to provide the backhaul communications required for the grid automation and AMI; 2) the deployment of an IP SPN (Substation Process Network) to provide the communication requirements for distribution substation automation; 3) the deployment of a private, mesh radio WFAN (Wireless Field Area Network) to provide the field communications required for grid automation and AMI; and 4) a ZigBee communication module in the AMI meters to communicate with WHANs (Wireless Home Area Network) and “smart” appliances.
- **Data Integration & Interoperability –** This view presents the information technologies needed to store and move the data through the communication infrastructure layers from device to device, device to application, and between applications. The National Institute of Standards and Technologies (NIST) has been mandated to drive SmartGrid interoperability Standards to a "consensus" so that they can be implemented by rule by FERC and other oversight bodies.

With the work completed to date by NIST and EPRI, it appears that the following standards will be required key components of this architecture view. 1) IEC-61970 defines a Common Information Model (CIM) and a Generic Interface Definition (GID) for utility systems 2) IEC-61968 defines the SmartGrid back-office application-to-application integration and incorporates a Service Oriented Architecture (SOA) built on top of an Enterprise Integration Bus (EIB); 3) IEC-60870 defines the control center to control center messaging; 4) IEC-61850 will become the communication standard for substation automation and will be expanded to include feeder device automation. DNP 3.0/IP will provide a transition path for field devices.

The AMI and HAN integration standardization remains very polarized and will take longer for a standards path to materialize. Interoperability between systems is a critical issue at this level for applications to leverage the data collected and extract maximum value.

- **Security –** This view presents the security requirements and technologies envisioned to secure the SmartGrid. NERC-CIP compliance is mandated for the bulk power system. The hierarchical nature of the technologies presented in the Communications and Grid Monitoring and Control Architecture views provides for the security "check-points" between control layers that may have different security requirements. Secure connectivity, data encryption, firewall protection, intrusion detection, access logging, change control and the audit reports associated with these applications will likely be required for all SmartGrid communications. To enhance the ability to properly secure the SmartGrid infrastructure it is recommended that: 1) KCP&L utilize private communications (wired and wireless) infrastructure to provide all Grid Operations communications; 2) Public wireless communications may be incorporated to provide additional AMI only back-haul; and a D-SCADA system should be installed to support the DMS and all distribution control functions. Separating the T & D SCADA functions will provide enhanced security for the bulk-power electric grid.
- **Regulatory –** This view presents the regulatory influences and requirements that can become key to any successful SmartGrid deployment. The regulatory aspects of SmartGrid are complicated by the fact that FERC has jurisdictional authority of the transmission/wholesale grid and MO-PSC and the KS-ICC have jurisdictional authority over the operation of the delivery grid in their respective states.

  Both state commissions are currently considering three (3) new PURPA requirements that related directly to the SmartGrid: 1) Rate Redesign to promote energy efficiency; 2) SmartGrid Investment; and 3) SmartGrid Information. KCP&L has recommended that the commissions use a collaborative, workshop process to develop the framework for considering these issues. The IL commission mandated that Ameren and Comm. Edison participate in a formal state-wide SmartGrid Road Map.

  Successful collaboration with the Commissions, Legislatures, and Consumer Organizations on transitional issues will be key to achieving the level of consumer acceptance, participation and enthusiasm in the new energy management concepts needed to make the SmartGrid deployment a success. Inverted Block rate structures will be needed to promote energy efficiency and effective Time of Use rates will be needed to promote shifting energy consumption off-peak. The new standard AMI meters are designed to easily support TOU rates with 4-daily usage times and 4-seasonal periods allowing for very flexible rate implementations.

PROPOSED SMARTGRID ROAD MAP

The "SmartGrid", in complete vision, cannot be built today, but will instead develop over time. Most utilities have a similar vision for an ultimate SmartGrid but will take different paths and time-lines in their respective SmartGrid deployments. These paths will be influenced by regulatory and business drivers and the mix of technologies that a company has currently installed. The SmartGrid Road Map presented here is a plan for implementing the vision and functionality of KCP&L's SmartGrid over time.

Strategic Drivers

- The Sustainable Resource Strategy component of the GPE Strategic Intent.
- Delivery's Strategic Focus on Cost Performance and Customer Satisfaction

Short-Term Business Drivers

- Economy downturn, rate case slippage, and the budget constraints through 2010
- Federal SmartGrid grants through the ARRA Stimulus package.
- Elevate GMO distribution monitoring and control to KCP&L levels to improve reliability and operational costs.
- Implement AMI in GMO to reduce operational costs and provide GMO customers access to same level of information available to KCP&L customers.
- KCP&L AMR contract with CellNet expires Aug. 2014
- Expand of EE and DR programs to GMO customers
- Provide the Net-metering support for solar and other renewable forms of generation to meet the MO Prop-C renewable energy mandate.
- Leverage existing and planned budget dollars to fund SmartGrid deployments where possible.

DEVELOPING THE ROAD MAP

In developing this SmartGrid Roadmap, the SmartGrid staff studied several SmartGrid pilot projects and their respective road map documents. Many of these are focused on AMI and selling SmartGrid as a means of empowering consumers to lower their usage and correspondingly their utility bills. While this may ultimately be the case, with KCP&L's historically low rates, we do not believe our customer are ready to embrace these load shifting initiatives on a large scale. KCP&L's customers continue to be more focused on reliability and quality of service issues.

Our approach

The benefits of the SmartGrid are obvious and the costs to implement it will be considerable. It is important that we 'get it right' and maximize the benefits we obtain as we make the grid smarter and add functions and capabilities. From a regulatory perspective it is also important that the costs associated with the technology rollout be borne by those consumers who receive the benefits. In our analysis, we have concluded that we should not focus immediately on the end-user interactions; rather we should begin on the operational side first. If we focus on the distribution grid operations and AMI, we can streamline operations, thus reducing costs, and gain more control of the grid, thus increasing reliability.

Road Map Principles

- Support the strategic and short-term business drivers.
- There is no SmartGrid silver bullet technology. SmartGrid projects should implement technology that comply with the defined architecture and provide the greatest operational benefits.
- Leverage the Federal Smart Grid demonstration project and investment grant funding authorized by the Energy Independence and Security Act of 2007 (EISA)..
- 10 year time-line to deploy existing and emerging SmartGrid technologies
- By 2020 the SmartGrid infrastructure should be able to support advanced grid technologies and potential customer programs deployed across the grid.
- Initial priority should be on projects that that deploy SmartGrid enabling technologies and leverage existing AMR and DA competencies. AMI is considered an enabling technology. There are immediate utility operation benefits from the AMR functions and the 2-way communications enables additional utility operational benefits.
- Consumer facing programs should be preceded with a consumer education program and a well structured pilot of the technology to evaluate consumer enthusiasm. Numerous consumer facing programs will need to be implemented but, KCP&L should focus on the ones that are of interest to the largest segment of the consumers. There are only so many programs that can be effectively managed.
- The Road Map should be reviewed periodically as business drivers change; revisions made to the Architecture; or new capabilities or opportunities emerge in the industry.

The Road Map

The SmartGrid Road Map presented in the following table is a plan for implementing the vision and functionality of KCP&L's SmartGrid.

	2009		2010		2011		2012		2013		2014		2015		2016		2017		2018	
Stimulus Projects																				
- Grant Development																				
- Extend WAN District Subs		e	d	d	d	d	a	a												
- GMO District DA/DMS		e	d	d	d	d	a	a												
- GMKCPL Dist. DA/DMS/D-SCADA				d	d	d	a	a												
- GMO AMI		e	d	d	d	d	a	a												
- KC Green Zone Pilot		e	d	d	d	a	a	a												
- Battery Pilot			e	d	a	a														
- Extend DA Field Mon & Control							d	d	d	d	d	d	d	d	d	d	d	d	d	d
- Expand AMI Operation Support					e	e	d	d												
					e															
KCPL Metro AMR/DA Upgrade																				
- AMR Contract Expires												♦								
- Extend WAN to Metro Subs					e	e	d	d	d	d	d									
- DA moved to DMS/D-SCADA					e	e	d	d	d	d	d									
- OMS moved to DMS							e	e	d	d	a									
- KCPL AMI Upgrade									e	d	d	d	d	a						
TMS/SCADA incorporate PMU						e	d	d	d	d	a									
Cunsumer Home Automation																				
- Home Automation Pilot							e	e	d	d	a	a								
- Home Automation Programs											e	e	d	d	d	d				
DR & DER Integration																				
- Solar Rebates			d	d	d	d	d	d	d	d	d	d	d	d	d	d	d	d	d	d
- DMS DR & DER Mgt											e	e	d	d	d	d				
Retail Rate Design																				
- flat/inverted rate structure					e	e	d	d												
- TOU rate redesign 4season-4tod									e	e	d	d								
- Day Ahead pricing programs													e	e	d	d				
- RT pricing programs																	e	e	d	d
	2009		2010		2011		2012		2013		2014		2015		2016		2017		2018	

SMARTGRID BACKGROUND

WHY A SMART GRID?

The early roots of current SmartGrid initiatives originate with the Arab Oil Embargo of 1773-74. The formation of the Department of Energy (DOE) was in response to oil embargo. The DOE promoted energy conservation, and thus less reliance on foreign oil, by increasing automobile mpg ratings; increasing energy efficiency of buildings; and increasing appliance efficiencies through the ENERGY STAR® program. As oil supplies stabilized and low gas prices returned there was less public focus on these needs.

The next SmartGrid milestone occurred with the New York City Blackout in 1977. While this incident was initiated by natural causes and was isolated to New York City it focused attention on electrical system and the need for a stable power grid.

The Northeast Blackout of 2003 because the defining incident that launched a multitude of Smart Grid studies and initiatives. The wide spread nature of the blackout and the fact that it was avoidable or could have been significantly minimized with correct operations illustrated the need to significantly invest in the modernization of the electric supply grid.

WHAT IS THE SMART GRID?

As a result of the Northeast Blackout, DOE launched a the Modern Grid Initiative which resulted in a report entitled "A Vision for the Modern Grid"; the European Commission commissioned a similar sturdy which produced the "European SmartGrids Technology Platform"; the Galvin Electric Initiative introduced micro-grids and the concept of "PerfectPower"; and EPRI developed their IntelliGrid Architecture Framework for modernizing the grid by integrating computing technology with the traditional electric grid. These and many other efforts contributed to developing a vision and the requirements of a future modern electric grid.

The grid modernization studies previously noted have lots of commonality but have slightly different emphasis and thus each provided its own answer to "what is a Smart Grid?" Congress solved this definitional problem with the Statement of Policy on Modernization of Electricity Grid" provided the following policy statement which defines the characteristics of a Smart Grid.

> *"It is the policy of the United States to support the modernization of the Nation's electricity transmission and distribution system to maintain a reliable and secure electricity infrastructure that can meet future demand growth and to achieve each of the following, which together characterize 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.*
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."*

The metering industry places great emphasis on AMI and Smart Meters. From many of the trade journal articles one would get the impression that Smart Grid = AMI. Note that of the ten Smart Grid characteristics, AMI and Smart Meters is only a portion of one characteristic. Congress chose to include the entire electric grid in its definition from generation to consumption all components should be smart, efficient, optimized, and reliable

Later in EISA 2007, Section 1306 (d) the term "smart grid functions" is defined to mean any of the following:

1. *The ability to develop, store, send and receive digital information concerning electricity use, costs, prices, time of use, nature of use, storage, or other information relevant to device, grid, or utility operations, to or from or by means of the electric utility system, through one or a combination of devices and technologies.*
2. *The ability to develop, store, send and receive digital information concerning electricity use, costs, prices, time of use, nature of use, storage, or other information relevant to device, grid, or utility operations to or from a computer or other control device.*
3. *The ability to measure or monitor electricity use as a function of time of day, power quality characteristics such as voltage level, current, cycles per second, or source or type of generation and to store, synthesize or report that information by digital means.*
4. *The ability to sense and localize disruptions or changes in power flows on the grid and communicate such information instantaneously and automatically for purposes of enabling automatic protective responses to sustain reliability and security of grid operations.*
5. *The ability to detect, prevent, communicate with regard to, respond to, or recover from system security threats, including cyber-security threats and terrorism, using digital information, media, and devices.*
6. *The ability of any appliance or machine to respond to such signals, measurements, or communications automatically or in a manner programmed by its owner or operator without independent human intervention.*
7. *The ability to use digital information to operate functionalities on the electric utility grid that were previously electro-mechanical or manual.*
8. *The ability to use digital controls to manage and modify electricity demand, enable congestion management, assist in voltage control, provide operating reserves, and provide frequency regulation.*
9. *Such other functions as the (DOE) Secretary may identify as being necessary or useful to the operation of a Smart Grid*

PRIOR WORK LEVERAGED IN DEVELOPING THIS VISION

In developing the proposed SmartGrid Architecture and Road Map, the KCP&L SmartGrid staff relied heavily on prior KCP&L studies, industry research work and use-cases developed by EPRI, DOE, California Energy Commission, and other organizations. Prior works used in developing the SmartGrid Architecture as presented include:

- In 1994, a KCP&L project team issued an internal company report, "Distribution Automation – A Strategic Initiative.
- In 1994, the previous internal report was expanded upon in a masters thesis entitled "Distribution Automation at KCP&L" authored by Duane Anstaett.
- In 2001, EPRI launched the Consortium for an Electric Infrastructure to support a Digital Society (CEIDS) with the objective of conducting RD&D that would lay the foundation for the power delivery infrastructure of the future. CEIDS established a vision of the power delivery system of the future as being a smart grid that incorporates information and communications technologies into every aspect of electric delivery from – from generation to consumption – and created a technology development roadmap.
- In 2003, CEIDS contracted with GE to develop an industry-wide architecture for the communication networks and intelligent devices that would form the basis of the smart grid. The IntelliGrid Architecture was released in 2005 and has now been used by several utilities.
- In 2004, CEIDS contracted with ABB to develop a distributed computing architecture that would be able to effectively convert the tremendous amount of data that would be generated by the smart grid into information that can be acted upon.
- In 2004, CEIDS began defining the requirements for a consumer portal that would serve as the communications link between electric utilities and consumers.
- In 2004, EPRI issued a report "Technical and System Requirements for Advanced Distribution Automation".
- In 2007, the IntelliGrid Architecture Methodology was published by the IEC as a Publically Available Specifications
- In 2006, CEIDS changed its name to IntelliGrid. The IntelliGrid program continues today to conduct research, development and demonstrations that refines the smart grid vision and builds towards an industry architecture that promotes interoperable systems.
- In 2008, The GridWise Architecture Council issued a report entitled "GridWise Interoperability Context-Setting Framework" with the intent to provide the context for identifying and debating interoperability issues and to make drive to consensus on issues to make the integration of complex SmartGrid systems easier.
- In 2007, EPRI issued a report "Value of Distribution Automation Applications" prepared for the California Energy Commission under the Public Interest Energy Research Program.

- In 2008, EPRI issued a report "Integrating New and Emerging Technologies into the California Smart Grid Infrastructure" prepared for the California Energy Commission under the Public Interest Energy Research Program.

Current industry Standards work and vendor product development plans were also used as a resource. The SmartGrid Architecture will continue to be a work-in-progress and will evolve as additional applications, requirements, and technologies evolve. Integration of PHEVs into the electric grid is an example of a future application requirement that may not be fully supported by the SmartGrid Architecture, as presented.

KCP&L'S DISTRIBUTION AUTOMATION HISTORY

KCP&L has a long history of being a progressive industry leader in the area of distribution automation. These long standing efforts are evident in KCP&L's tier-1 standing in reliability performance when KCP&L was named the most reliable electric utility nationwide and awarded the **2007 ReliabilityOne™National Reliability Excellence Award** by the PA Consulting Group.

THE EARLY YEARS

In the early 1980's KCP&L implemented a new centralized EMS/SCADA system to monitor and control the transmission system. Through the 1980's this system was expanded to include the monitor and control distribution substations and the distribution the distribution feeder breaker. By the early 1990's all of the distribution substations in the Kansas City metropolitan service area were monitored and controlled by a centralized distribution dispatch department using the EMS.

DA - A 1993-1999 STRATEGIC INITIATIVE

In 1993, Kansas City Power & Light Company (KCP&L) management established an internal, interdivisional, multi-disciplined team to develop definitions, economic evaluations, recommendation plans for Distribution Automation at KCP&L. The team's purpose was to determine the feasibility of consolidating numerous existing, but independent, automation efforts that were undergoing evaluation throughout the company. Perception was that most of the automation efforts required eventual integration. Consequently, KCP&L management consolidated the DA efforts into one project under the direction of a DA project leader and team

The following subsections contain excerpts from the Distribution Automation Team's report and recommendations to management.

Excerpts from the Distribution Automation Study

Kansas City Power & Light Company has an opportunity to establish a stronger position in the reregulated and competitive arena in which we must conduct business. Coupled with the many changes happening in the electric utility business are even more changes taking place in the telecommunications and information technology markets. Due to deregulation of the telecommunications industry several years ago, many technologies have developed and matured that electric utility companies can economically justify plus provide opportunities to strategically leverage their use to improve customer services, control rising costs, and provide additional services.

All of KCP&L's customers are connected via our electric distribution system. It is reasonable to assume that we will remain in the electric distribution and retail sales for the foreseeable future. Since we serve customers directly through this portion of our system, it appears that' cost effective improvements in distribution operations and customer service is imperative. With the convergence of today's telecommunications and information technologies, it appears that automating the distribution system is a practical endeavor.

Distribution Automation Functional Subsystems

The DA Project Team's first order of business was to identify what functional IT and control subsystems would be considered a part of Distribution Automation. Following is a brief description of each area that was identified as part of distribution automation and therefore considered for inclusion in the DA Project.

