RECOVERY ACT – SMARTGRID REGIONAL DEMONSTRATION
TRANSMISSION AND DISTRIBUTION (T&D) INFRASTRUCTURE

KCP&L GREEN IMPACT ZONE SMARTGRID DEMONSTRATION

FINAL TECHNICAL REPORT

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WORK PERFORMED UNDER AGREEMENT

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SUBMITTED BY

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EXECUTIVE SUMMARY

Individual components in Kansas City's Green Impact Zone wouldn't spur much industry buzz: 14,000 customers, 11 highly automated feeders, a modernized substation and a variety of customer programs.

However, connecting them all with equipment, integrated software and experienced personnel — as KCP&L did for five years, as part of a Smart Grid Demonstration Project financed along with the U.S. Department of Energy (DOE) — created a model that has produced comprehensive data, insights and expectations that form an informational foundation. This foundation is expected to guide effectiveness of future smart grid implementations in the area, region and nation.

The primary objectives of the KCP&L Green Impact Zone Demonstration Project illustrated in Figure 1 were twofold: (a) to demonstrate, test, and report on the feasibility of combining, integrating, and applying existing and emerging smart grid technologies and solutions to build innovative smart grid solutions; and (b) to demonstrate, measure, and report on costs, benefits, and business model viability of the demonstrated solutions. KCP&L gained valuable learning and experience in the implementation and performance of these technologies and systems, as well as insights into the operational, consumer, environmental, and societal benefits that can be achieved.

This Final Technical Report details performance of the full project, which called for deployment of a fully integrated smart grid demonstration in an economically challenged area of Kansas City, Missouri. The $58 million project called for deploying an end-to-end smart grid that included advanced metering infrastructure; renewables; storage; leading edge substation and distribution automation and controls; demand response; home energy management interfaces; and innovative customer programs and rate structures. Through its observations, conclusions and appendices, this report provides an informational schematic for utilities and other parties interested in smart grid implementation.

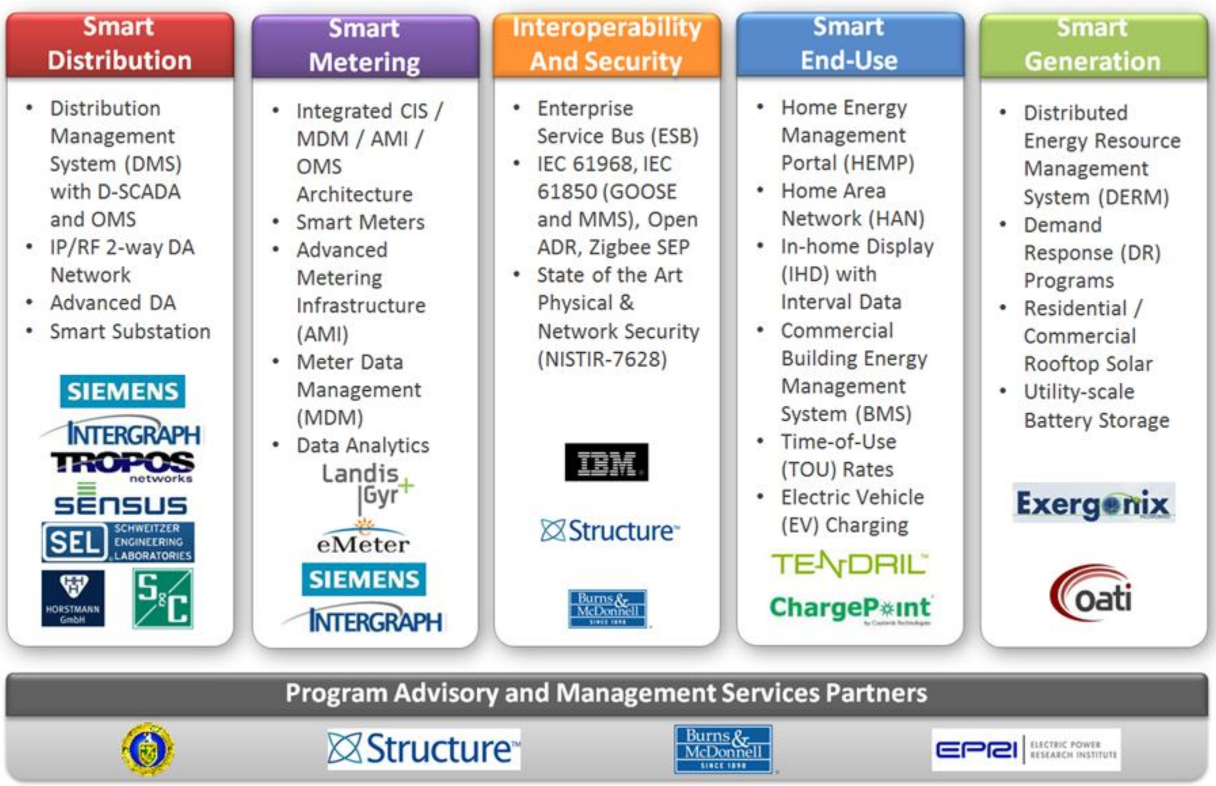
Figure 1: KCP&L SmartGrid Demonstration Project Scope