- **AMR - Automated Meter Reading.** Provides the ability to replace existing manual meter reading processes with an automated process. Functionality developed as part of AMR significantly impacts the effectiveness of future DSM programs.
- **ACD/VRU – Automatic Call Director with Voice Response Unit.** Primarily provides improved call handling capability for the Call Center and will provide a direct transfer of Outage Calls to the OMS system
- **DFMS-AMFM/GIS – Automated Mapping/Facilities Management/Geographic Information System**. Provides the functionality to support the design, mapping, record keeping and maintenance of the electrical system via a fully connected and geographically related model.
- **DFMS-WMS – Work Management System.** Provides for automated job planning and management of resources.
- **DFMS-EAS – Engineering Analysis System.** Provides the functionality for analysis of the distribution systems electrical performance and plans for the necessary construction and maintenance of the system.
- **DFMS-TRS Trouble Reporting System.** Provides functionality to support the day-to-day trouble call tracking, outage analysis, and service restoration of the electrical distribution system.

- **DFMS-D3MS – Dynamic Distribution Data Management System.** Primarily provides the interface between the DFMS functional component applications and various remote distribution automation RTUs demand side management devices and automated meter reading devices. This subsystem will maintain a data repository of distribution data about the status of remotely monitored points that are dynamic in nature as well as provide the interface between the DFMS application components, the EMS, and the various DA communications networks. During the solicitation of proposals, it was determined that there was no commercially available product available to provide this functionality
- **DFMS-LDA - Line Device Automation**. This includes, but is not limited to automated operation and control of capacitors, switches, reclosers, regulators, and monitoring equipment.
- **DSM - Demand Side Management.** The purpose of DSM is to avoid capital outlays through the influence and control of the customers electric energy use. Energy use is affected by the customers' quantity and timing requirements.

The KCP&L Distribution Automation Vision

The vision for distribution automation consists of using a combination of computer hardware and software, telecommunications networks and electronic devices to provide the following:

1. Monitor and control from a central location, critical electrical devices such as capacitor banks, voltage regulators, switches and reclosers. This automated control and monitoring of such devices will improve outage response and restoration plus achieve efficiencies in the distribution system to minimize losses saving generating capacity and fuel costs.

2. From a central location, send and monitor curtailment requests to commercial and industrial customers' equipment. Both KCPL and the customer can monitor usage to verify compliance.

3. Automatically read meters and have on-line access to demand, time-of-use, and load profile data. Connect/disconnect functions will be performed from a central location as well as provide tamper detection, bill consolidation, and "anytime" reading of meters. Customers may receive their bill any day of the month they choose.

4. Smart homes and customer devices can be connected to be alerted to peak conditions, special pricing or other information from the utility.

5. This technology will interface with KCP&L's current computer network and Customer Information System as well as voice response units. When a customer has a problem, they call KCPL, the Caller ill is forwarded ahead of the telephone call and the system picks up the caller ill. When the system answers the call, the customer is greeted by name and told that we are aware of his/her problem and that a crew has been dispatched and what time they will arrive. When the problem is corrected, the crew can "notify" the system of the correction and the system will call the customer back along with automatically checking to see if the power is actually on by checking the meter.

6. This system can be expanded to read gas and water meters along with providing many other services such as security alarm services as well as many others providing opportunities to expand our revenue stream.

The Business View

We believe that implementation of this technology will enable KCPL to transform the way we do business and interact with customers. This technology will maximize the margins in our core business plus provide opportunities outside the company's traditional markets. Automating key distribution processes, establishing an electronic interface with the customer and creating the opportunity to expand our services places KCPL in a stronger competitive position for the future. As an expanded services provider, KCPL leverages the competencies and assets of an energy services supplier. The telecommunications infrastructure provides a wide variety of business opportunities. Home and business automation is viewed as a logical extension of our energy services.

Improved Customer Service

- Real-time Pricing
- Flexible Billing schedule
- Consolidated Billing
- Offers customers a choice
- Adds services for customers

Improved Revenue

- Pricing incentives to reduce peak load
- Pricing incentives to increase off-peak load
- Increase annual revenues

Const Control through Technology

- Reduce Manpower
- Faster Restoration
- Better Load control
- More efficient utilization of Distribution System

Once this system is in place, KCPL will be strategically positioned for the competitive marketplace and can take advantage of many opportunities. Those opportunities include retail wheeling, improved crisis management on the distribution system, improved responsiveness to customers, and improved energy services.

DA Implementation

In late 1994, realizing the strategic nature of the DA initiative in preparing KCP&L for potential deregulation of the electric markets, the pending Y2K issues, and impact on operational and reliability, the KCP&L management approved the majority of the DA recommendations and authorized to major multi-year projects to implement AMR and DFMS.

Systems Implemented

Between 1995 and 1999 KCP&L implemented the following components of the DA vision.

- AMR. KCP&L implemented the first utility wide 1-way AMR system in the industry automating over 90% of all customer meters.
- ACD/VRU. Provides improved call handling capability for the Call Center and will provide a direct transfer of Outage Calls to the Outage Management System (OMS)
- DFMS-AMFM/GIS. KCP&L entered into data sharing agreements with 7 city and county entities to obtain the most accurate land base information available on which it's hard copy facility maps were digitized.
- DFMS-WMS. Provides for automated job planning and management of resources.
- DFMS-EAS.
- DFMS-TRS. This system is now referred to as the OMS Outage Management System
- DFMS-LDA. Device Automation was limited to Capacitor Automation. Over 600 line capacitors have been automated and routinely maintain the urban circuits at nearly unity power factor.

Systems Not Implemented

Based on further detailed analysis, several of the components of the 1993 DA Vision were not implemented for a variety of reasons.

- DFMS-D3MS – During our vendor selection process the vendor products in this area were found to be lacking the desired functionality. Due to the risk associated with the lack of functionality KCP&L decided to hold off implementing this system and related line device automation. 15 years later, vendors are now providing the desired functionality in solutions referred to as DMS or Distribution Management Systems.
- DFMS-LDA - Line Device Automation. Due to the lack of a D3MS, the automation of switches, reclosers, regulators and other monitoring equipment was deferred.
- DSM - Demand Side Management. During a more detailed review, it was concluded that the communication and control technology to pursue DSM on a large scale lacked sufficient maturity. The greatest potential was found to be in the area of large commercial and industrial customers, not small commercial or residential. Further consideration of DSM was deferred to later consideration as independent business cases and rate tariffs would have to be filed for these.

LEVERAGING THE DA INVESTMENT – 2000-2006 AND FURTHER INTEGRATING THE SUBSYSTEMS

Having successfully implemented the systems initiated by the DA Initiative, KCP&L identified, cost justified, and implemented a series of projects that leveraged the system implementations establishing greater process integration, operational savings and improved operational performance for customers. Many of these projects included first of its kind technology deployments within the utility industry.

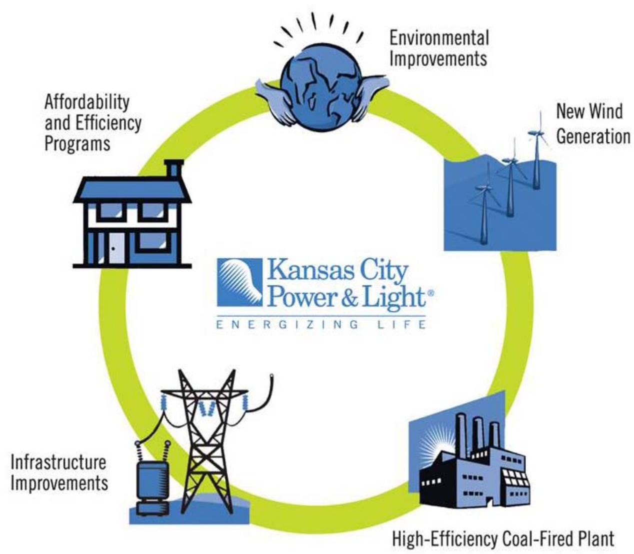
- AMFM/GIS Upgrade. KCP&L became the first utility to port our vendors AMFM/GIS system from their production legacy CAD-RDBMS platform to a fully RDBMS platform.
- AMFM/GIS to WMS Integration. - Integration automated the population of GIS attributes based on the WMS compatible units. This functionality established the foundation for an eventual integrated graphic design function.
- WMS Expanded to Maintenance Work. - Use of the WMS was expanded from design-construction jobs to high volume maintenance and construction service orders, automating and streamlining those processes.
- Account Link WEB portal integrated AMR and CIS – The AccountLink customer web portal was established and daily AMR read information was made available to customers
- AMR integrated with OMS. AMR outage (last gasp) alerts and AMR meter ‘pings’ were implemented to improve outage and trouble response.
- ORS dashboard integrated with OMS. - Implemented the Outage Records System, an OMS data mining and management dashboard provides real time summary and overview of outage statistics. This system provides the real-time “Outage Watch” map on the KCP&L web page, www.kcpl.com.
- MWFM Integrated with AMFM/GIS, OMS, and CIS - Implemented the Mobile Work Force Management system which automated the field processing of Trouble, Outage, and CIS Meter Service Orders.

THE COMPREHENSIVE ENERGY PLAN – 2004-2009

In 2004, GPE and KCP&L undertook a comprehensive strategic planning process. The result was a unique and innovative partnership, in full collaboration with its stakeholders that became the GPE/KCP&L Strategic Intent – a substantive, achievable plan that serves as the company's roadmap in guiding growth and demonstrating leadership in supplying and delivering electricity and energy solutions to meet customers' needs now and far into the future. The company's approach has received national attention. In January 2007, an article in *Barron's* praised GPE's efforts stating: "[T]he kind of strategy it has pursued will be necessary for any utility to succeed in the coming years."

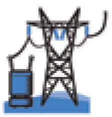
A keystone element of the Strategic Intent is KCP&L's five-year Comprehensive Energy Plan (CEP), designed to supply the region with reliable, affordable energy from cleaner sources, now and for future generations. The five components of the CEP include:

- A new, high-efficiency 850 MW coal-fired power plant using state-of-the-art technology to produce low-cost, long-term energy with fewer emissions;
- Environmental upgrades, made proactively ahead of mandates, to reduce emissions at existing power plants;
- A new wind energy facility providing 100 MW of clean, emission-free power;
- Customer focused efficiency, affordability and demand response programs to recognize energy efficiency as a powerful supply option; and
- T&D infrastructure improvements to strengthen the overall reliability of the company's system and network.



One of the first and most important steps in the CEP development was reaching agreement about the regulatory treatment for the plan. Working with regulators and other stakeholders, the parties crafted an approach where the CEP clearly delineated the methods for which the costs of implementing the five-year plan would be recovered. Through one of the most collaborative processes ever developed, all parties were successful in shaping a community, political and regulatory environment that allowed the company to accomplish its objectives. This approach in developing the CEP was widely hailed throughout the community and in 2005 the CEP received unanimous approval – along with assurances for funding – from Missouri and Kansas regulators.

T&D Infrastructure Improvement Programs



KCP&L currently operates one of the most reliable networks in the country, meaning that the risk of outages for our customers is much lower than for customers in other cities. We want to keep it that way. One element of the CEP involved infrastructure improvements to strengthen the overall reliability of our system and network. Our plan included constructing, replacing and/or upgrading existing transmission and distribution facilities to accommodate new generation, and incorporate new technologies for faster diagnosis and repair of service interruptions.

Asset Management at KCP&L is the structured and disciplined process to develop the program of work for system expansion, system improvements, and maintenance; both corrective and preventive. Our objective is to provide a program of work to achieve the following three key corporate strategic goals for the least overall cost:

Distribution System Inventory Verification Program 2007-2009

This program involves conducting a full overhead distribution system field inventory to verify and augment existing distribution asset information at the component level. Based on the inventory data, the Asset Management and Engineering group will conduct targeted asset management and reliability studies focused on reducing outage minutes caused by: problem or failure prone equipment; wildlife; lightning; overhead wire issues; and, inadequate line design and construction. Benefits resulting from the studies and resulting system improvements include improved reliability and customer satisfaction due to reduced outages.

KCP&L conducted a pilot inventory program in 2005 and, based on the pilot, changes were made to increase the emphasis on network connectivity, customer location verification, and improved transactional processing of field collected updates. The field portion of the program for KCP&L was completed on an 18 month schedule. This included the collection of GPS coordinates for all facility locations, verifying all assets and grid connectivity from substation to customer and verification of customer service locations.

Distribution Automation Programs

In 2006, KCP&L began implementation of the DA programs that were funded under CEP. The objective of the Distribution Automation projects is to improve customer service, reliability, and worker safety by taking advantage of technological innovation. KCP&L has successfully been utilizing automation in Transmission & Distribution applications and has received recognition and awards for its innovative automation technology implementation.

Network Automation 2007-2008

The Network Automation Project involves monitoring of KCP&L's underground (UG) network. Prior to this project, KCP&L had no means to monitor the activity of this network. During annual inspections network protectors were found that had excessive operations and some were in a state of disrepair and had to be replaced. Automation of the network alerts engineers, dispatchers, and the underground workers to abnormal situations that can potentially cascade into larger problems if left unchecked. The project has resulted in a better understanding of the root causes of problems and then proactively managing the network, premature failures have already been averted and it is anticipated that the lives of transformers and network protectors will be extended, all resulting in deferral of replacement of such expensive equipment.

50 C.O. Automation 2008-2009

The 50 C.O. Automation Project involves remote enabling or disabling of over-current relays (50 C.O.) installed at substations. 50 C.O. relays are designed to trip open before lateral fuses blow, thereby preventing sustained outages. The ability to turn the relays off under fair weather conditions will result in a forty to fifty percent reduction in momentary outages–greatly improving reliability and customer quality-of-service. When turned on during storms, this system will allow reclosing to save fuses and reduce outages.

Dynamic Voltage Control (DVC) 2007-2008

As a result of successful testing of the DVC system on the Integrated Circuit of the Future, KCP&L accelerated implementation of the DVC system to all 203 metro Kansas City substation buses, resulting in an estimated 60MW of peak demand reduction.

34-kV Switching Device Automation and Fault Indication 2006-2009

The 34-kV Switching Device Automation and Fault Indication Project involves installation of automated switching devices and fault indicators. The rural circuits in the East and South Districts on KCP&L's 34-kV system are quite lengthy and, therefore, when there is an outage, locating the cause of the outage can be time-consuming, resulting in longer duration outages. Also, because the 34-kV feeders serve various 12-kV substations and municipalities, the number of customers affected is significant. In addition, the automated switching devices will allow faster power restoration to customers because linemen will not be required to drive to a switch and manually operate it. The combination of these technologies will result in shorter outages and improved reliability and customer service.

"Integrated Circuit of the Future"

The "Integrated Circuit of the Future" project involves the integration of various pieces of distribution system automation technologies, engineering applications, and software in order to support KCP&L's vision of implementing a smarter distribution grid. The implementation of a smarter distribution grid will require an incremental approach to fully develop and deploy, and will require extensive collaboration among many industry parties.

Currently the "Integrated Circuit of the Future" is considered a pilot level effort to provide continued proof-of-concept as selected new technologies are integrated into chosen distribution circuits. During this pilot, our goal is to validate the expected benefits of implementing these technologies, and then execute a full-scale system deployment plan.

Rural Power Quality

Insert Rural Power Quality

Customer Programs

As part of its CEP, KCP&L identified fifteen (15) potential energy efficiency/ affordability programs to help customers save money on their energy bills and conserve energy for the future. The impact and effectiveness of these programs will be evaluated in 2009 and determinations made to extend, modify, or terminate individual programs based on their cost effectiveness.

Affordability Programs

Low-Income Affordable New Homes Program

The Low-Income Affordable New Homes Program will be a partnership between KCP&L and non-profit organizations, including Habitat for Humanity and local government community development organizations, to achieve energy-efficient affordable new housing for the low-income community. Incentives will be available for high efficiency CAC, heat pumps and ENERGY STAR® rated refrigerators and lighting fixtures.

Low Income Weatherization and High Efficiency Program

Qualifying lower income customers can get help managing their energy use and bills through KCP&L's low income weatherization and high efficiency program. The program will work directly with local CAP agencies that already provide weatherization services to low income customers through the DOE and other state agencies. KCP&L will provide supplemental funds to the CAPs to cover the cost of weatherization measures. This program will be administered by the CAP agencies and follows the protocol under current federal and state guidelines.

Efficiency Programs

Online Energy Information and Analysis Program Using NEXUS® Residential

The online energy information and analysis program allows all residential customers with computers to access their billing information and comparisons of their usage on a daily, weekly, monthly or annual basis. This tool will analyze what end uses make up what percent of their usage and provide information on ways to save energy by end use. A home comparison also displays a comparison of the customer's home versus an average similar home via an Energy guide label concept.

Home Performance with Energy Star® Program - Training

Home Performance with ENERGY STAR® is a unique program which enhances the traditional existing home energy audit service. This program uses the ENERGY STAR® brand to help encourage and facilitate whole-house energy improvements to existing housing. The program strives to provide homeowners with consumer education, value and a whole-house approach. Contractors are trained to provide "one-stop" problem solving that identifies multiple improvements that, as a package, will increase the home's energy efficiency. While the program goal is saving energy, it also encourages the development of a skilled and available contractor/provider infrastructure that has an economic self-interest in providing and promoting comprehensive, building science-based, retrofit services.

Change a Light – Save the World

Lighting that has earned the ENERGY STAR® rating prevents greenhouse gas emissions by meeting strict energy efficiency guidelines set by the US Environmental Protection Agency and US Department of Energy. ENERGY STAR® encourages every American to change out the 5 fixtures they use most at home (or the light bulbs in them) to ENERGY STAR® qualified lighting, to save themselves more than $60 every year in energy costs.

Cool Homes Program

The Cool Homes Program will encourage residential customers to purchase and install energy-efficient central air conditioning and heat pumps by providing financial incentives to offset a portion of the equipment's higher initial cost. Incentives will be set at approximately 50% of incremental cost. SEER 13.0 and higher efficiency equipment will be rebated in 2005. Since federal standards are set to be increased from 10 SEER to 13 SEER in 2006, KCP&L will modify the 2006 incentives to only rebate SEER levels at 15.0 and above.

Energy Star® Homes – New Construction

This program will require that new homes be constructed to a standard at least 30 percent more energy efficient than the 1993 national Model Energy Code. These savings are based on heating, cooling, and hot water energy use and are typically achieved through a combination of building envelope upgrades, high performance windows, controlled air infiltration, upgraded heating and air, conditioning systems, tight duct systems, and upgraded water-heating equipment. The ENERGY STAR® Homes program will offer technical services and financial incentives to builders while marketing the homes' benefits to buyers.

Online Energy Information and Analysis Program Using Nexus® Commercial

The online energy information and analysis program allows all business and nonprofit customers with computers to access their billing information and compare their usage on a daily, weekly, monthly or annual basis, analyze what end uses make up what percent of their usage, and access ways to save energy by end use through a searchable resource center. This tool also allows the user to analyze why their bill may have changed from one month to another. A business comparison also displays usage benchmarking data versus similar types of businesses.

C&I Energy Audit

KCP&L will offer rebates to customers to cover 50% of the cost of an energy audit. In order to receive the rebate, the customer must implement at least one of the audit recommendations that qualify for a KCP&L C&I custom rebate. Energy audits must be performed by certified commercial energy auditors.

C&I Custom Rebate - Retrofit

The C&I Custom Rebate Retrofit program will provide rebates to C&I customers that install, replace or retrofit qualifying electric savings measures including HVAC systems, motors, lighting, pumps, etc. All custom rebates will be individually determined and analyzed to ensure that they pass the Societal Benefit/Cost Test.

C&I Custom Rebate – New Construction

The C&I Custom Rebate New Construction will provide rebates to C&I customers that install qualifying electric savings measures including HVAC systems, motors, lighting, pumps, etc. All custom rebates will be individually determined and analyzed to ensure that they pass the Societal Benefit/Cost Test.

Building Operator Certification Program

The Building Operator Certification (BOC) Program is a market transformation effort to train facility operators in efficient building operations and management (O&M), establish recognition of and value for certified operators, support the adoption of resource-efficient O&M as the standard in building operations, and create a self-sustaining entity for administering and marketing the training. Building operators that attend the training course will be expected to pay the cost of the course, less a $100 rebate that will be issued upon successful completion of all course requirements. The program is expected to attract customers with large facilities (over 250,000 sq. ft.) that employ full time building operators.

Market Research

The market research component of this program will concentrate on specific opportunities to expand program offerings. Of particular interest will be expanding rebates to other ENERGY STAR® rated appliances such as washing machines; investigating the potential for a 2nd refrigerator pickup program and offering incentives to small commercial customers for ENERGY STAR® rated office equipment.

Demand Response Programs

Energy Optimizer

The Energy Optimizer is an air conditioning cycling program by which KCP&L can reduce residential and small commercial air conditioning load during peak summer days. The company achieves this load reduction by sending a paging signal to a control device attached to the customer's air conditioner. The control device then turns the air conditioner off and on over a period of time depending on the control and load reduction strategy establish by the company.

The Alliance, An Energy Partnership Program

The Alliance, an energy partnership program, is a curtailment and distributed generation program designed to be a partnership with commercial and industrial customers. It is comprised of three coordinated programs. These are MPower, Distributed Generation and Commercial Lighting Curtailment. The program provides incentives to customers to reduce their load or add customer generation to the grid to offset the higher costs KCPL would incur without the reduced load or added customer generation.

A LARGER KCP&L OPERATION

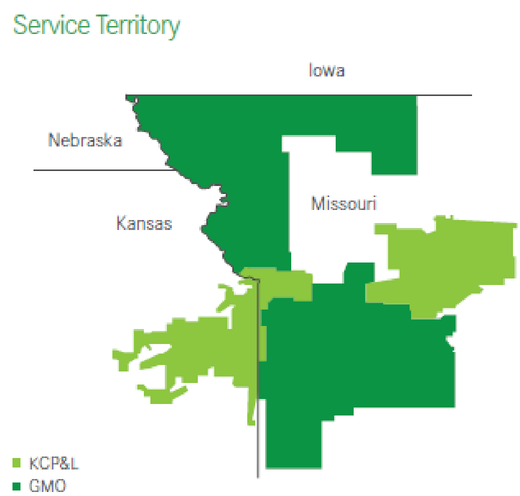
On July 31, 2008, after a 17 month approval process, the Missouri Public Service Commission approved the acquisition of Acquila by Great Plains energy, creating a larger, more electrically diverse utility serving the Kansas City metro and surrounding areas in eastern Kansas and western Missouri.

GPE PURCHASE OF AQUILA

On February 6, 2007, Greate Plains Energy (GPE) entered into agreements with Aquila and Black Hills for two separate but related transactions to purchase the Aquila, an integrated electric and natural gas utility headquartered in Kansas City, Missouri. Aquila had regulated electric utility operations in Missouri and Colorado; regulated gas utility operations in Colorado, Iowa, Kansas and Nebraska; and merchant energy services largely comprising a contractual entitlement to the energy produced by the 340-megawatt Crossroads gas-fired generating facility in Mississippi.

As part of the transactions, which closed July 14, 2008 GPE acquired the Aquila Missouri electric utility operations operated as divisions of Aquila under the names Missouri Public Service and St. Joseph Light & Power and Black Hills acquired the Colorado electric operations and all gas operations. The Missouri electric operations were subsequently renamed KCP&L-Greater Missouri Operations (GMO).

As illustrated in the figure, the GMO service territory is contiguous to KCP&L's service territory in Missouri. Significant synergies were identified and achieved by consolidateing the operations of both utilities into the existing KCP&L organization.



COMBINING THE KCP&L & GMO OPERATIONS

On the day the GMO acquisition was completed (July 14, 2008), KCP&L rebranded all utility locations with a new logo that represents today's KCP&L - a strong regional utility. Since Day One, employees have worked tirelessly to provide customers with seamless service as a single, operationally integrated organization. Our integration efforts focused on bringing together more than 820,000 customers across 47 counties; coordinating the operations of nearly 3,200 employees, 30 percent of which came from GMO; and ensuring reliable service across our expanded network.

Table 1 provides some statistics of the KCP&L and GMO combined operations and integration highlights include:

- Consolidating the two GMO unions into our three existing unions under common work rules.
- Combining two separate company platforms for accounting, HR systems, and telecom and network infrastructure into a single platform for each function.
- Managing the integration process to deliver immediate and sustainable synergy benefits.

We're also already seeing the impact of extending our operational and reliability best practices to the GMO operations. The results from the fourth quarter JD Power Residential Customer Satisfaction survey showed continued improvement in the GMO territory, and the combined utilities placed in Tier 1 for the calendar year of 2008.

Table1: Statistics of the KCPL and GMO Operations

	KCP&L	Aquilla now GMO	Combined
Customers	505,000	315,000	820,000
- Residential	88%	88%	88%
- Commercial	11%	11%	11%
- Industrial/Wholesale	1%	1%	1%
Employees	2,500	1,250	3,260
Service Area – sq.mi.	4,700	13,300	18,000.
- Counties Served	24	33	47
Retail Sales - MWh	15,587,000	3,502,000(5mo)	19,089,000
Generation Capacity- MW	4,053	1,998	6,051
- Coal	56%	39%	50%
- Gas	20%	35%	25%
- Nuclear	14%	- - -	9%
- Oil	10%	3%	8%
- Gas/Oil	- - -	17%	6%
- Coal/Gas	- - -	6%	2%
- Wind (100Mw)	>1%	- - -	>1%
Transmission	1,700 mi.	1,600	3,300 mi.
Substations			320
Distribution - Overhead	9,000 mi.	8,000	17,000 mi.
Distribution - Underground	3,900 mi.	3,100	7,000 mi.

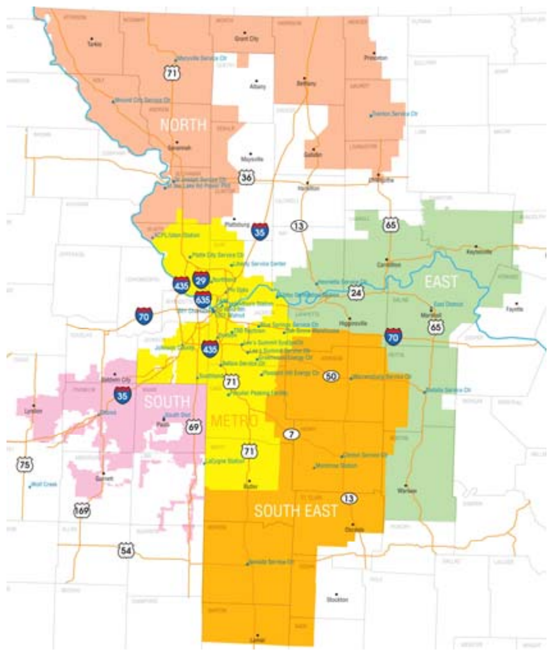
COMBINING KCP&L & GMO DISTRIBUTION OPERATIONS

For operations purposes, KCP&L has divided the KCP&L and GMO service territories into five (5) Districts; the Metro District and four outlying (North, East, Southeast, and South). These geographic operating divisions are illustrated in Figure **1.**

This figure illustrates and the corresponding statistics highlight the significant differences in the electrical grid serving the Metro District to and grid serving the four outlying Districts.

Figure 1: KCPL Metro and District Operations

	Metro	Districts
Customers	650,000	170,000
Counties	5	42
Area - sq.mi.	2,600	15,400
Cust. Density	250/sq.mi.	11/sq.mi.
Transmission	161kv	161/69/35kv
Distribution	12 &13kv	35,25,13,12,4,2kv
Substations	120	165
Circuits	942	468
Cust/Sub.	5,400/sub.	1,030/sub.
Cust/Ckt.	690	363
Ckt. Area	3.75 sq. mi.	33 sq.mi.



Within the Metro District, KCP&L and GMO have very similar electrical grid configurations serving high density urban core and moderate density suburban areas. Distribution substations are typically served from 161kv transmission and nearly all of the distribution feeders are monitored and controlled by their respective SCADA systems.

The Districts, in general, can be characterized as classic 'rural America'. Within the Districts there are 10-12 communities of 10,000 plus populations, many smaller communities, and vast sparsely populated rural areas.

The electrical grid in the Districts is as different from the metro grid as are the differences in population densities.

- Metro subs supplied from 161kv trans.; District subs supplied by 69kv and 35kv sub-trans.
- Metro has high sub-circuit ratio; Districts have low sub-circuit ratio.
- Metro circuits are capacity constrained; District circuits are voltage constrained.
- Metro circuits have high degree monitoring (GMO ckts monitored to a lesser degree) District circuits have little monitoring/control
- Metro has common dist.voltage 12 & 13; Districts have numerous non-uniform voltages.

COMBINING KCP&L & GMO OPERATIONS SYSTEMS

At the time of the merger, the Delivery organization included Customer Services, Distribution Operations, Energy Solutions, Information Technology and Transmission Services, all areas that directly touch customers. That's why it was so important to a single division that the transition goes smoothly.

KCP&L goal for the transition was 'seamless' Day 1 customer service. Customers will receive one bill format and will call a single number to report service interruptions or make billing inquiries. One location will provide quick-response service, relaying needs to appropriate service territories. Employees may have multiple computer screens, but customers won't know that.

While operating redundant computer systems for the two operations was a short term, stop-gap method to provide transparent service, it would not achieve the level of desired synergies expected for the merged company. To obtain the synergies and increased performance of staff and the grid, system consolidation needed to occur as rapidly as possible. The following are some of the key Operations Systems that needed to be integrated to support the Day 1 vision.

- **Customer Information System (CIS).** Aquila and KCP&L each used different versions of the same CIS platform. Because each system is in need of upgrade in the next few years, the decision was made to forgo consolidation until the time of upgrade. Aquila bill formats were modified to be consistent with KCP&L formats and the KCP&L WEB portal is used to access both systems.
- **Work Management System (WMS).** Both Aquila and KCP&L used the Logica STORMS work management system. On Day 1 these two systems were consolidated into the KCP&L STORMS astatine.
- **Geographic Information System (GIS).** Both Aquila and KCP&L each had GIS systems containing electronic representations of transmission and distribution facilities. After careful review, the Aquila GIS data was exported and merged into the KCP&L GIS.
- **Outage Management System (OMS).** Both Aquila and KCP&L each had OMS systems for processing light-out and trouble call. The Aquila OMS was home-grown and after review it was determined that the KCP&L OMS would be used for both operations. These systems are planned to be consolidated approximately Day 1+365 after the GIS data combination is complete.
- **EMS/SCADA (EMS).** Both Aquila and KCP&L each had EMS/SCADA systems monitoring and control of the transmission network and substation devices. KCP&L was in the process of implementing the latest version of the ABB EMS/SCADA system. The GMO EMS/SCADA functions will be migrated to the KCP&L EMS/SCADA system.

COMBINING KCP&L & GMO DISTRIBUTION AUTOMATION

Table2: Automation Summary by Operations Area

	KCP&L Metro KC	GMO Metro KC	KCP&L Districts	GMO Districts
SCADA - Trans > 100kv	ALL	ALL	ALL	ALL
SCADA - Trans > 60kv	ALL	ALL	ALL	ALL
SCADA - SubTrans	ALL	Partial	Partial	Partial
SCADA - Dist Pwr. Transf.	ALL	Partial	Partial	Partial
SCADA -				
Capacitor Automation	ALL	None	Partial	None
AMR/AMI	ALL (1-way)	None	None	None

DISTRIBUTION GRID AUTOMATION APPLICATIONS AND TECHNOLOGIES

This section characterizes the broad range of distribution grid automation applications and technologies and develops a comprehensive list of Distribution Grid Automation applications to consider when developing the SmartGrid architecture and road map.

BACKGROUND AND DEFINITION OF DISTRIBUTION GRID AUTOMATION FUNCTIONS

Advanced information technology, databases, communication and controls are increasingly making a vast array of new distribution grid automation applications possible. To the extent they are economic and/or promote other policy goals, KCP&L has the ability to build these technologies into its distribution system. While many of the grid automation applications apply to a broad range of systems, it is important to recognize that there are a number of different types of distribution systems that have different characteristics. Applications that provide positive value in some part of the system may not be applicable or have positive economics in other parts of the system. The major categories of system types are the following;

- **Urban networks.** These systems supply high density loads that may be a combination of commercial facilities, residential, and light industrial loads. They will typically be underground systems and may already be network configurations.
- **Suburban systems.** These systems are characterized by moderate load density and a variety of load types. They may be a combination of overhead and underground systems with a general trend towards increasing the penetration of underground distribution. They are typically radial primary systems that may have open tie points between feeders.
- **Rural systems.** These systems will typically be overhead, radial circuits that are less likely to have open tie points to other feeder circuits. They may be very long primary distribution systems (e.g. 20 miles and more).
- **Special systems.** Special systems may supply premium power parks, office parks, or other special groups of loads. Special designs (e.g. microgrids) and technologies (e.g. custom power technologies) may be justified for these systems based on the needs of the end users supplied. There may be special contracts associated with the customers on these systems.

Automated Grid: Delivering Energy and Information

Traditional distribution systems were designed to perform one function, to distribute electrical energy to end-users. Increasingly, distribution systems are delivering electrical energy and information between participants, system operators, and system components. As demand response and other Distributed Energy Resources (DER) penetration of the grid increases, the lines between electricity supplier and consumer blur because many of participants will assume both roles. Similarly, the exchange of information is multi-directional and will facilitate system operation and potentially enable decisions on whether to “supply” or “use” electrical energy based on dynamic rather than static prices.

To exchange electricity and information, the automated grid will contain two interrelated components:

1. A communication architecture to facilitate the system monitoring and control functions of the automated system. Ideally, this will be migrating to open systems that will allow integration of technologies and components from multiple vendors.

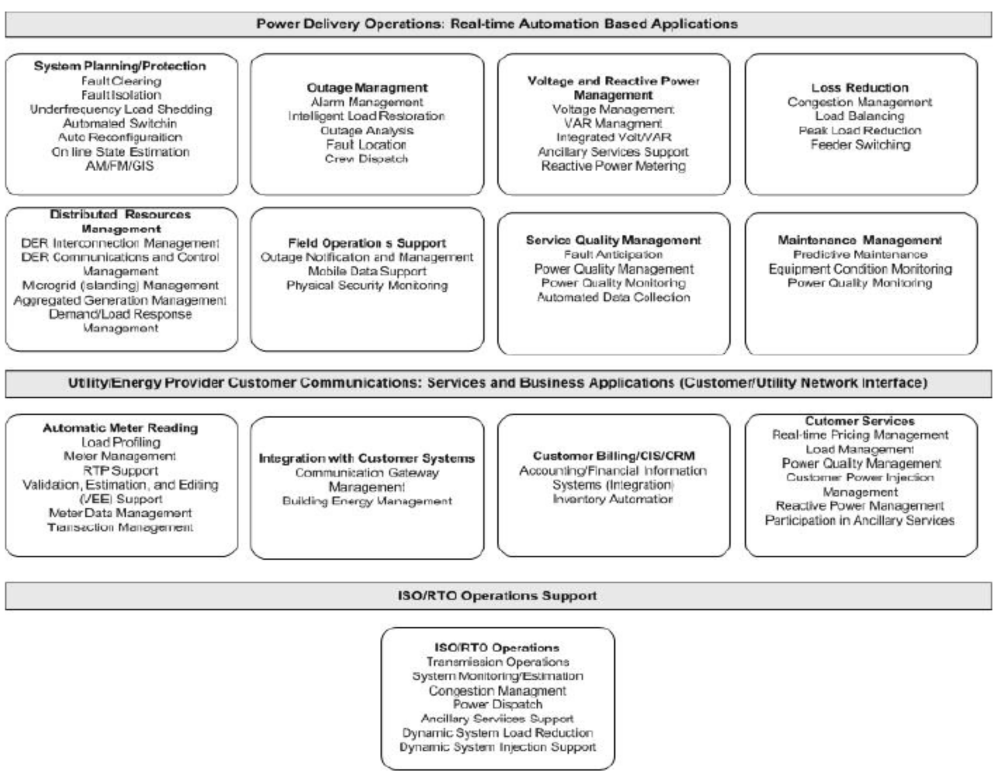
2. New electrical architectures and protection systems that enable an interoperable network of components.

These two components are synergistic and inter-related with each other, and together they comprise the automated distribution system. The communication and information protocols required by the automated grid comprise a good number of the applications identified in this section.