Following the DOE's Guidance for Technology Performance Reports, KCP&L developed this expansive, comprehensive document that covers all aspects of the SmartGrid Demonstration Project. The bulk of the report is contained in four separate sections, with each successive one built upon the contents of the preceding section.

First is Section 1, crafted early on as an outline of the project's general scope – including the technologies to be implemented and the vendors providing the technology components. This section includes KCP&L's company background, the project geography, schedule and team. It also includes a high-level overview of the SGDP systems and technologies. A graphical depiction of the project scope is shown above in Figure 1.

Next, Section 2 outlines how the scope was implemented – creating a fully functional smart grid, one ready for operational testing. This section included the deployment of new systems, the building of interfaces between systems, and the integration of new and legacy technologies. Section 2 provides the technical approach and the systems implementation overview for each subproject. It includes system implementation test plans and operational demonstration/test plans. Figure 2 below shows the KCP&L project categories, subprojects and components, and the associated project partners and significant contributors.

Figure 2: KCP&L SmartGrid Categories and Project Components



Section 3 takes the next step - using a functional smart grid to run the actual operational demonstrations defined for the project. This section includes results from the Interoperability, Cyber Security, and Education & Outreach subprojects. It also includes operational test results for the operational demonstrations shown in Table 1 below. Finally, it contains the metrics and benefits analysis.

Section 4 pulls everything together by summarizing project conclusions, lessons learned, and technology gaps. It also covers the commercialization resulting from vendor/partner project participation and the project's impact on KCP&L's future plans for smart grid deployment. This section identifies strengths, exposes weaknesses, and outlines opportunities for the industry going forward.

The utility's Green Impact Zone SmartGrid Demonstration Project generated focused observations, outlooks and technology gaps because of its wide-ranging structure: Rather than focusing on a specific technology, KCP&L's project examined and analyzed a broad spectrum of smart grid offerings. Putting all the pieces together allowed the utility to see how the components would work, together, in a real-world environment.

Table 1: KCP&L SmartGrid Operational Demonstrations

DOE Smart Grid Function	KCP&L Operational Demonstration
Automated Voltage & VAR Control	Integrated Volt/VAR Management
Real-Time Load Transfer	Feeder Load Transfer
Automated Feeder & Line Switching	Fault Isolation & Service Restoration
Automated Islanding & Reconnection	Feeder Islanding with Grid Battery
Diagnosis & Notification of Equipment Condition	Substation Protection Automation
	Asset Condition Monitoring
	Substation Hierarchical Control
Real-Time Load Measurement & Management	Automated Meter Reading
	Remote Meter Disconnect/Re-Connect
	Outage Restoration with Power Status Verification
	Demand Response Events
Customer Electricity Use Optimization	Historical Interval Usage Information
	In-Home Display
	Home Area Network
	Time-of-Use Rate
Distributed Production of Electricity	Distributed Rooftop Solar Generation
Storing Electricity for Later Use	Electric Energy Time Shift
	Electric Supply Capacity
	T&D Upgrade Deferral
	Time-of-Use Energy Cost Management
	Electric Service Reliability
	Renewable Energy Time Shift
	PEV Charging

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1 SCOPE [1]

This document represents the Final Technical Report for the Kansas City Power & Light Company (KCP&L) Green Impact Zone SmartGrid Demonstration Project (SGDP). The KCP&L project is partially funded by Department of Energy (DOE) Regional Smart Grid Demonstration Project cooperative agreement DE-OE0000221 in the Transmission and Distribution Infrastructure application area.

This Final Technical Report summarizes the KCP&L SGDP as of April 30, 2015 and includes summaries of the project design, implementation, operations, and analysis performed as of that date.

1.1 PROJECT ABSTRACT

Kansas City Power & Light (KCP&L) is known for its commitment to community engagement and its ability to bring together diverse stakeholder groups to develop regional energy solutions. In 2007, KCP&L won the Edison Electric Institute's top award for innovation and contribution to the advancement of the electric industry. In addition, KCP&L is the only utility in the U.S. to reach an agreement with the Sierra Club in pursuing renewable energy and energy efficiency projects while building a high-efficiency coal generating station. Recognizing the need for a new approach to electricity generation, transmission, and distribution, KCP&L was awarded a DOE Regional SGDP cooperative agreement to deploy a fully integrated SmartGrid Demonstration in an economically challenged area of Kansas City, Missouri. The project is investing over $58 million to explore potential benefits to customers and the local grid and provide technology learning and advancement to the entire industry. Of the total investment, the DOE Regional SGDP cooperative agreement is providing approximately $23.9 million.