Distribution Grid Automation Functions

Many individual functions that can be included in the overall category of distribution grid automation are facilitated by the exchange of information. This section describes a few of the important functions briefly to provide a background for the survey and basis for the valuation development. Figure 2 summarizes automation functions that were identified as part of the Intelligrid Architecture project.

Figure 2: Automation Summary by Operations Area



Distribution Grid Automation Technology Categories

A number of different technologies that fall within Distribution Grid Automation are available or are being developed to achieve these functions. The major categories for each technology are briefly described.

Substation SCADA

Substation SCADA systems are usually considered part of substation automation rather than distribution automation. Monitoring and control of breakers and equipment in distribution substations is widespread. Probably 80% of substations in the US have some level of remote monitoring and control. However, significant opportunities exist to improve the substation applications and to integrate these applications with technologies applied on the actual distribution circuits.

An example of an important new benefit of substation monitoring systems is automated fault location. Detailed monitoring information from substation monitors can be used in conjunction with an understanding of the electrical topology to identify possible fault locations on the distribution system. This type of capability can be used in conjunction with outage management systems (OMS) to significantly improve fault response times and repair times.

Distribution SCADA (monitoring and controlling the switches on the distribution circuits)

This is an area of significant investment in the industry as the concept of substation automation migrates to the distribution circuits. Substantial benefits in terms of reliability improvements can result from having remote control of switches on the distribution circuits, especially if the switches can operate automatically to reconfigure circuits and limit the extent of outages.

Automated Volt/Var Control Systems and Power Quality Management

These systems involve monitoring and control of capacitor banks and/or voltage regulators on distribution circuits to provide improved voltage control and to minimize losses on distribution circuits. It is often possible to justify investment in these systems based on the loss reduction benefits alone. In the future, integration with more extensive monitoring, two-way communications, and application of power electronics technologies for better reactive power control will all provide opportunities for improved volt/var control systems.

Future extensions of volt/var control systems will look at a broader range of power quality characteristics on the distribution system. These characteristics could include harmonic distortion, unbalance, and voltage fluctuations (flicker, sag performance, and stray voltage conditions).

Outage Management Systems (OMS)

Outage management systems are software systems that integrate geographical information systems, electrical topology, and customer information systems to predict portions of distribution circuits that are interrupted (usually based on customer calls) and manage the response to these interruptions. They can include coordination of work crews and management of all reliability data for reliability reporting. Outage management systems are not technically part of distribution automation, but it is critical that automated systems for distribution be coordinated closely with outage management systems.

Advanced Metering Systems (AMI)

Advanced Metering Infrastructures (AMI) are the next generation of metering systems to facilitate a wide range of technologies for both the customer and the overall power system operation. Most utilities have some type of automated meter reading (AMR) systems, at least for portions of their customer base. However, AMI involves a much higher level of automation and two way communication to enable advanced applications, like automated demand response, load control systems, customer information systems, and information systems to support distribution automation. This last function can become an integral part of distribution information systems to support automation in the future

Advanced Monitoring Systems and Intelligent Applications

Many utilities have power quality monitoring systems, monitoring systems for distribution SCADA, and other types of monitoring equipment. The application of intelligent electronic devices (IEDs) such as intelligent relays, reclosers, capacitor controllers, smart switches, etc. is becoming increasingly widespread. The availability of this vast amount of monitoring information creates opportunities for new intelligent applications that can be integrated with automation systems. Applications include automated fault location and equipment diagnostics.

Distribution System Real Time State Estimation and Control

Future distribution control systems will incorporate systems that can process data from monitoring throughout the distribution system to continuously assess the state of the system, identify opportunities for improved efficiency, and implement configurations to minimize the risk of outages. These systems will integrate advanced metering systems with more traditional monitoring systems and real time models of the distribution system. While this type of technology is used throughout transmission systems, it is not yet applied for distribution.

Integration of Distributed Resources

Automated distribution systems will permit more effective integration of distributed resources and higher levels of penetration on distribution systems than is current feasible. These integrated systems will take advantage of the real time system control and two way communication capabilities to improve system reliability and provide new options for improved efficiency and system operation.

Asset Management Applications

Automated distribution systems will have the capability to track the performance of distribution assets (cables, transformers, breakers, reclosers, sectionalizers, capacitors, regulators, arresters, etc) in a much more detailed manner than they are now tracked. Loading information, operation history, and disturbance characteristics can all provide information about the condition of assets. This condition information can be used to make more intelligent decisions about maintenance programs and asset replacement strategies.

New Distribution System Technologies

New technologies are becoming available that will shape the distribution system of the future. These technologies will become integral parts of automated distribution systems. It is important to consider the technologies when planning future systems and ways to integrate these technologies with existing systems.

Electrical and Electronic Technologies

- Distributed energy resources (distributed generation and storage).
- New sensor technologies that will allow collection of electrical and performance information from devices and components throughout the system.
- Monitoring and analysis technologies for identifying system and equipment problems before actual failures (e.g. distribution fault anticipator, capacitor problem identification, regulator problem identification, etc.)
- Power quality enhancement technologies for the distribution system (e.g. DVR, Statcom)
- Solid state breakers and switches for fast fault clearing, system reconfiguration, and transientfree switching (e.g. capacitors).
- Load management technologies (end user systems that must be coordinated with ADA)
- Power quality enhancement technologies for end user facilities that should be coordinated with ADA.
- Advanced metering capabilities that will allow intelligent applications to be coordinated with detailed characteristics of end user systems.
- Advanced electrical system configurations, such as intentional islanding (including microgrids), dc ring buses, looped secondary systems, and advanced distribution networks.

Communications Characteristics and Technologies

The link between customers, smart devices on the grid, and system operators lies in the communication infrastructure. As the complexity of these communications grows and the time-frame decreases, the demands on the communications infrastructure to provide faster exchange of data (high bandwidth) increases. Also, as more critical functions are automated, heightened security of information becomes more and more important. Finally, to promote inter-operability of many different devices manufactured by many different vendors, common protocols and open architecture will be desired.

Communication technology projects include:

- Open, standardized communication architecture
- Advanced, secure communication media (including wireless, PLC, satellite, etc.)
- Open information exchange model for work process management
- Consumer Portal and Advanced Metering systems

- Sensing and monitoring devices implementing features of new communications architecture and with integrated intelligent applications that become an integral part of overall system control schemes
- Real time state estimation and predictive systems (including fault simulation modeling) to continuously assess the overall state of the distribution system and predict future conditions, providing the basis for system optimization
- Advanced control systems to optimize performance of the entire distribution system for efficiency, asset management, reliability, quality, and security
- Load management and real time pricing systems that integrate with end user and DER systems to optimize overall system performance and efficiency
- Asset management and work management systems that integrate with intelligent monitoring systems, customer information systems, and forecasting tools to optimize investments and maintenance based on the specific requirements of individual systems

Distribution Grid Automation Categories

The SmartGrid team has identified a comprehensive list of specific distribution grid automation applications and technologies that have potential for inclusion in the KCP&L SmartGrid portfolio at some point on the RoadMap continuum. The distinction between applications and technologies is subtle, but is often important. A technology by itself does not provide any specific value; rather, it is how that technology is used to make changes to the way the grid operates that provides value. Therefore, for assessment of the value of grid automation we focus on applications, recognizing that there may be one or more technologies that enable that application to be implemented.

Each of the applications and technologies has been categorized as DA (Distribution Automation), (ADA) Advancing Distribution Automation, or (SNM) SmartGrid Network Management. The distinction of these Distribution Grid Automation classifications may not be a fine like but can be generally divided based on the characteristics summarized in Table 3.

Table 3: Differences between DA, ADA and SNM classifications

Distribution Automation	Advanced Distribution Automation	SmartGrid Network Management
Focused on automated and remote operation of basic distribution circuit switching functions.	Focused on complete automation of all the controllable equipment and functions on the distribution system to improve operation of the system. ADA takes DA to a higher level with enhanced monitoring, analysis, and control.	Focused on the economic integration of consumer and utility distributed and renewable energy resources into distribution networks.
Device integration primarily to Distribution SCADA system	Distribution SCADA system integrated to DMS and other distribution analytical applications.	DMS/SCADA integration with AMI, MDM, and other customer/market analytical systems to initiate DER/DR pricing signals.
Communications primarily use client-server serial protocols.	Device operability requires client server, device communications.	Device interoperability requires peer-to-peer, 2-way device communications.

Distribution Grid Autmation Applications

Applications related to distribution grid automation are listed by application area in Table 4. Within each area, the applications have been sorted in approximate stage of development, with the first application.

Table 4: Summary of Distribution Grid Automation Applications

Application Area	Application	DA	ADA	SNM
SCADA applications	Monitoring and control of substation breakers (Substation SCADA)	X		
	Monitoring of substation Transformer (Substation SCADA)	X		
	Monitoring and control of substation Regulator/LTC (Substation SCADA)	X		
	Monitoring and control of substation capacitor (Substation SCADA)	X		
	Monitoring and control of remote breakers and reclosers on the distribution (Feeder SCADA)	X		
	Monitoring and control of remote capacitor banks for volt/var control	X		
	Monitoring and control of remote voltage regulators for volt control.	X		
Advanced monitoring applications	Integration of data from monitors and sensors throughout the system intocommon database platforms		X	
	Faulted segment identification		X	
	Advanced Fault Location (location along segment)		X	
	Incipient fault detection (and location)		X	
	Identification of other system problems – harmonic resonance, voltagevariations, unbalance, repetitive faults, galloping conductors, etc.		X	
	Monitoring of Network Transformers and vault conditions		X	
	Monitoring UG Cable ambient duct temperature		X	
	Integration of ambient duct temperature with real-time cable rating analysis		X	
	Equipment diagnostics (identifying equipment problems before they causefailures – capacitors, regulators, switchgear)		X	
	Asset management applications (using monitoring to support condition-based maintenance applications.		X	
	Detecting losses, including non-technical losses through processing of monitoring data (real time data from throughout the system – advanced metering)		X	
Automatic system reconfiguration	Automated switching for isolating faulted segments			
	Automated switching for restoring loads after fault condition is cleared, etc.			
	Automated switching for dynamic reconfiguration (e.g., improved efficiency, reduced losses, prevent overloading, lower probability of outage, etc.)			

Table 4: Summary of Distribution Grid Automation Applications (Cont.)

Application Area	Application	DA	ADA	SNM
Advanced Outage Management Systems (OMS)	OMS integration with AMI for determination of faulted segments			
	OMS integrated with AMI for confirmation of power restoration after restoration.			
	OMS integrated with fault indicators to enhance faulted segment determination			
	OMS integration with automatic circuit reconfiguration systems			
	OMS integrated with feeder monitoring and advanced monitoring fault location applications			
Coordinated voltage and var control	Remote switching of capacitors to optimize var and voltage conditions (including sensor requirements)			
	Coordinated control of voltage regulators and substation tap changers			
	Coordination with advanced technologies like static var compensators, statcoms			
	Coordination with var compensation available from loads and distributed generation (effect of significant solar penetration)			
	Coordination with var control from intelligent universal transformer (IUT)			
Distribution voltage reduction	DVR controlled with EMS/SCADA for system wide demand reduction during constrained hours.			
	DVR coordinated with control of capacitor banks and regulators to prevent undervoltage			
	DVR controlled at substation with feeder/substation monitoring to prevent distribution system overload.			
	DVR coordinated with AMI to obtain information on under voltage and demand reduction at customer.			
Conservation voltage reduction	CVR managed from substation but controlled based on sensors around system.			
	CVR coordinated with control of capacitor banks and regulators throughout system.			
	CVR coordinated with voltage control at individual customer facilities (e.g.MicroPlanet).			
	CVR coordinated with AMI to obtain information on under voltage and consumption reduction at customer.			
Real time state estimation	(This is an application that supports various applications above – dynamic reconfiguration, reliability management, asset management, conservation voltage reduction, load control, etc.)			
	Real time management of the power system configuration information and electrical model.			
	Real time power flow simulation of distribution system based on sensors around the distribution system.			
	Real time state estimation integrated with advanced metering (information from virtually all customers as basis for real time state estimation).			

Table 4: Summary of Distribution Grid Automation Applications (Cont.)

Application Area	Application	DA	ADA	SNM
Demand Response	Direct Load Control coordinated with EMS to reduce peak demand/energy consumption			
	Direct load control coordinated with DMS to prevent distribution substation/circuit overload			
	Direct load control coordinated with Substation control system to prevent distribution substation/circuit overload			
	Direct load control to coordinate with circuit reconfiguration			
	Load control through dynamic pricing to coordinate with circuit loading conditions (improve reliability, prevent equipment overloading, delay investment requirements for system reinforcements)			
	Monitoring and verification of response (AMI)			
Distributed Energy Resource Management	Control distributed generation (DG) resources and energy storage (ES) to meet system level capacity requirements.			
	Control distributed generation resources and energy storage to meet substation/feeder capacity requirements.			
	Control distributed generation resources and energy storage for distribution voltage support.			
	Coordination of DG, ES, and DR for improved voltage control reduced losses, or improved reliability.			
	Coordination of DG, ES, and DR for micro-grid operation in an islanded configuration.			
Optimized power quality management	Harmonic control coordinated with volt/var control systems (integration of filters as needed)			
	Integration of advanced technologies for var and harmonic control (active filters).			
	Localized power quality improvement with DVR, UPS, etc.			
	Power quality and reliability management with distributed generation and storage (including microgrids as appropriate)			
Advanced Asset Management Systems	Advanced equipment diagnostics based on monitoring to characterize the condition of equipment on the distribution system			
	Advanced methods to determine remaining lifetime of equipment based on manyfactors (machine learning techniques)			
	Advanced testing techniques (on line and off line) to support asset condition assessments: Cables, transformers, breakers, capacitors, regulators, arresters, Advanced technologies (solid state equipment, etc.)			
	Using high frequency signals, such as BPL, to identify equipment problems and condition.			
	Incorporation of equipment condition information into decision making tools for system configuration and management.			

Distribution Grid Automation Technologies

The applications listed in the previous section are each supported by a number of different technologies. Because many technologies also support a variety of different applications, mapping the correspondence of technologies to applications it enables would be somewhat speculative. Instead, technologies are listed by general category in Table 5 below.

Table 5: Summary of Distribution Grid automation Technologies

Technology Area	Specific Technologies	DA	ADA	SNM
Communications (Communications is a foundation for virtually all the applications and consists of high speed two-way communications throughout the distribution system and to individual customers).	Radio technologies			
	Wimax			
	Peer-to-peer systems (e.g., zigbee for local systems like substation)			
	BPLC (Broadband over Powerline Communications)			
	Fiber optic applications on the distribution system			
	Network connectivity			
	Technologies to use public communication infrastructures for automation and metering applications with required security and reliability.			
Sensors (the next basic requirement for virtually all the applications)	Integration of sensors in the substation for monitoring applications.			
	Advanced sensors for the distribution system • Fault indicators • Optical sensors (voltage and current) • Other low cost sensor options • Widely distributed low cost sensors • Sensors with integrated communications (wireless)			
	Using advanced metering as the sensors for distribution applications.			
Monitoring devices and technologies	Monitoring technologies integrated with distribution equipment (relays, regulators, capacitor controls, reclosers, etc).			
	Special purpose monitoring technologies			
	Special monitoring applications (special processing for decision making, e.g., DFA) • High frequency signal characteristics • Wavelet processing • Harmonic processing • Detecting arcing conditions • Fault location • Detecting incipient faults			

Table 5: Summary of Distribution Grid automation Technologies (Cont.)

Technology Area	Specific Technologies	DA	ADA	SNM
Monitoring data integration	IEC 61850 models for all distribution substation equipment			
	Extension of IEC 61850 throughout the distribution system			
	Extension of information models to distributed generation and storage technologies			
	Extension of information models to new technologies (static compensators, IUT, etc.) Integration of data with Common Information Model (CIM) to facilitate use of information in a wide variety of applications from real time state estimation to asset management.			
	Standard database designs for distribution information management			
Conventional switchgear advancements	Controllable vacuum breaker and SF6 breaker for fast switching applications and controlled zero crossing applications			
	Integration of monitoring and communications with breaker for distribution information management			
Solid state switch	Solid state switch for fast fault clearing			
	Solid state switch for reduced transients during capacitor switching			
	Solid state switch for fast system reconfiguration			
	Solid state switch to facilitate microgrids			
Advanced meters	Meters that can provide gateway to load control and load management through pricing information.			
	Meters that can provide interface for direct load control in times of emergency and during system reconfiguration efforts.			
	Meters that integrate with OMS.			
	Meters that can integrate with distribution information systems (e.g. for real time state estimation)			
Advanced protection systems	Advanced reclosers for integration with automatic reconfiguration systems.			
	Adaptive protection systems that can be coordinated with changing system configurations and conditions.			
	Adaptive protection systems that can be controlled based on environmental conditions (e.g. storms).			
	Protection systems that provide integrated monitoring information for overall distribution management systems			
	Advanced expulsion and current limiting fuses for fast clearing of faults with integrated sensors and communications.			

Table 5: Summary of Distribution Grid automation Technologies (Cont.)

Technology Area	Specific Technologies	DA	ADA	SNM
Distribution equipment advanced technologies	Transformers • High efficiency • Integrated sensors and communications for loading, hotspots,condition assessment			
	Capacitors • Integrated sensors and communications • Integrated protection			
	Regulators • Improved switching for fast voltage control • Integration with monitoring and control systems • Intelligent algorithms for coordination with distributed generation			
	Arresters • Integrated monitoring and communications to identify problems • Dynamic arrester characteristics for control of different types of transients and overvoltages			
Conductors	Advancements in underground cable design, installation, and reliability to improve overall system reliability			
	Integration of sensors and communications with underground cables			
	Advanced conductors for improved reliability with animals and trees			
	Advanced conductors with sensors to detect loading, arcing, etc.			
	Superconducting cables			
Advanced power electronic technologies	Static var systems			
	Statcom			
	Integration of var control with local var sources (local generation, local capacitors, local technologies like statcoms that also provide power quality improvement)			
	Active filters (integrated harmonic control)			
	Intelligent universal transformer (including support of dc supply options for facilities)			
	Advanced CVR technology for local voltage sag ride through			
	Advanced UPS for local reliability improvement and possible integration with microgrids			
Power quality improvement technologies	Harmonic filters on the distribution system			
	Static var systems and statcoms for fast voltage control			
	DVR for local voltage sag ride through support			
	Advanced UPS for local reliability improvement (and also can provide var support)			

Table 5: Summary of Distribution Grid automation Technologies (Cont.)

Technology Area	Specific Technologies	DA	ADA	SNM
Distributed generation advancements	Integration of local generation with distribution control • Fuel cells • Microturbines • Diesel and gas generators • Local CHP			
	Plug-in hybrid vehicle as a device for local generation and storage thatcan be integrated with the distribution system			
New energy storage technologies	New technologies for energy storage at the distribution level (e.g. substation, feeder)			
	New technologies for energy storage at the customer level that can be integrated at the distribution level			
Overall system control technologies	Optimizing for energy efficiency and losses with dynamic configuration capability, load control, and flexible var control			
	Optimizing local and system generation for reliability, power quality, and losses.			
	Managing system configuration and monitoring information – real timestate estimation.			
	Distributed agents to improve reliability, information flows, security etc.			
	Optimum system management with microgrid			

SMARTGRID ARCHITECTURE

The grid that is in place at KCP&L today is substantially "smart" having benefited from decades of power engineering expertise. The systems put into place already execute a variety of sophisticated system operations and protection functions. In addition it should be noted that what is now termed "smart grid" has been under development by the KCP&L and the industry for many years. Much of the integration has been done through incremental applications of technology and fitting them into system operations as well as possible. Many of these are custom engineered integrations; work a rounds, and proprietary systems. The smart grid will include many incremental enhancements to the existing KCP&L electric power infrastructure. That said, KCP&L desires to shift gears and fully integrate dispersed systems including visions of integrating dynamic new customer systems applications, improved system automation and control as well as the projected siting of significantly more renewable resources. This compels KCP&L to develop a SmartGrid Architecture since the company needs to move from one-off and custom integration to mass deployment with a high degree of interoperability.

DEVELOPING A SMARTGRID ARCHITECTURE

Since 2001, EPRI has managed a collaborative research, development, and demonstration (RD&D) process that has accelerated the industry's migration towards a SmartGrid. KCP&L has been an active funder and participant in this RD&D effort. KCP&L has leveraging EPRI's extensive work in developing a smart grid vision and roadmaps for other utilities in developing the SmartGrid Architecture Vision for KCP&L outlined in this section.

Architecture Defined

Architecture is defined as:

Architecture: *The structure of components, their relationships, and the principles and guidelines governing their design and evolution over time.*

This definition, adopted by the Department of Defense, is based on an IEEE Standard. There are other definitions but this definition is sufficient for the purpose of developing our SmartGrid Architecture. It is important that the architecture for the ultimate fully functional SmartGrid take a high level perspective to define how the various elements are to be brought together to meet the business, regulatory and technical objectives for KCP&L. The perspectives of a SmartGrid Architecture must encompass all levels of grid operation from ISO/RTO to communications within customer premise and end-use equipment. Based on the architecture, system engineers create designs. Designs are where technology and standards become important.

Multidisciplinary Nature of the Smart Grid

The power grid of today was primarily built upon the disciplines surrounding power engineering with some assistance from other disciplines. The smart grid will require a more complete interdisciplinary approach to adequately describe. The power system and information technology, as well as communication infrastructure and architectural components must be included in the picture. Architecture includes the distributed computing infrastructure that requires systems engineering as well as communications, software engineering, data management, network management, architecture development and other related disciplines that are evolving. Thus, a high level description of a smart grid is the merging of two infrastructures, composed of the electric power infrastructure and a communications infrastructure that enables and intelligent grid.

Technology Categories of the Smart Grid

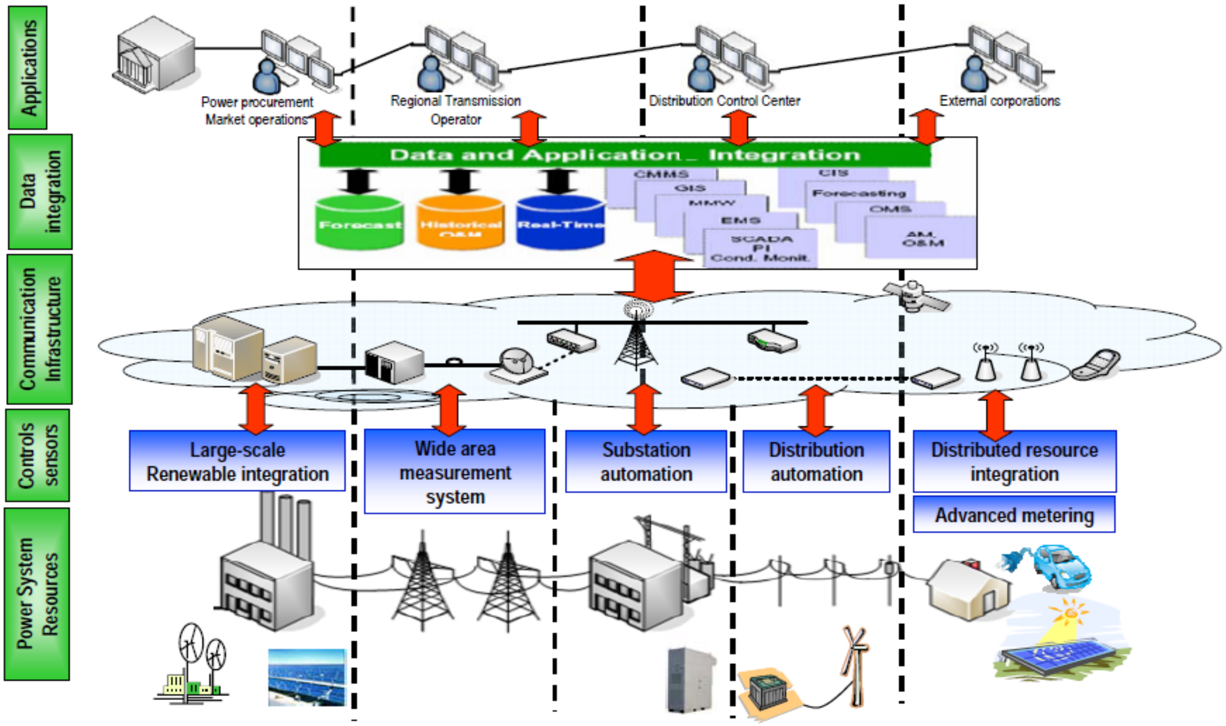
If the grid is going to be smart, it will use a well orchestrated combination of a wide variety of equipment hardware, control algorithms and communications networks. These smart grid components can be related by different technology levels and major business function. Both utility business and technical perspectives together assist an understanding of how the elements come together and what is needed to enable the smart grid. Figure 6 depicts a structured method by which to identify the various technical elements of the smart grid.

The smart grid is comprised of various levels of technology ranging from power delivery infrastructure (that is, physical assets and energy resources), plus sensors and control devices, to communication infrastructure that gathers data from sensors and measurement systems. The information is used to determine the state of the power system and transform its operation, maintenance, and planning using knowledge derivable from a rich set of collected data. This transformation depicts a grid enabled to be operated, planned, and maintained more intelligently through development and deployment of key technologies that enable these characteristics.

As depicted in Figure 6, traditional business areas include generation, transmission, distribution and external operations applicable to enhancing customer service. Different classes of technologies and applications are typically found within each business unit at each hierarchical level. The following hierarchy is used to characterize technologies at different levels, as depicted in Figure 1.

- **Power system resources:** This level designates the traditional physical assets that constitute the power system (cables, transformers, lines, meters) as well as the resources connected to it (wind farms, PV installations, CHP systems, storage, PHEV).
- **Controls and sensors**: This level designates the equipment and materials installed on the power system that allow and facilitate the control or the measurement of the different assets.
- **Communication infrastructure**: This level designates the combination of the systems needed to support the two-way exchange of information with the controls and sensors level. It is constituted of the physical infrastructure and the associated protocols.

Figure 1 – Technical Elements of the SmartGrid



- **Data integration:** This level designates the information technology systems needed to store the data provided through the communication infrastructure layer and allow their use by the relevant applications to transform it into information. Interoperability between systems is a critical issue at this level for applications to leverage the data collected and extract maximum value.
- **Applications:** This level designates the business processes supported by human interfaces providing decision support. Information collected at the data integration level is used by business process supporting applications to improve efficiency, reliability, and cost effectiveness of power system operations, planning, and maintenance.

SMARTGRID ARCHITECTURE VIEWS

So that the proposed SmartGrid Architecture can be more clearly understood, it is being presented in six (6) largely complimentary viewpoints. Each viewpoint represents a different technical perspective and answers a different set of requirements. These viewpoints are:

- Electrical Grid Monitoring and Control
- Application Systems
- Communications Network View
- Data Integration & Interoperability
- Security
- Regulatory

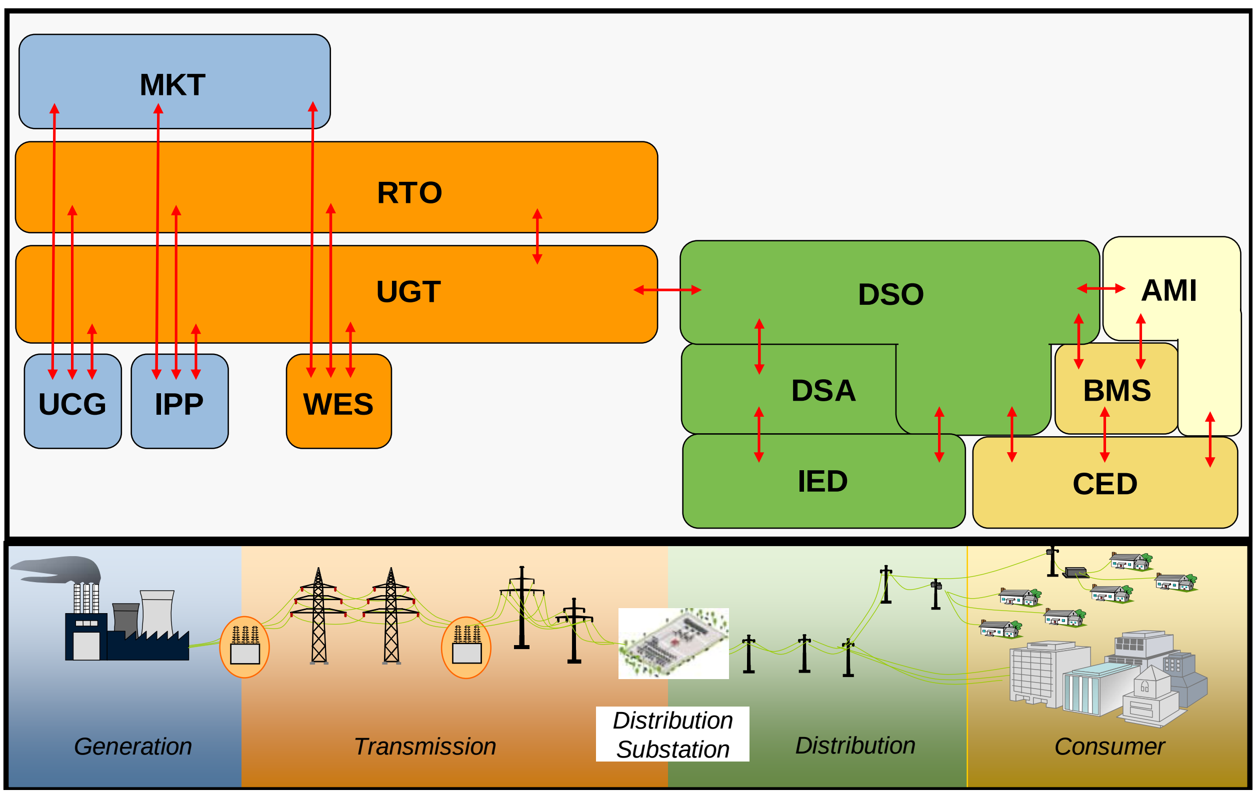
Grid Monitoring and Control View

This view designates the grid monitoring, operation and control process performed unattended and those supported by human interaction. The grid monitoring, operation and control functions of the new smart grid will be both hierarchical and distributed as illustrated in Figure 2**.**

The hierarchical levels are significant because communication between levels is generally controlled to some degree. Applications at a higher level may only see an aggregated view of applications at a lower level. This does not mean that lower level data is hidden from a higher level, only that the specifics of how to communicate and the semantics of lower level applications may be wrapped by a higher level communications mechanism and semantics.

- **Regional Transmission Organization (RTO) –** At this level the Southwestern Power Pool will be responsible for Inter-RTO and inter-utility/IPP exchanges within the SPP. The grid monitoring and control at this level will be automated and centrally operator monitored.
- **Utility Generation & Transmission (UGT)** - At this level KCP&L will be responsible for its internal central generation station dispatch and transmission system operation. The grid monitoring and control at this level will be automated and centrally operator monitored.

Figure 2 – Electrical Grid Monitoring and Control Architectural View



- **Distribution System Operations (DSO)** - At this level KCP&L Distribution Operations will be responsible for the utility wide distribution system operation and control. The grid monitoring and control at this level will be automated and centrally operator monitored.
- **Automated Metering Infrastructure (AMI)** - At this level KCP&L Metering Operations will be responsible for the utility wide meter reading, operation, and connect/disconnects. The AMI monitoring, operation, and control at this level will be automated and centrally operator managed.
- **Distribution Substation Automation (DSA)** - At this level each distribution substation control module will be responsible substation-wide monitoring and control. This includes status of devices within the substation and devices on the circuits' emanating from the substation. The grid monitoring and control at this level will be automated and centrally monitored by the higher DSO control system and operators.
- **Feeder Intelligent End Devices (IED)** – At this level each IED will be responsible for monitoring local conditions and acting upon these local conditions in a pre-programmed manner. IEDs are distribution equipment with microprocessor based control and communication modules. These include RTUs, AMI meters, Distributed Energy Resources (DER), and DA devices. The IED monitoring and control operation will be monitored by the appropriate DSA control module and centrally by the DSO control system and operators.
- **Building Energy Management System (BMS) –** At this level the BMS will be responsible for monitoring local conditions, price and control signals, and consumption information and acting upon these conditions in a pre-programmed manner. The BMS should receive premise consumption information from the local AMI meter and may receive price and control signals from either the AMI meter or through an Internet gateway. The only monitoring of the BMS activity will be via the resulting consumption changes recorded via the AMI meter.
- **Consumer End Device (CED) –** At this level the CED or appliance will be responsible to price and control signals received from the BMS and/or the utility AMI meter and acting upon these signals in a pre-programmed manner. The only monitoring of the CED activity will be via the resulting consumption changes recorded via the AMI meter and feedback from any direct utility controlled device (thermostat, AC control, pool pump, etc.)
- **Wholesale Electric Markets (WEM) –** At this level
- **Utility Central Generation(UCG) –** At this level the
- **Independent Power Producer(IPP) –** At this level the
- **Wholesale Energy Supplier(WES) –** At this level the
-

Application Systems View

This view designates the business processes supported by human interfaces providing decision support. The Information collected at the data integration level is used by business process supporting applications to improve efficiency, reliability, and cost effectiveness of power system operations, planning, and maintenance. The currently identified potential applications needed to support the SmartGrid have been organized into logical groupings so they can be more easily correlated to the other Architecture views. These application groupings are graphically depicted in Figure 3.