For the SGDP, KCP&L is deploying an end-to-end smart grid that will include advanced renewable generation, storage resources, leading edge substation and distribution automation and controls, energy management interfaces, and innovative customer programs and rate structures. The SGDP is focused on a subset of the area served by KCP&L's Midtown Substation, impacting approximately 14,000 commercial and residential customers across five square miles.

KCP&L's project complies with the DOE's funding guidelines and introduces commercial innovation with a unique approach to SmartGrid development and demonstration:

- First, this project truly creates a complete, end-to-end smart grid – from smart generation to smart end-use; it will deliver improved performance focused on a major substation in an urban location.
- Second, it introduces new technologies, applications, protocols, communications, and business models that will be evaluated, demonstrated, and refined to achieve improved operations, increased energy efficiency, reduced energy delivery costs, and improved environmental performance.
- Third, it involves a best-in-class approach to technology integration, application development, and partnership collaboration, allowing KCP&L to advance the progression of complete smart grid solutions, with interoperability standards, rather than single, packaged applications.
- Finally, KCP&L's SGDP will provide the critical energy infrastructure required to support a targeted urban revitalization effort—Kansas City's Green Impact Zone.

The project introduces new technologies in the substation and the distribution network as well as advanced renewable resources and large-scale energy storage to supply electricity and offset peak electrical demand. Finally, end users will be provided detailed usage information, digital tools, and innovative programs to empower them to optimize energy consumption and bill savings.

The Green Impact Zone (www.greenimpactzone.org) is the vision of Rep. Emanuel Cleaver II (D-MO) and will be a model for urban renewal and sustainability. The City of Kansas City and the Mid-America Regional Council have also taken lead roles in the effort. Through KCP&L's participation, innovators in today's SmartGrid landscape such as Siemens, OATI, Landis+Gyr, Intergraph, EPRI, Tendril, and Exergonix (formerly Kokam America) have signed-on to provide equipment, technical expertise, and in-kind financial support. A key component of the project is enhancing collaboration between public and private stakeholders. KCP&L believes the SGDP will foster an environment for increased employment opportunities, broad economic development, and reinvestment in the area.

By demonstrating an end-to-end solution, KCP&L will be able to test, evaluate, and report on a complete suite of smart grid benefits that include greater energy efficiency, reduced cost, improved reliability, more transparent and interactive information, and an improved environmental footprint. KCP&L believes this project will serve as a blueprint for future smart grid implementations and will accelerate the realization of the "utility of the future" that safely delivers reliable electricity with greater efficiency, reduced costs, and improved environmental performance.

1.2 Project Overview

1.2.1 Project Objectives

The primary objective of the SGDP is twofold: (a) to demonstrate, test, and report on the feasibility of combining, integrating, and applying existing and emerging smart grid technologies and solutions to build innovative smart grid solutions and (b) to demonstrate, measure, and report on the costs, benefits, and business model viability of the demonstrated solutions. The proposed technologies and solutions will be evaluated both individually, and as part of a complete end-to-end integrated smart grid system in a defined geographical area. The project will demonstrate certain operational, economic, consumer, and environmental benefits that can be enabled by single smart grid technologies and further enhanced by integrated solutions as proposed for this demonstration.

The objectives of individual initiatives are focused on implementing a next-generation, end-to-end smart grid that will include distributed energy resources, enhanced customer facing technologies, and a distributed-hierarchical grid control system.

1.2.1.1.1 Interoperability

The KCP&L SGDP interoperability objective is to implement an integrated end-to-end solution that demonstrates interoperability of the key smart grid components and incorporates elements of seven (7) of the eight (8) priority areas identified by FERC and NIST in the. NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 2.0 (NIST Smart Grid Framework):

- Demand Response and Consumer Energy Efficiency,
- Electric Storage,
- Electric Transportation,
- Advanced Metering Infrastructure,
- Distribution Grid Management,
- Cyber Security, and
- Network Communications.

This demonstration will implement a distribution network management system, substation and distribution automation systems, distributed resource and demand-side management systems, advanced metering infrastructure, and customer-based energy management and behind-the-meter resources and loads. The proposed solution architecture follows the EPRI IntelliGrid^{SM} Architecture and GridWise Architectural Council recommendations, as well as the NIST Smart Grid Framework.