Wholesale Electric Markets (WEM)

- Energy Trading and Settlement
- Market Operations

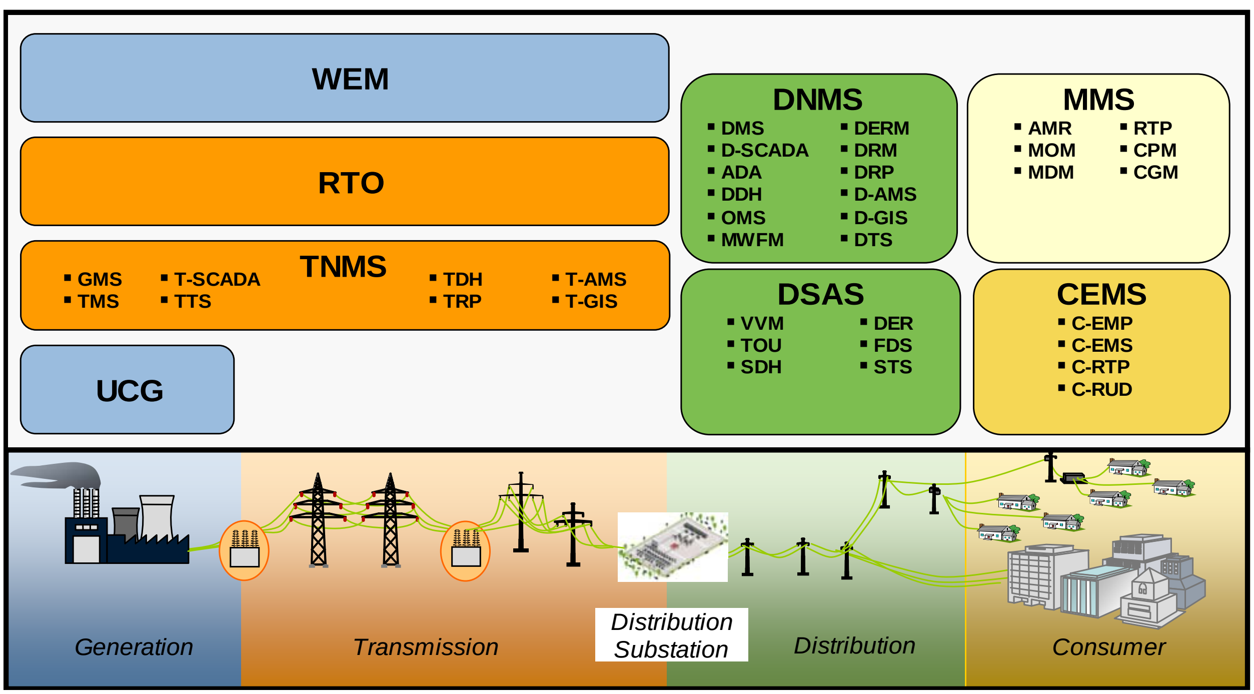
Regional Transmission Organization (RTO)

- Regional Power Scheduling
- Market Monitoring
- Reliability & Congestion Management
- Wide Area Measurement (Phasor Measurement Units)
- Expansion Planning

Utility Central Generation (UCG)

- Generation Monitoring & Control
- Plant Operation Management Systems

Figure 3 – Application Systems Architectural View



Transmission Network Management Systems

- GMS - Generation Management System
- TMS - Transmission Management System
- T-SCADA - Transmission System Control and Data Acquisition
- TDH – Transmission Data Historian
- TRP – Transmission Reporting Portal (dashboard)
- T-AMS – Transmission Asset Management System
- T-GIS – Transmission Geographic Information System
- TTS – Transmission Training Simulator

Distribution Network Management Systems

- DMS - Distribution Management System
- ADA – Advanced Distribution Automation
- DERM – Distributed Energy Resource Management
- DRM – Demand Response Management
- OMS – Outage Management System
- MWFM – Mobile WorkForce Management
- D-SCADA - Distribution System Control and Data Acquisition
- DDH – Distribution Data Historian
- DRP – Distribution Reporting Portal (dashboard)
- D-AMS – Distribution Asset Management System
- D-GIS – Distribution Geographic Information System
- DTS – Distribution Training Simulator

Distribution Substation Automation Systems

- VVM – Integrated Volt/Var Management
- FDS – Fault Detection and & Switching
- STS – Substation Training Simulator
- SDH – Substation Data Historian
- DER - Distributed Energy Resource Management
- TOU –

Measurement Management Systems

- MDM – Meter Data Management
- AMR – Automated Meter Reading
- MOM – Meter Operations Management
- RTP – Real-Time Pricing
- CPM – Consumer Energy Portal Management
- CGM – Consumer Gateway Management

Consumer Energy Management Systems

- C-EMP – Consumer Energy Management Portal (via Internet)
- C-EMS – Consumer Energy Management System
- C-RTP – Consumer Real-Time Pricing Response
- C-RUD – Real-Time Usage Display

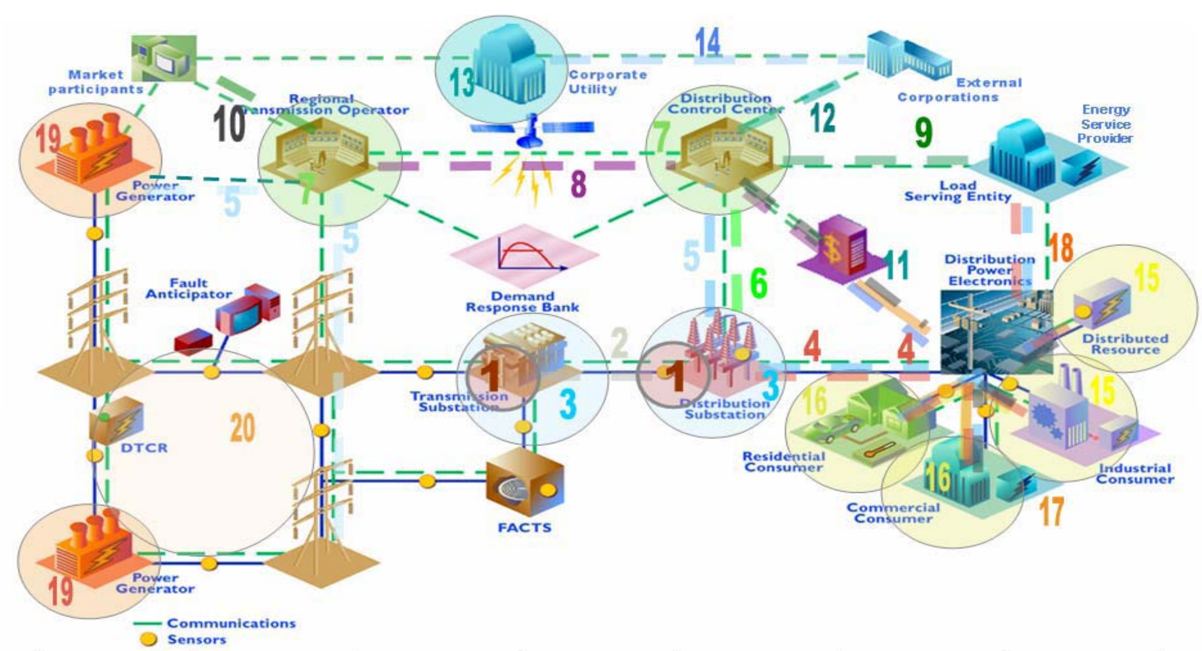
Communications Network View

This view designates the combinations of communication networks needed to support the two-way exchange of information through all levels of architecture.

The EPRI IECSA (IntelliGrid) project identified twenty one (21) distinct computing environments required to support the entire ultimate SmartGrid. These are illustrated in Figure 4 and described in IECSA Volume IV Appendix E. IECSA defines an 'Environment as a logical grouping of power system requirements that could be addressed by a similar set of distributed computing technologies. With a particular environment, the information exchanges used to perform power system operational functions have very similar architectural requirements, including their:

- Configuration requirements
- Quality of Service Requirements
- Security requirements
- Data Managements requirements

Figure 4 – IECSA Environments in Power System Operations

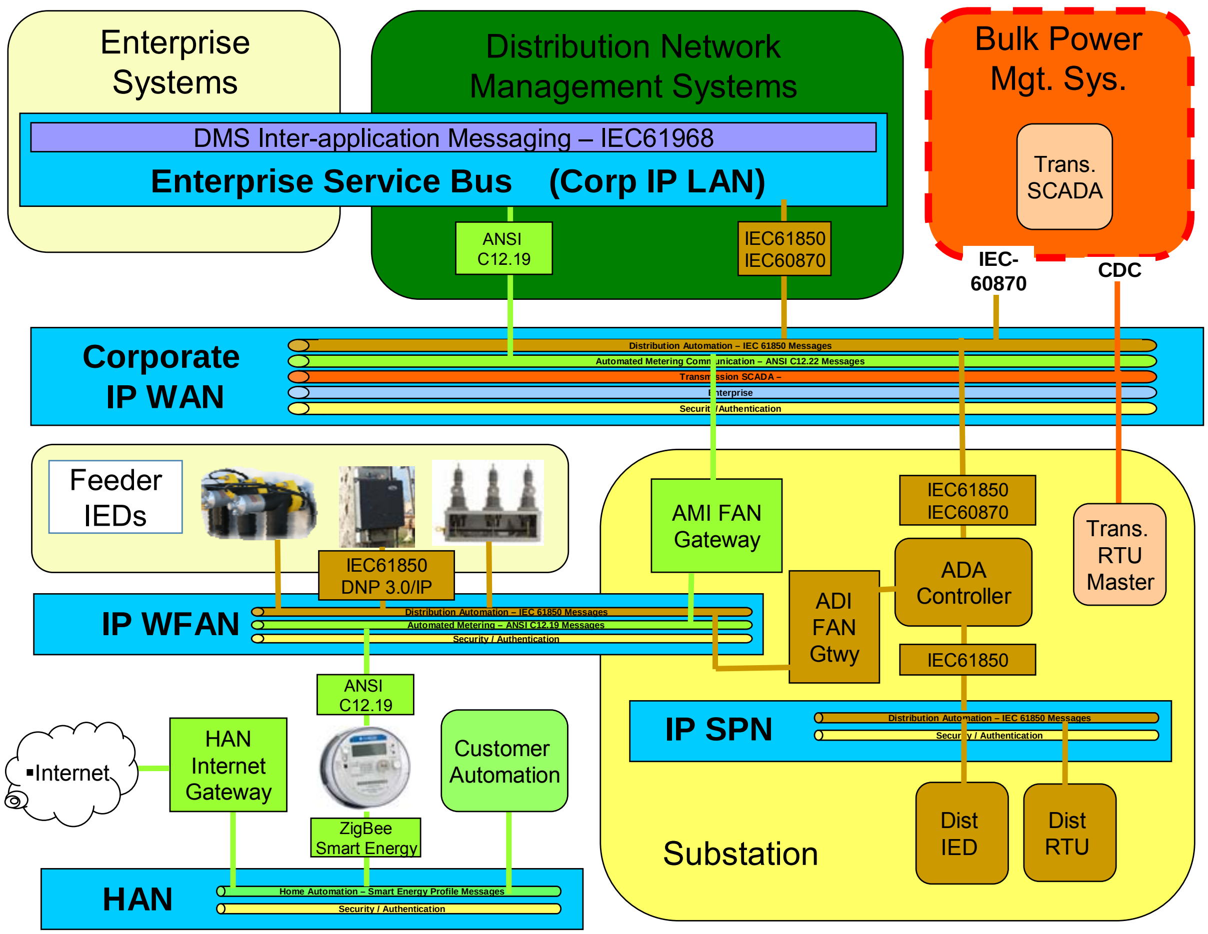


1 Deterministic Rapid Response Intra-Sub station	4 Inter-Field Equipment	7 Intra-Control Center	10 RTOs / Market Participants	13 Intra-Corporation	16 Intra-Customer Site	19 HV Generation Plant
2 Deterministic Rapid Response Inter-Site	5 Critical Operations DAC	8 Inter-Control Center	11 Control Center / Customer Equip	14 Inter-Corporation	17 Inter-Customer Sites	20 Field Equipment Maintenance
3 Critical Operations Intra-Sub station	6 Non-Critical Operations DAC:	9 Control Centers / ESPs	12 Control Center / Corporations	15 DER Monitoring and Control	18 Customer / ESP	21 Special

As can be seen in Figure 4, the management of the power system infrastructure is increasingly reliant on the information infrastructure as automation continues to replace manual operations, and is therefore affected by any problems that the information infrastructure might suffer.

The communications network view for the information networks proposed to support the deployment of the Smarter Grid is depicted in Figure 5 and the characteristics of each network layer are described in the following subsections. As the Smarter Grid evolves into the SmartGrid, communication technologies will evolve and the information network requirements will increase. The communications technologies associated with this network architecture view will also evolve.

Figure 5 – Smarter Grid Communications Network View



The following subsections present the significant network communication characteristics for each of the network layers and describes the EICSA SmartGrid Communication Environment that must be supported by each layer.

Enterprise Network

The KCP&L IT Enterprise Network Layer will provide the back-office communications required for the various SmartGrid systems, CIS, ERP systems, and the EMS/SCADA systems.

Recommended Network Technology

- Quality of Service - 99.9% Availability, Time-Sync Data, High Speed < 1 sec.
- Application Layer - SNTP
- Transport Protocol – TCP
- Network Protocol – IP v4 or v6
- Link and Physical – 1Gb Ethernet

IESCA #7 Intra-Control Center Environment

- Quality of Service - 99.9% Availability, Time-Sync Data.
- Data Exchange - IEC-60870-6 ICCP

IESCA #8 Inter-Control Center Environment

- Quality of Service - 99.9% Availability, Time-Sync Data, Medium Speed < 10 sec
- Data Exchange - IEC-61968 and Enterprise Service Bus (ESB)

Smarter Grid Wide Area Network

The Smarter Grid Wide Area Network (WAN) layer requires the expansion of the KCP&L IT IP WAN to all substations to provide the backhaul communications required for the grid automation and AMI;

Recommended Network Technology

- Quality of Service - 99.9% Availability, Time-Sync Data, High Speed < 1 sec.
- Application Layer - SNTP
- Transport Protocol – TCP
- Network Protocol – IP v4 or v6
- Link and Physical – Private Fiber, Microwave, and/or Leased Lines

IESCA #5 Critical Operations DAC and SCADA Environment

- Quality of Service - 99.9% Availability, Time-Sync Data, High Speed < 1 sec.
- Data Exchange - IEC-61850 (DNP3.0/IP as a transition)
- Data Exchange - IEC-60870-6 ICCP

IESCA #6 Non-Critical Operations DAC Data Acquisition Environment

- Quality of Service - 99.9% Availability, Medium Speed < 10 sec.
- Data Exchange - IEC-61850 (DNP3.0/IP as a transition)
- Data Exchange - IEC-60870-6 ICCP

IESCA #15 DER Monitoring and Control Environment

- Quality of Service - 99.9% Availability, Time-Sync Data, High Speed < 1 sec.
- Data Exchange - IEC-61850 (DNP3.0/IP as a transition)
- Data Exchange - IEC-62350 DER General
- Data Exchange - IEC-61400-25 DER Wind Power

IESCA #18 Customer [Meter] to ESP Environment

- Quality of Service - 99.0% Availability, Time-Sync Data, Medium Speed < 10 sec.
- Data Exchange - ANSI C12.19 Meter Data Tables

IESCA #11 Control Center to Customer Environment

- Quality of Service - 99.0% Availability, Medium Speed < 10 sec.
- Data Exchange - Smart Energy Profile

Substation Process Network

An IP based Substation Process Network (SPN) will be deployed within each distribution substation to provide the communication requirements for substation automation.

Recommended Network Technology

- Quality of Service - 99.999% Availability, High Data Precision, Ultra-High Speed < 4 ms
- Application Layer - SNTP
- Transport Protocol – TCP
- Network Protocol – IP v4 or v6
- Link and Physical – Private 100 Mb Ethernet or 100Kb Wireless FAN

IESCA #3 Critical Operations Intra-Substation Environment

- Quality of Service - 99.999% Availability, High Data Precision, Ultra-High Speed < 4 ms
- Data Exchange - IEC-61850

IESCA #5 Critical Operations DAC and SCADA Environment

- Quality of Service - 99.9% Availability, Time-Sync Data, High Speed < 1 sec.
- Data Exchange - IEC-61850 (DNP3.0/IP as a transition)

IESCA #6 Non-Critical Operations DAC Data Acquisition Environment

- Quality of Service - 99.9% Availability, Medium Speed < 10 sec.
- Data Exchange - IEC-61850 (DNP3.0/IP as a transition)

Field Area Network (FAN)

A wireless Field Area Network (FAN) will be deployed to provide the private, field communications required for grid automation and AMI.

Recommended Network Technology

- Quality of Service - 99.9% Availability, Time-Sync Data, High Speed < 1 sec.
- Application Layer - SNTP

- Transport Protocol – TCP
- Network Protocol – IP v6
- Link and Physical – Private 100Kb Wireless FAN

IESCA #4 Inter-Field Equipment Environment

- Quality of Service - 99.9% Availability, Time-Sync Data, High Speed < 1 sec.
- Data Exchange - IEC-61850 (DNP3.0/IP as a transition)

IESCA #5 Critical Operations DAC and SCADA Environment

- Quality of Service - 99.9% Availability, Time-Sync Data, High Speed < 1 sec.
- Data Exchange - IEC-61850 (DNP3.0/IP as a transition)
- Data Exchange - IEC-60870-6 ICCP

IESCA #6 Non-Critical Operations DAC Data Acquisition Environment

- Quality of Service - 99.9% Availability, Medium Speed < 10 sec.
- Data Exchange - IEC-61850 (DNP3.0/IP as a transition)

IESCA #15 DER Monitoring and Control Environment

- Quality of Service - 99.9% Availability, Time-Sync Data, High Speed < 1 sec.
- Data Exchange - IEC-61850 (DNP3.0/IP as a transition)
- Data Exchange - IEC-62350 DER General
- Data Exchange - IEC-61400-25 DER Wind Power

IESCA #18 Customer [Meter] to ESP Environment

- Quality of Service - 99.0% Availability, Time-Sync Data, Medium Speed < 10 sec.
- Data Exchange - ANSI C12.19 Meter Data Tables

IESCA #11 Control Center to Customer Environment

- Quality of Service - 99.0% Availability, Medium Speed < 10 sec.
- Data Exchange - Smart Energy Profile

Home Area Network – Meter Gateway

A ZigBee communication module in the AMI meters will be used to establish a communication gateway to the HAN (Home Area Network), “smart” appliances, and Home Energy Management Systems. This wireless gateway will provide real-time customer usage data directly from the meter and relay pricing and other communications from the back office applications.

Recommended Network Technology

- Quality of Service - 99.0% Availability, Medium Speed < 10 sec.
- Network and Physical – ZigBee Wireless HAN

IESCA #11 Control Center to Customer Environment

- Quality of Service - 99.0% Availability, Medium Speed < 10 sec.
- Data Exchange - Smart Energy Profile

KCPL #21 ESP Meter to Customer

- Quality of Service - 99.0% Availability Medium Speed < 10 sec.
- Data Exchange - Smart Energy Profile (Consumption Data)

Home Area Network – Broadband Gateway

Some customers may desire to have more direct oversight of their energy consumption but may not want to manage a Home Energy Management System. For these customers, our architecture includes a KCP&L or third-party WEB hosted home automation and energy management systems are being developed and will become commonplace. This broadband gateway will connect to a local gateway appliance, provide a WEB based user interface, and obtain pricing and other communications from the back office applications.

Recommended Network Technology

- Quality of Service - 99.0% Availability, High Speed < 1 sec.
- Network and Physical – Public Broadband Internet

IESCA #11 Control Center to Customer Environment

- Quality of Service - 99.0% Availability, High Speed < 1 sec.
- Data Exchange - Smart Energy Profile

Home Area Network

A wireless or power line carrier Home Area Network (HAN) will be deployed by the customer to provide the private, in-home communications required for home/building automation, energy management, security, and entertainment.

IESCA #16h Intra-Customer Site Environment - Home

- Data Exchange - Smart Energy Profile, others
- Network and Physical – ZigBee Wireless HAN
- Network and Physical - Power Line Carrier HAN

IESCA #16c Intra-Customer Site Environment - Commercial

- Data Exchange - Smart Energy Profile, others
- Network and Physical – ZigBee Wireless HAN
- Network and Physical - Power Line Carrier HAN

IESCA #16i Intra-Customer Site Environment - Industrial

- Data Exchange - Smart Energy Profile, others
- Network and Physical - Power Line Carrier HAN

Private vs. Public Communication Infrastructure

Traditionally, the power utility communications infrastructure typically comprises multiple physically separate networks, each dedicated to support specific applications and functions. For example, a SONET/SDH based network is used to carry real-time SCADA traffic while engineers needing access substation information use dial-up modems. Further, a separate TDM-based network may exist to support PBX-based voice communications among the substations and control centers.