1.2.1.1.2 Cyber Security

One of the objectives of the KCP&L SGDP is to evaluate and demonstrate end-to-end cyber security and incorporate the appropriate NIST cyber security standards and emerging industry security profiles, namely the NISTIR-7628 and UCAIug Security Profiles for Distribution Management and Advanced Metering Infrastructure. Over the course of the project to date, the project team has assessed the applicability of these standards and profiles and has adopted and/or augmented these standards as deemed appropriate.

The project team has taken cyber security considerations into account during each phase of the KCP&L SGDP infrastructure development both from an IT and grid infrastructure perspective. KCP&L has also chosen to implement the SGDP using a private communications architecture wherever practical. By utilizing the Corporate IT Wide Area Network (WAN) and utility-owned Field Area Network (FAN), the communication between KCP&L SmartGrid systems can leverage the vast amount of industry research and development for IP-based technologies. Another benefit of utilizing private networks instead of the public Internet for internal communication is to minimize vulnerability to cyber security attacks.

1.2.1.1.3 Education & Outreach

KCP&L's SGDP and associated partnerships in the Green Impact Zone create a tremendous opportunity for customers, the region, and the entire country to understand the value of advanced energy distribution and load management while providing reinvestment in Kansas City's urban core. Successful implementation of the KCP&L SGDP will require a steadfast commitment to effective stakeholder-focused communication.

There are three primary communications objectives for KCP&L's SGDP:

- Educate and engage customers in the project area, including the Green Impact Zone, about how SmartGrid investments will ultimately impact and benefit them, and then influence behavior and encourage participation in energy usage management
- Inform the remainder of KCP&L's customer base about how SmartGrid investments could ultimately impact and benefit them
- Share information with the broader utility industry on the progress and outcome of the project

Just as the SGDP is being deployed in a series of phases, so too is the public education and outreach plan. In 2010, the goal was to create general project awareness and understanding through face-to-face interaction, customer engagement, and the introduction of new SmartGrid tools. As the project moved into 2011 and beyond, the communications efforts become even more targeted as customer segments emerge and product adoption increases. At this point, KCP&L will begin to analyze and evaluate customer behaviors, attitudes, and channel preferences as well as the messaging mix that is most effective. In addition, the grid focused components of the project will be introduced to customers to help them better understanding the complexity and potential value of these investments and transformations.

1.2.1.1.4 SmartMetering

The primary objective of the SmartMetering subproject is to develop and demonstrate state-of-the-art integrated Advanced Metering Infrastructure (AMI) and Meter Data Management (MDM) systems that support two-way communication with 14,000 SmartMeters in the SGDP area and that integrate with other enterprise systems such as Customer Information System (CIS), Distribution Management System (DMS), Outage Management System (OMS), and Distributed Energy Resource Management (DERM) system. The SmartMetering infrastructure will provide the technology basis for recording customer and grid data that will be used to measure many SmartGrid benefits.

This new SmartMetering implementation will enable and quantify the following benefits:

- Reduced operating expenses through remote connect/disconnect capabilities
- Improved accuracy and frequency of meter reads
- Improved accuracy of meter inventory and reduction in untracked meters
- Increased success rate of automated reads relative to existing one-way AMR
- Improved outage handling relative to existing AMR technology with increased outage notification success rates and new power restoration messages
- Enables real-time, two-way communication for demand response program control initiation and verification of program participation

The SmartMetering technology will also provide advanced meter-to-device communications to facilitate in-home display, home energy management systems, and other consumer facing programs.

1.2.1.1.5 SmartEnd-Use

The primary objective of the KCP&L SmartEnd-Use subproject is two-fold. This subproject will achieve a sufficient number of consumers enrolled in a variety of consumer facing programs to 1) support the DERM development and demonstration, and 2) measure, analyze, and evaluate the impact that consumer education, enhanced energy consumption information, energy cost and pricing programs, and other consumer based programs have on end-use consumption. KCP&L has identified several secondary objectives for the suite of SmartEnd-Use programs expected to be deployed in the Demonstration Area:

- Improve customer satisfaction by increasing awareness and providing cost-saving opportunities
- Improve KCP&L’s capacity to serve customers through increased knowledge of customer behavior and usage patterns
- Demonstrate potential to reduce residential peak load profiles and reduce the need for future system capacity expansion by incenting off peak energy usage
- Pilot novel time-of-use (TOU) rate programs designed to incent consumer energy usage reduction during peak periods

By achieving these objectives, the project team expects to demonstrate how the integration of a broad suite of innovative efficiency and rate programs into a complete SmartGrid solution can enhance the overall benefits of the solution and optimally leverage the additional technical and operational capabilities that are enabled by the pilot investment.

1.2.1.1.6 SmartSubstation

The primary objective of the SmartSubstation subproject is to develop and demonstrate a fully automated; next-generation distribution SmartSubstation with a local distributed control system based on IEC 61850 protocols.

This new SmartSubstation demonstration will enable and quantify the following expected benefits:

- Improved real-time operating data on critical substation equipment
- Reduced O&M costs of relay maintenance
- Improved reliability through automation

By achieving these objectives, the project team expects to demonstrate Advanced Distribution Substation Automation with full substation automation with local automation controllers, operator interfaces, and other benefits of integrated intelligent electronic relays such as peer-to-peer communication, intelligent bus throw-over, fault recording, fault location, circuit breaker monitoring, and more efficient maintenance.

1.2.1.1.7 SmartDistribution

The primary objective of the SmartDistribution subproject is to develop and demonstrate a next generation Distribution Management System architecture that includes a fully automated Distributed Control and Data Acquisition (DCADA) SmartSubstation controller that incorporates a Common Information Model (CIM) based model of the local distribution network and performs local grid assessment and control of individual intelligent electronic device (IED) field controls. The DMS and DCADA will provide the operational backbone of the system supporting significant levels of automation on the feeders, complex and automated feeder reconfiguration decisions, and tightly integrated supervision with the Control Centers. The DMS serves as the primary point of integration for the grid facilities and network management functionality including Distribution Supervisory Control and Data Acquisition (D-SCADA) systems, Distribution Network Applications (DNA) systems, Outage Management Systems (OMS), Distributed Energy Resource Management (DERM) systems, Geographic Information Systems (GIS), and other supporting systems.

This new SmartDistribution demonstration will enable and quantify the following benefits:

- Improved service reliability by reducing the frequency and duration of outages
- Reduced frequency of momentary outages
- Reduced operational expenses through automation and remote control
- Reduced maintenance expenses through predictive maintenance strategies

In achieving the above objectives, the project team expects to demonstrate a family of automatic, distributed First Responder distribution grid monitoring and control functions:

- Substation and feeder load profile metering at 15 minute intervals
- Circuit outage and faulted section identification and isolation switching
- Substation and feeder VAR management
- Substation and feeder voltage management
- Substation and feeder integrated Volt/VAR Management
- Substation and feeder overload management with Dynamic Voltage Control (DVC) and Conservation Voltage Reduction (CVR)
- Distributed energy resource monitoring and management
- Substation and feeder overload management with Distributed Energy Resources
- Digital fault recording on breaker relays

The project team also expects to demonstrate time-synchronized voltage and current from strategic points on the circuits, which will improve the accuracy of capacity planning models and will enable better load balancing and improved decision-making for capacity additions.

1.2.1.1.8 SmartGeneration

The primary objective of the SmartGeneration subproject is two-fold. The program will develop and demonstrate a next-generation, end-to-end Distributed Energy Resource Management (DERM) system that can provide balancing of renewable and variable distributed energy resources (DER) with controllable demand response (DR) as it becomes integrated in the utility grid, coordination with market systems, and provision of potential future pricing signals.

The project team expects to demonstrate a number of capabilities including:

- The ability to manage and control diverse DERs (e.g. DVC, DG, storage, etc.)
- The ability to manage and control various DR programs effectively
- The ability to manage price-based and voluntary programs with market-based and dynamic tariffs similar to those described under SmartEnd-Use
- Interoperability with the DMS to monitor distribution grid conditions and leverage DR and DERs to manage distribution grid congestion

The SmartGeneration subproject will also implement DR/DER resources and DR programs sufficient in quantity and diversity to support the DERM development and demonstration. This subproject will include:

- Installation of a variety of rooftop solar systems on a mix of residential and commercial buildings, including one larger scale installation (100 kW)
- Installation of a 1MW grid-connected battery
- Implementation of an AMI-based direct load control (DLC) DR program with installation of up to 1600 stand-alone residential PCTs
- Implementation of a home energy management program with installation of up to 400 Home Area Networks that include a PCT, 120V outlet disconnects, and 240V (water heater, pool pump, etc.) disconnects
- Implementation of DR-enabled publicly accessible plug-in electric vehicle charging stations to demonstrate smart charging strategies

By achieving these objectives, KCP&L expects to demonstrate advanced capabilities in demand side resource management, including the ability to leverage those resources for operational efficiencies, reduction of environmental impact, and to support wholesale market operations.

In addition to the primary objective, KCP&L expects to evaluate the feasibility to offset fossil-based generation with renewable sources as well as the potential for flexible, alternative business ownership models.

1.2.1.1.9 SmartGrid Functions

The DOE has identified a series of Smart Grid Functions [2] that capture the characteristics or capabilities of a smart grid. Each of the KCP&L SGDP subprojects will implement a variety of SmartGrid assets and technologies that enable one or more of these Smart Grid Functions. Table 1-1 below, identifies which subproject will directly implement or support the Smart Grid Functions that will be implemented by the project.