With the advent of new, high-speed communications technologies, the Communication Architecture, as presented, recommends that these multiple communications paths be consolidated into the Corporate IT WAN and that all KCP&L networks be implemented on private communications infrastructure.

Why Not the Internet

The public Internet is a very powerful, all-pervasive medium. It can provide very inexpensive means exchange information with a variety of other entities. The Internet is being used by some utilities for exchanging sensitive market information, retrieving power system data, and even issuing some control commands to generators. Although standard security measures, such as security certificates, are used, a number of vulnerabilities still exist.

By using the Corporate IT WAN, the KCP&L SmartGrid system designs can still leverage the vast amount of research and development into Internet Protocols (IP) and technologies. They will just be implemented over a private Intranet instead of the public Internet to minimize the exposure to cyber security attacks.

Role of Public Carriers

As information becomes increasingly vital to power system operations, utilities want to ensure continued support for these information flows, while providing greater insight into the state of the communications network and the computer systems in the field, reducing latency.

Where it has proven to be cost effective, KCP&L has chosen to construct and own significant portions of the WAN communications infrastructure. This includes a significant amount of fiber links in the metro and microwave links in the rural areas. Dedicated leased communication links have been used to provide the network path where KCP&L communications is not available. Although leased from a public carrier, the dedicated link is not impacted by other users of the carrier.

The FAN network to support DA and AMI significantly increases the number of nodes that must be connected to the network. There are two fundamental reasons for recommending that KCP&L construct and operate a private wireless FAN instead of using a public wireless carrier; operational reliability and financial.

Operational reliability is critical for the DA devices and functions. History has shown that during times of emergencies and natural disasters public carriers become congested and communications becomes unreliable. The public carriers have been unwilling, or unable, to guarantee communications during high usage times.

Using a public wireless carrier also creates additional ongoing operational costs. If we used wireless public carrier exclusively the Smarter Grid deployment would require at least 1000 AMI "take out points" and 4000 DA device connections at a cost of nearly $3 million per year. Using a 10yr life and a 12% cost of money this would equate to an upfront capital expenditure of approximately $15 million.

Data Management, Integration & Interoperability

This level designates the information technology systems needed to store the data provided through the communication infrastructure layer and allow their use by the relevant applications to transform it into information. Interoperability between systems is a critical issue at this level for applications to leverage the data collected and extract maximum value.

Data Management

Data Management Considerations

The amount of data being collected or capable of being collected will increase exponentially with the implementation of the Smart Grid. This rapid expansion of data management results from the fact that more field devices are being installed and that these field devices are becoming more "intelligent" both in what power system characteristics they can capture, and also in what calculations and algorithms they can execute which result in even more data.

As distribution automation extends communications to devices on feeders, as substation automation expands the information available for retrieval by substation planners, protection engineers and maintenance personnel, and as more power system asset information is stored electronically in Geographical Information, even more varieties and volumes of data will be need to be maintained and managed.

Data management is a complex issue, encompassing many aspects of data accuracy, acquisition and entry, storage and access, consistency across systems, maintenance, backup and logging, and security. Data management must address a complex set of issues which include the following services:

1. Validation of source data and data exchanges
2. Ensuring data is up-to-date
3. Management of time-sensitive data flows and timely access to data by multiple users
4. Management of data consistency and synchronization across systems
5. Management of data formats in data exchanges
6. Management of transaction integrity (backup and rollback capability)
7. Management of the naming of data items (namespace allocation and naming rules)
8. Data Accuracy
9. Data Acquisition
10. Data Entry
11. Data Storage and Access Management
12. Data Consistency across Multiple Systems
13. Database Maintenance Management
14. Data Backup and Logging
15. Application Management

No single cross-industry technology addresses all of these issues, but multiple solutions are available for different aspects. See IECSA Volume IV, Appendix F for discussion of each.

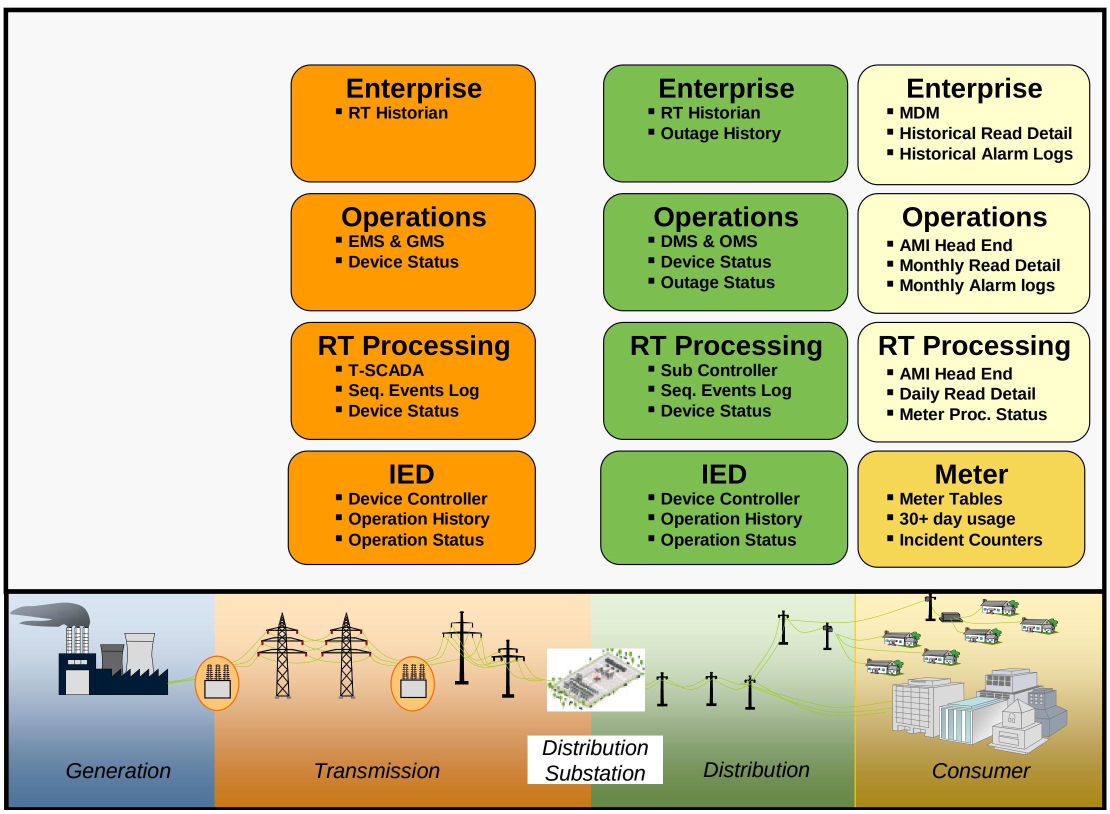
Data Management Architecture

This view presents the Data Management Architecture that will be implemented as the SmartGrid evolves. In traditional grid control systems all data management has been centralized. Data was collected remotely at the field RTUs and transported back to a central control center for use in applications, presentment, storage, or disposal. As deployment of SmartGrid expands several things are happening:

- The amount of data being collected or capable of being collected will increase exponentially.
- IED provide the ability to process data locally and take local actions independently.
- IEDs can also increase the amount of data needed to collect and actions to log and report
- Data storage is very inexpensive and has been added to IEDs, meters, and other field devices

Base on the current trends, the Data Management Architecture presented in Figure 6 is hierarchical and distributed, very complimentary to the hierarchical and distributed nature of the other architectural components.

Figure 6 – Smarter Grid Data Management View



The hierarchical levels are significant because data transfer between the levels is generally controlled to some degree. Data available at a higher level may only be an aggregated view of data available at a lower level. This does not mean that lower level data is unavailable, just that the detailed data has not been needed at the higher level to support normal business operations.

Data Management Principles

The Data Management Architecture presented is a complete opposite paradigm of traditional control systems. Figure x, presents the data management principles that should be used to guide the system designs when implementing this architecture.

		AMI Example	DA Example
1	Data should be processed as close to the collection point as possible.	Meter broadcasts use every 5 sec. to customer.	
2	IEDs and process controllers internally store data for limited periods to support local processing and higher level system needs.	Meter can store 45 days of TOU usage and midnight read data in meter memory.	
3	Data should only be communicated to another device or higher level if there is a real business need for the data.	Meter sends midnight read for all accounts; TOU only sent for specified accounts	
4	Data that is no longer needed is allowed to expire at the earliest possible time and at the lowest level.	Meter data is allowed to expire at the meter after 45 days	
5	At each level, data should be managed by the most appropriate data management technology.	At the system level, meter data should be managed by a MDM system.	
6	Data achievable should occur at the enterprise level using the most appropriate data archival technology		A real-time historian should be used to archive any real-time data that needs to be archived

Integration & Interoperability

Interoperability Goals - The ultimate goal of interoperability is to enable two independently developed devices to integrate their operations over a communications network. Interoperability has been defined as:

> *"The ability of two or more systems or components to exchange information and to use the information that has been exchanged"*[7]

While the concept appears simple on the surface, the complexity of the systems or components requires a substantial amount of agreement in the way they interact. Even relatively simple levels of interoperability require not only adherence to standards and agreement on use of those standards, but technicians are also necessary to participate in setting up and configuring equipment. Higher levels of interoperability are a fundamental requirement for SmartGrid systems and this includes the capabilities to enable the equipment to participate in the management of the system.

The concepts of 'Plug and Work' (or 'Plug and Play') require more sophisticated levels of interoperability. These capabilities enable you to plug in a new device, application, or system into an existing system, and the existing system automatically incorporates the new equipment. These levels of interoperability are strongly desired since it simplifies the human intervention required to manage systems. However, to achieve systems that are easier for humans to use requires a higher degree of internal sophistication. Interoperability and interworkability are terms that must be more tightly defined within the industry. The goal of interoperable systems can be very hard to achieve in a diverse environment with many different requirements, many different vendors, and a wide variety of standards. Interoperability is particularly difficult where legacy systems prevent the use of more modern approaches. No one answer exists on how to integrate these older, less flexible systems, but the following technologies and best practices can help toward that interoperability.

Key Points of Interoperability–An additional principle states that while it is possible to standardize everything, it is also possible to end up with so many standards that ultimately there are no standards. Ultimately, there must be a balance between components of a communications system that are rigidly standardized, and, those that are fairly flexible to be pioneered by market participants -- vendors, customers, etc.

For the SmartGrid, there will be an analogy between those key points of interoperability for power (60Hz, 120VAC, plug shape) that will be key to facilitating an explosion in goods and services that can interact using components referenced in the architecture. Some key points of interoperability required for the SmartGrid are.

- **Manufacturing IDs**–Globally unique identifiers for the source of a component in a utility or other enterprise system.
- **Serial numbers**–Globally unique identifiers for instances of products.
- **Standardized object models**–Standardized object models with 'well-known' names and formats for exchanging data among disparate applications and systems.
- **Metadata representation**–Metadata is data that describes data. The term 'Rose' could be a persons name, a flower, a color or an acronym. Metadata is the term that describes what the word Rose refers to in a given application. Metadata is a powerful concept that can be used for embedded devices to exchange information and achieve higher levels of interoperability. This 'data' that describes data permits users, applications, and systems to access or 'browse' the names and structures of object models in other systems as the key method for 'data discovery'.
- **Internet and industry standards**–Using the Internet and other industry standards to take advantage of the effort used to develop them, the resulting decrease in prices, and the interoperability provided by them.
- **Time synchronization over widespread geographic areas**–The ability to define a common mechanism to obtain reliable global time synchronization for devices of any level of complexity.

The DOE, NIST, and FERC Roles

The Department of Energy is the lead federal agency on the Smart Grid effort, and the National Institute of Standards and Technology (NIST) is coordinating the development of interoperability standards for the project. Interoperability standards are needed to ensure that software and hardware components from different vendors will work together seamlessly, while cyber security standards will protect the multi-system network against natural or human-caused disruptions.

The Energy Independence and Security Act (EISA) of 2007 charges NIST with *"primary responsibility to coordinate development of a framework that includes protocols and model standards for information management to achieve interoperability of smart grid devices and systems.*"

The EISA-2007 also provides a mandates to FERC. *"At any time the Institute [NIST] work has led to a sufficient consensus in the [FERC] Commission's judgment, the Commission shall develop, by rule, such standards and protocols as may be necessary to ensure smart-grid functionality and interoperability in interstate transmission of electric power, and regional and wholesale electric markets."*

NIST recently contracted with the Electric Power Research Institute, Inc. (EPRI) to help the agency develop an interim report on Smart Grid architecture and a standards roadmap. EPRI also will support consensus-building activities to create an initial slate of Smart Grid standards. By the end of 2009, NIST plans to submit these standards for review and approval by the Federal Energy Regulation Commission, which has jurisdiction over interstate transport and sales of electric power.

Evolving SmartGrid Interoperability Standards

This section presents evolving SmartGrid interoperability standards needed to store and move the data through the communication infrastructure layers from device to device, device to application, and between applications. With the work completed to date by NIST and EPRI, it appears that the standards presented here will form the basis of the NIST SmartGrid Interoperability Framework. The AMI and HAN integration standardization remains very polarized and will take longer for a standards path to materialize. Interoperability between systems is a critical issue at this level for applications to leverage the data collected and extract maximum value.

Common Information Model - IEC-61970

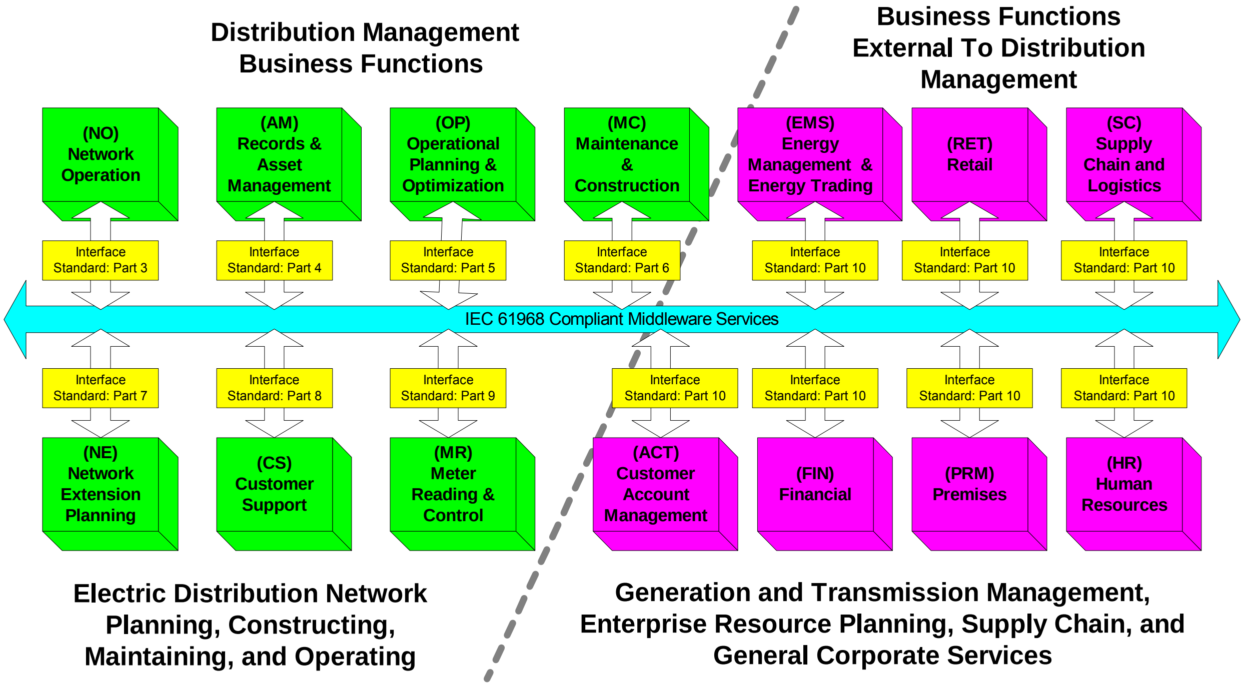
The IEC-61970 standard includes the Common Information Model (CIM), the Generic Interface Definition (GID). The purpose of the CIM is to produce standard interface specifications for "plug-in" applications for the electric utility industry. A "plug-in" application is defined to be software that may be installed with minimal effort and no modification of source code.

The CIM describes real-world objects in terms of classes, attributes, and relationships. The CIM contains object types such as substations, breakers, as work orders as well as other objects typically found in an control systems (EMS, SCADA, DMS) or work and asset management systems. Recently the CIM has been extended to include transmission reservation and energy scheduling information and work is ongoing to extend the CIM for additional distribution and customer energy management objects.

System Interfaces for Distribution Management: - IEC-61968

The IEC-61968, as depicted in Figure 7, is a 10 part standard that extends the CIM model for object and messaging definitions to support the enterprise back-office Distribution System Management functions of Asset Management (AMS), work management systems (WMS), Distribution Network Management (DNM), Outage Management Systems (OMS), Meter Data Management (MDM), Automated Meter Information (AMI), and Geographic Information Systems (GIS).

Figure 7 - IEC 61968-1 DMS Application Interface Reference Model



Inter-Control Center Communications - IEC-60870-6 (TASE.2)

The IEC-60870-6 Telecontrol Application Service Element 2 (TASE2) protocol (informally referred to as the InterControl Center Communications Protocol (ICCP)) was developed by IEC for data exchange over Wide Area Networks between a utility control center and other control centers, other utilities, power plants, and substations.

TASE.2 is used in almost every utility for inter-control center communications between SCADA and/or EMS systems. Since it was first in the mid-1990s, before the CIM object model, it is limited to use to the object model that is in the specification.