Table 1-1: Smart Grid Functions by KCP&L Demonstration Subproject

Smart Grid Functions D = Direct S = Support		Demonstration Subproject				
		Smart Metering	Smart End-Use	Smart Substation	Smart Distribution	Smart Generation
Smart Grid Functions	Fault Current Limiting					
	Wide Area Monitoring, Visualization, and Control					
	Dynamic Capability Rating					
	Power Flow Control					
	Adaptive Protection					
	Automated Feeder Switching			S	**D**	
	Automated Islanding and Reconnection			S	S	**D**
	Automated Voltage and VAR control	S		S	**D**	
	Diagnosis and Notification of Equipment Condition			**D**	**D**	
	Enhanced Fault Protection					
	Real-Time Load Measurement and Management	**D**	S			**D**
	Real-Time Load Transfer	S		S	**D**	
	Customer Electricity Use Optimization	**D**	**D**			
	Distributed Production of Electricity					**D**
	Storing Electricity for Later Use					**D**

1.2.1.1.10 Smart Grid Benefits

The KCP&L SGDP components, technologies, and smart grid functions to be demonstrated were chosen because they have the possibility of providing extensive system benefits, individually, and collectively, they offer an even more effective means for achieving the project objectives. For each of the project components, KCP&L has identified the DOE identified SmartGrid benefits [2] [3] that are anticipated to be observed, quantified, or calculated during the course of the project are summarized in Table 1-2 below.

Table 1-2: Smart Grid Benefits Realized by KCP&L Demonstration Subproject

Smart Grid Benefits D = Direct Benefit I = Indirect Benefit			Demonstration Subproject				
			Smart Metering	Smart End-Use	Smart Substation	Smart Distribution	Smart Generation
Economic	Market Revenue	Arbitrage Revenue*					
		Capacity Revenue*					
		Ancillary Services Revenue*					
	Improved Asset Utilization	Optimized Generator Operation					
		Deferred Gen. Capacity Investments	I	D			D
		Reduced Ancillary Service Cost					
		Reduced Congestion Cost					
	T&D Capital Savings	Deferred Trans. Capacity Investment					
		Deferred Dist. Capacity Investments		D		D	D
		Reduced Equipment Failures			D	D	
	T&D O&M Savings	Reduced Dist. Equip. O&M Cost					
		Reduced Dist. Operations Cost				D	
		Reduced Meter Reading Cost	D				
	Reduced Theft	Reduced Electricity Theft	D				
	Energy Efficiency	Reduced Electricity Losses	I	I		D	D
	Electricity Cost	Reduced Electricity Cost		D			D
Reliability	Power Interruptions	Reduced Sustained Outages			D	D	D
		Reduced Major Outages	D		D	D	
		Reduced Restoration Cost	D		D	D	
	Power Quality	Reduced Momentary Outages					
		Reduced Sags and Swells					
Environ-mental	Air Emissions	Reduced carbon dioxide Emissions		I		I	D
		Reduced Emissions		I		I	D
Security	Energy Security	Reduced Oil Usage	D		I	D	
		Reduced Wide-scale Blackouts					

*These benefits are only applicable to energy storage demonstrations.

1.2.2 Introduction to Kansas City Power & Light Company

The mission of KCP&L, as a leading and trusted energy partner, is to provide safe, reliable power and customer-focused energy solutions that create stakeholder value through operational excellence, innovation, and a diverse, engaged workforce. Our higher purpose is improving life in the communities that KCP&L serves.

Great Plains Energy (GPE), a Missouri corporation incorporated in 2001 and headquartered in Kansas City, Missouri, is the holding company for two vertically integrated electric utilities - KCP&L and KCP&L Greater Missouri Operations Company (KCP&L-GMO). Both utilities operate under the brand name KCP&L. KCP&L's service territory encompasses all or portions of 47 counties over approximately 18,000 square miles in western Missouri and eastern Kansas.

1.2.2.1.1 KCP&L Utility Operations

Operating from its headquarters in Kansas City, Missouri, KCP&L has evolved into a full-service energy provider and resource. The company was founded in 1882 and has become one of the Midwest's most affordable energy suppliers because of our leadership in efficient power production and distribution through advanced fuel procurement, power plant technology, and distribution technology.

Our utilities serve over 820,000 customers with approximately 722,000 residential, 96,000 commercial, and 2,800 industrial and bulk power customers. Our utilities, located in Missouri and Kansas, have a combined generation capacity of over 6,100 MW, 3,000 miles of transmission lines, approximately 17,000 miles of overhead distribution lines, and over 7,000 miles of underground distribution lines. Detailed statistics of KCP&L's service territory are shown in Table 1-3.

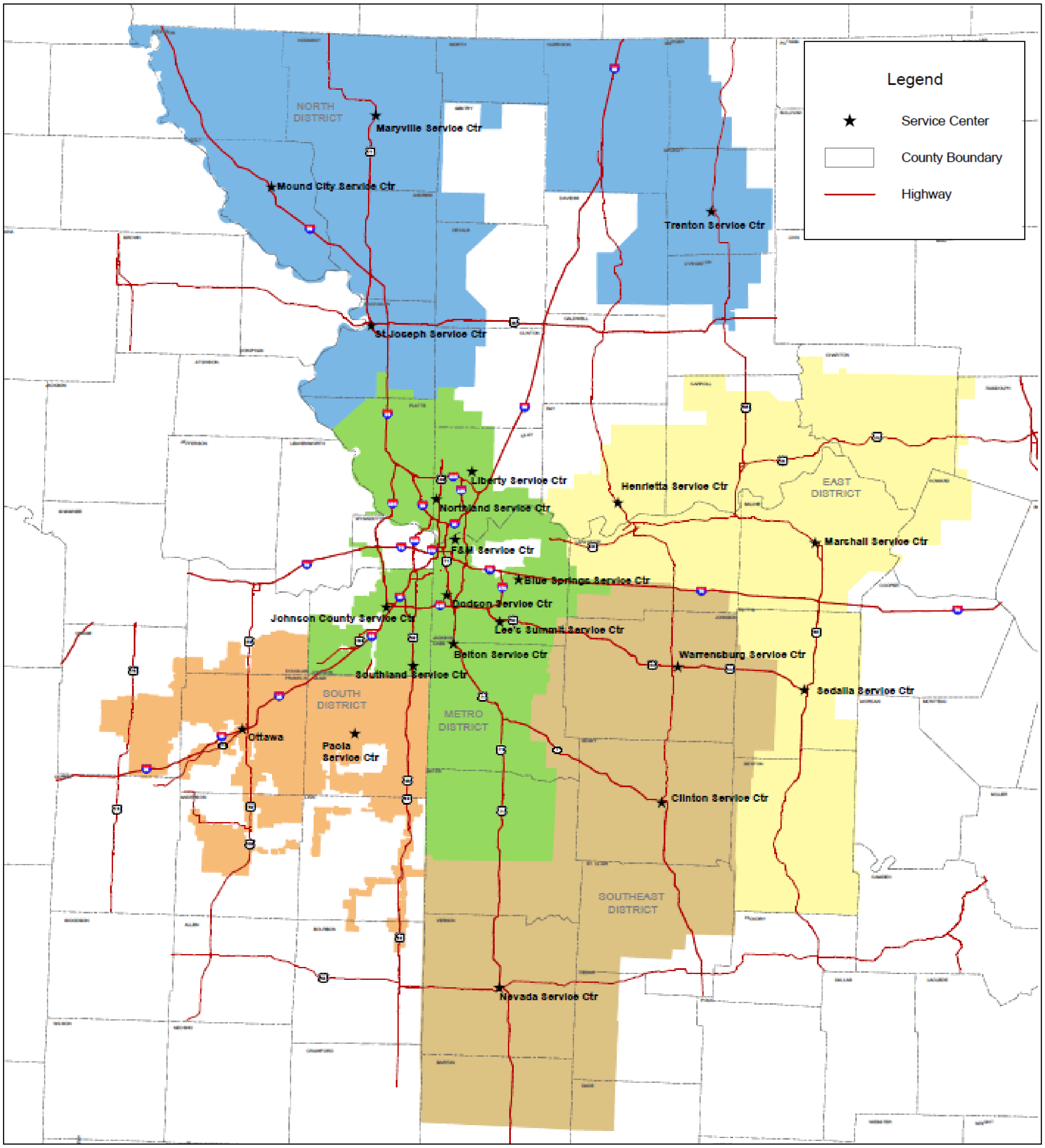
Table 1-3: KCP&L's Service Territory Statistics

KCP&L's Service Territory			
	GPE	**KCP&L**	**KCP&L - GMO**
Total number of customers:			
Residential	723,752	450,359	273,393
Commercial	95,801	57,725	38,076
Industrial & Municipal	2,753	2,393	360
Peak load:			
Summer	5,253 MW	3,448 MW	1,878 MW
Winter	4,115 MW	2,670 MW	1,568 MW
Total MWh sales:			
Residential	8,647,450	5,202,904	3,444,546
Commercial	10,636,691	7,506,463	3,130,228
Industrial	3,142,761	1,884,401	1,258,360
Bulk Power	5,492,710	5,280,312	212,398
Distribution Assets:			
Total number of substations	316	91	225
Total number of distribution feeders	1382	767	615
Total miles of overhead distribution line	17,000 mi.	11,768 mi.	5,232 mi.
Total miles of underground distribution lines	7,000 mi.	4,502 mi.	2,498 mi.
Total miles of transmission lines	3,000 mi.	1,765 mi.	1,235 mi.