Inter-Device Communication IEC-61850

The IEC-61850 standard describes physical field devices such as circuit breakers, protection relays, capacitor controllers, and in recent additions distributed energy resources such as wind turbines, diesel generators, and fuel cells. The 61850 Object Models are 'nouns' with predefined names and predefined data structures. Objects are the data that is exchanged among different devices and systems.

IEC-61850 was originally developed for intra-substation communications between devices and control systems. The IEC-61850 standard includes a Substation Configuration Language (SCL) to define the inter-relationship of the substation equipment to each other and the ability for the protocol to 'self-describe' the data to be reported by a particular device.

Work is ongoing to harmonize the IEC-61870 and IEC-61850 standards and extend the IEC-61850 standard to include distribution line devices, distributed energy resources and customer energy management objects.

Inter-Device Communication DNP3-IP

DNP was developed as a three-layer asynchronous protocol suitable for use on slow serial links and radios. It incorporates the best features of the many proprietary protocols that preceded it and therefore has gained wide support and continues to be the dominate protocol in use throughout the North American electric utility industry.

In 2000, the DNP technical Committee defined a specification for carrying DNP3 over TCP/IP and UDP/IP. Because the WAN/LAN version is essentially the serial DNP3 encapsulated, this makes it possible to connect serial DNP3 devices to WAN/LAN DNP3 devices using a variety of networking technologies.

DNP3 does not support the CIM object models therefore; it is considered to be a transitional protocol and may continue to be used as the SmartGrid evolves supporting existing legacy devices that cannot be replaced economically.

Home Area Network - Smart Energy Profile

The ZigBee Alliance is an association of companies working together to enable reliable cost effective, low-power, wirelessly networked, monitoring and control products based the IEEE 802.14.4 standard. The alliance developed the "Smart Energy Profile", a set of messages for managing energy and communicating with thermostats and other smart appliances

Overall, the AMI and HAN integration standardization remains very polarized and will take longer for a standards path to materialize. However, The Smart Energy Profile is gaining considerable traction as the application messaging protocol of choice. HomePlug, a major home-automation, competitor has announced that it will adopt the Smart Energy Profile for it's power-line carrier based system. Smart Energy Profile 2.0 is currently under development and when released, it will contain the messaging to support plug-in electric vehicles.

Security View

This view presents the security requirements and technologies envisioned to secure the SmartGrid.

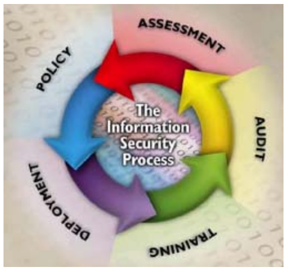
Securing the SmartGrid

'Security by obscurity' is no longer an acceptable solution in the electrical power industry. Protection and securing of networked communications, intelligent equipment, and the data and information that are vital to the operation of the future SmartGrid is one of the key drivers behind developing this Architecture Security View. Cyber security faces substantial challenges both institutional and technical. This discussion is intended to provide context to this complex topic as well as providing a pathway by which the company can work to develop a robust portfolio of technologies to meet the critical issues that encompass security. Securing the SmartGrid faces multiple challenges from the following major trends:

- Need for greater levels of systems integration with a variety of business entities
- Increased use 'internet-based' infrastructures that will comprise the future energy system
- The need for appropriate integration of existing or “legacy” systems with future systems
- Growing sophistication and complexity of integrated distributed computing systems
- Growing sophistication and threats from hostile communities

Security functions are integral to the designs of systems and must be planned and designed into systems from the start. Planning for security, in advance of deployment, will provide a more complete and cost effective solution. Additionally, advanced planning will ensure that security services are supportable (may be cost prohibitive to retrofit into non-planned environments. This means that security needs to be addressed at all levels of the architecture.

Security is an ever evolving process and is not static. It takes continual work and education to help the security processes keep up with the demands that will be placed on the systems. Security will continue to be a race between corporate security policies/security infrastructure and hostile entities. The security processes and systems will continue to evolve in the future. By definition there are no communication connected systems that are 100% secure. There will always be residual risks that must be taken into account and managed.



Security Domains

The far reaching and complex nature of the SmartGrid dictates that no-single security policy can be developed to properly secure the SmartGrid. The hierarchical nature of the technologies presented in the Communications Network and Grid Monitoring & Control Architecture views provides for the security “check-points” between control and network layers that may have different security requirements. Therefore, it is a natural extension for the Security Architecture to be constructed around "Security Domains".

A "Security Domain" represents a set of resources (e.g. network, computational, and physical) that share a common security requirements and risk assessment. For example; within the 'bulk power system' there are two distinct Security Domains: NERC-CIP and NERC-nonCIP.

While having different security requirements, all Security Domains will be secured and managed through a consistent set of security policies and processes. Secure connectivity, data encryption, firewall protection, intrusion detection, access logging, change control and the audit reports associated with these applications will likely be required for all SmartGrid Security Domains.

The following sections identify the security domains that must be addressed in SmartGrid Security planning and development.

SD0 Internet

- Policy Mgt
- Ownership Many Parties
- Net. Mgt. Many Parties
- End Device Access Consumer

SD1 HAN

- Policy Consumer
- Ownership Consumer
- Net. Mgt. Consumer
- End Device Access Consumer

SD2 AMI-WAN

- Policy Utility
- Ownership Utility & Public Carrier
- Net. Mgt. Utility IT Telcom
- End Device Access Utility Metering Personnel

SD3 DA-WAN

- Policy Utility
- Ownership Utility
- Net. Mgt. Utility IT Telcom
- End Device Access Utility Construction & Eng. Personnel

SD4 Substation SPN

- Policy Utility
- Ownership Utility
- Net. Mgt. Utility IT Network & Telcom
- End Device Access Utility Relay & Eng Personnel

SD5 Corp WAN

- Policy Utility
- Ownership Utility & Leased Private
- Net. Mgt. Utility IT Network & Telcom
- End Device Access Utility IT Network & Telcom

SD6 Corp. LAN

- Policy Utility
- Ownership Utility & Leased Private
- Net. Mgt. Utility IT Network
- End Device Access Any KCPL Employee

SD7 DNMS LAN

- Policy Utility
- Ownership Utility
- Net. Mgt. Utility IT Network
- End Device Access Authorized KCPL Employee

SD8 FERC/NERC-nonCIP

- Oversight FERC/NERC
- Ownership Utility
- Net. Mgt. Utility IT Network
- End Device Access Authorized KCPL Employee

SD9 FERC/NERC-CIP

NERC-CIP compliance is mandated for the bulk power system.

- Oversight FERC/NERC
- Ownership Utility
- Net. Mgt. Utility IT Network
- End Device Access Limited-Authorized KCPL Employee.

Not all data are equal when it comes to sensitivity to security threats. The key to assessing the sensitivity of data is to determine the impact, both financial and societal, on compromising its security, and to determine the risk of that compromise occurring. For instance, the financial and societal impact of eavesdropping on the meter readings of a single residential home is far less than the impact of issuing unauthorized breaker-trip commands to high voltage transmission lines. Therefore, the primary need is the assessment of financial and societal costs of different security vulnerabilities, along with the assessment of the financial and societal costs of implementing security measures. The IECSA security strategy is documented in Appendix A for those technologies that have identified the issues in their respective environments (e.g. IEC61850). The security strategy for other technologies/applications will have to be developed based on the requirements of the particular application and using the technologies and practices found in Appendix A.

Regulatory View

This view presents the regulatory influences and requirements that can become key to any successful SmartGrid deployment. \

Economic and Regulatory Policy

Business organizations require that the political and regulatory policies, that govern commerce provide the proper environment and/or incentives to build business relationships with other organizations, some of which may be considered competitors. This includes national, stat and local governalce. Interoperability betweek organizatons in differerent state and geographical regions may require regulatory alignment at the state level or a national policy to provide an environment conductive for business interoperability. In addition, policy can provide incentive and remove impediments for regional or national structures that facilitate interoperation.

Jurisdictional Oversight

Utilities require that the political and regulatory policies of the jurisdictions within which they operate, provide the proper environmt and/or incentives to make the required investments in SmartGrid technologies and programs, many of which may be contrary to traditional utility engineering and operating practices. Proper regulatory policy can provide incentives and remove impediments for these and facilitate the transition to a modern SmartGrid.

Transmission Grid Oversight

For KCP&L, the jurisdictional aspects of SmartGrid realated to the transmission grid are complicated for KCP&L by the fact that it operates in two states, each with differing laws, regulations, and regulatory commissions and by multiple regional and federal agencies.

FERC

The Federal Energy Regulatory Commission (FERC) is an independent federal agency that regulates the interstate transmission of electricity, natural gas, and oil. FERC has jurisdictional authority of the KCP&L's electric transmission grid.

- Regulates the transmission and wholesale sales of electricity in interstate commerce;
- Ensures the reliability of high voltage interstate transmission system;
- Monitors and investigates energy markets;
- Uses civil penalties and other means against energy organizations and individuals who violate FERC rules in the energy markets;
- Licenses and inspects private, municipal, and state hydroelectric projects;
- Oversees environmental matters related to natural gas and hydroelectricity projects and major electricity policy initiatives.

NERC

North American Electric Reliability Corporation (NERC) develops reliability standards for the North American bulk power system that are adopted by FERC. Along with the Regional Reliability Organizations, NERC has the legal authority, from FERC, to enforce compliance with NERC Reliability Standards, which it achieves through a rigorous program of monitoring, audits and investigations, and the imposition of financial penalties and other enforcement actions for non-compliance.

SPP

The Southwest Power Pool (SPP) is a Regional Transmission Organization, mandated by the FERC to ensure reliable supplies of power, adequate transmission infrastructure, and competitive wholesale prices of electricity. As a NERC Regional Reliability Organizaton, SPP oversees compliance enforcement and reliability standards development. SPP has member utilities in nine states including KCP&L and KCP&L-GMO.

State Regulatory Commissions

The State Regulatory Commissions have jurisdictional authority many aspects of the transmission grid including the approval for the physical construction of electric generation and transmission facilities; except for hydropower and certain electric transmission facilities located in National interest electric transmission corridors.

Distribution Grid Oversight

For KCP&L, the jurisdictional aspects, of SmartGrid related to the distribution grid, are complicated by the fact that we operate in two states, each with differing laws, regulations, and regulatory commissions.

The Missouri Public Service Commission (MO-PSC) regulates investor-owned electric, steam, natural gas, water and sewer and telephone companies. Its mission is to ensure Missouri consumers have access to safe, reliable and reasonably priced utility service while allowing those utility companies under our jurisdiction an opportunity to earn a reasonable return on their investment.

The mission of the Kansas Corporation Commission (KCC) is to protect the public interest through impartial and efficient resolution of all jurisdictional issues. The agency shall regulate rates, service and safety of public utilities, common carriers, motor carriers, and regulate oil and gas production by protecting correlative rights and environmental resources.

State Regulatory Commissions

While the MO-PSC and KCC have different areas of responsibly and different styles of proceeding, both have jurisdictional authority over the utilities and operation of the electric delivery grid in their respective states. They each:

- regulate the retail electricity and natural gas sales to consumers.
- regulate the electric service territory of the utility
- determine if investments are prudent and set reasonable rate of return.

Both state commissions are currently considering three (3) new PURPA requirements that related directly to the SmartGrid:

1) Rate Redesign to promote Energy Efficiency;
2) SmartGrid Investment; and
3) SmartGrid Information.

KCP&L has recommended that the commissions use a collaborative, workshop process to develop the framework for considering these issues. The IL commission mandated that Ameren and Comm. Edison participate in a formal state-wide SmartGrid Road Map.

Successful collaboration with the Commissions, Legislatures, and Consumer Organizations on transitional issues will be key to achieving the level of consumer acceptance, participation and enthusiasm in the new energy management concepts needed to make the SmartGrid deployment a success. Inverted Block rate structures will be needed to promote energy efficiency and effective Time of Use rates will be needed to promote shifting energy consumption off-peak. The new standard AMI meters are designed to easily support TOU rates with 4-daily usage times and 4-seasonal periods allowing for very flexible rate implementations.

KCP&L SMARTGRID ROADMAP

WHAT IS A SMARTGRID ROAD MAP

In the previous section the SmartGrid Architecture for KCP&L was presented. Realizing that the "SmartGrid", in complete vision, cannot be built today, but will instead develop over time, a SmartGrid Road Map presents a plan for implementing the vision and functionality of the SmartGrid over time.

DEVELOPING A SMARTGRID ROAD MAP

The "SmartGrid", in complete vision, cannot be built today, but will instead develop over time. Most utilities have a similar vision for an ultimate SmartGrid but will take different paths and time-lines in their respective SmartGrid deployments. These paths will be influenced by regulatory and business drivers and the mix of technologies that a company has currently installed. The SmartGrid Road Map presented here is a plan for implementing the vision and functionality of KCP&L's SmartGrid over time.

Strategic Drivers

- The Sustainable Resource Strategy component of the GPE Strategic Intent.
- Delivery's Strategic Focus on Cost Performance and Customer Satisfaction

Short-Term Business Drivers

- Economy downturn, rate case slippage, and the budget constraints through 2010
- Federal SmartGrid grants through the ARRA Stimulus package.
- Elevate GMO distribution monitoring and control to KCP&L levels to improve reliability and operational costs.
- Implement AMI in GMO to reduce operational costs and provide GMO customers access to same level of information available to KCP&L customers.
- KCP&L AMR contract with CellNet expires Aug. 2014
- Expand of EE and DR programs to GMO customers
- Provide the Net-metering support for solar and other renewable forms of generation to meet the MO Prop-C renewable energy mandate.
- Leverage existing and planned budget dollars to fund SmartGrid deployments where possible.

DEVELOPING THE ROAD MAP

In developing this SmartGrid Roadmap, the SmartGrid staff studied several SmartGrid pilot projects and their respective road map documents. Many of these are focused on AMI and selling SmartGrid as a means of empowering consumers to lower their usage and correspondingly their utility bills. While this may ultimately be the case, with KCP&L's historically low rates, we do not believe our customer are ready to embrace these load shifting initiatives on a large scale. KCP&L's customers continue to be more focused on reliability and quality of service issues.

Our approach

The benefits of the SmartGrid are obvious and the costs to implement it will be considerable. It is important that we 'get it right' and maximize the benefits we obtain as we make the grid smarter and add functions and capabilities. From a regulatory perspective it is also important that the costs associated with the technology rollout be borne by those consumers who receive the benefits. In our analysis, we have concluded that we should not focus immediately on the end-user interactions; rather we should begin on the operational side first. If we focus on the distribution grid operations and AMI, we can streamline operations, thus reducing costs, and gain more control of the grid, thus increasing reliability.

Road Map Principles

The SmartGrid Department developed the following principles to guide the development of the SmartGrid Road Map.

- Support strategic and short-term business drivers.
- There is no SmartGrid silver bullet technology. SmartGrid projects should implement technology that comply with the defined architecture and provide the greatest operational benefits.
- Leverage the Federal Smart Grid demonstration project and investment grant funding authorized by the Energy Independence and Security Act of 2007 (EISA)..
- 10 year time-line to deploy existing and emerging SmartGrid technologies
- In 2020 the SmartGrid infrastructure should be able to support advanced grid technologies and potential customer programs deployed across the grid.
- Initial priority should be on projects that that deploy SmartGrid enabling technologies and leverage existing AMR and DA competencies. AMI is considered an enabling technology.
- Consumer facing programs should be preceded with a consumer education program and a well structured pilot of the technology to evaluate consumer participation and benefits.
- The Road Map should be reviewed periodically as business drivers change; revisions made to the Architecture; or new capabilities or opportunities emerge in the industry.

The Road Map

The SmartGrid Road Map presented in the following table is a plan for implementing the vision and functionality of KCP&L's SmartGrid.

	2009		2010		2011		2012		2013		2014		2015		2016		2017		2018	
Stimulus Projects																				
- Grant Development																				
- Extend WAN District Subs		e	d	d	d	d	a	a												
- GMO District DA/DMS		e	d	d	d	d	a	a												
- GMKCPL Dist. DA/DMS/D-SCADA				d	d	d	a	a												
- GMO AMI		e	d	d	d	d	a	a												
- KC Green Zone Pilot		e	d	d	d	a	a	a												
- Battery Pilot			e	d	a	a														
- Extend DA Field Mon & Control							d	d	d	d	d	d	d	d	d	d	d	d	d	d
- Expand AMI Operation Support					e	e	d	d												
					e															
KCPL Metro AMR/DA Upgrade																				
- AMR Contract Expires												♦								
- Extend WAN to Metro Subs					e	e	d	d	d	d	d									
- DA moved to DMS/D-SCADA					e	e	d	d	d	d	d									
- OMS moved to DMS							e	e	d	d	a									
- KCPL AMI Upgrade									e	d	d	d	d	a						
TMS/SCADA incorporate PMU						e	d	d	d	d	a									
Cunsumer Home Automation																				
- Home Automation Pilot							e	e	d	d	a	a								
- Home Automation Programs											e	e	d	d	d	d				
DR & DER Integration																				
- Solar Rebates			d	d	d	d	d	d	d	d	d	d	d	d	d	d	d	d	d	d
- DMS DR & DER Mgt											e	e	d	d	d	d				
Retail Rate Design																				
- flat/inverted rate structure					e	e	d	d												
- TOU rate redesign 4season-4tod									e	e	d	d								
- Day Ahead pricing programs													e	e	d	d				
- RT pricing programs																	e	e	d	d
	2009		2010		2011		2012		2013		2014		2015		2016		2017		2018	

Applications

Technologies,

Smart Grid Characteristics

	Smart Grid Characteristics	**Future**	**Pilots Possible**	**Deployment Possible**	
1	*Digital information and controls technology to improve reliability, security, and efficiency of the electric grid*			DMS Sub Auto ADA	
2	*Dynamic optimization of grid operations and resources, with full cyber-security*	evolving			
3	*Deployment and integration of distributed resources and generation, including renewable resources*	evolving	Solar Battery		
4	*Development and incorporation of demand response, demand-side resources, and energy-efficiency resources*				
5	*Deployment of ''smart'' technologies 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.*				
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."*				