1.2.2.1.2 Service Territory

As shown in Figure 1-1, KCP&L services customers in 47 northwestern Missouri and eastern Kansas counties - a service territory of approximately 18,000 square miles (www.kcpl.com).

Figure 1-1: KCP&L Service Territory Map



1.2.2.1.3 Regulation and Oversight

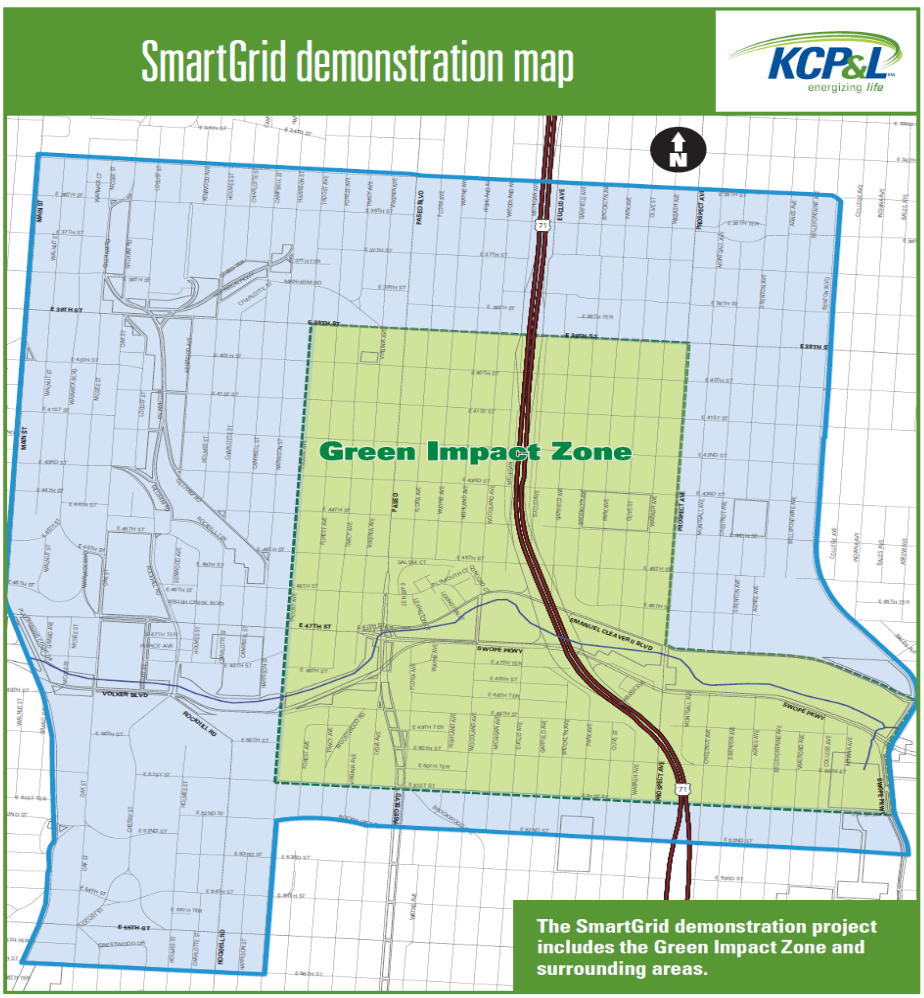
Both utilities are regulated by the Missouri Public Service Commission (MPSC). Kansas City Power & Light is regulated also by the Kansas Corporation Commission (KCC) with respect to retail rates, certain accounting matters, standards of service, and, in certain cases, the issuance of securities, certification of facilities, and service territories.

The utilities are also subject to regulation and oversight by the Federal Energy Regulatory Commission (FERC), North American Electric Reliability Corporation (NERC), and Southwest Power Pool, Inc. (SPP). Kansas City Power & Light has a 47% ownership interest in the Wolf Creek Generating Station (Wolf Creek), which is subject to regulation by the Nuclear Regulatory Commission (NRC), with respect to licensing, operations, and safety-related requirements.

1.2.3 Project Location

The SGDP will deploy smart grid technologies on the KCP&L distribution system to the entire Green Impact Zone plus surrounding areas as shown in Figure 1-2. The total SGDP area is approximately five square miles (www.kcplsmartgrid.com).

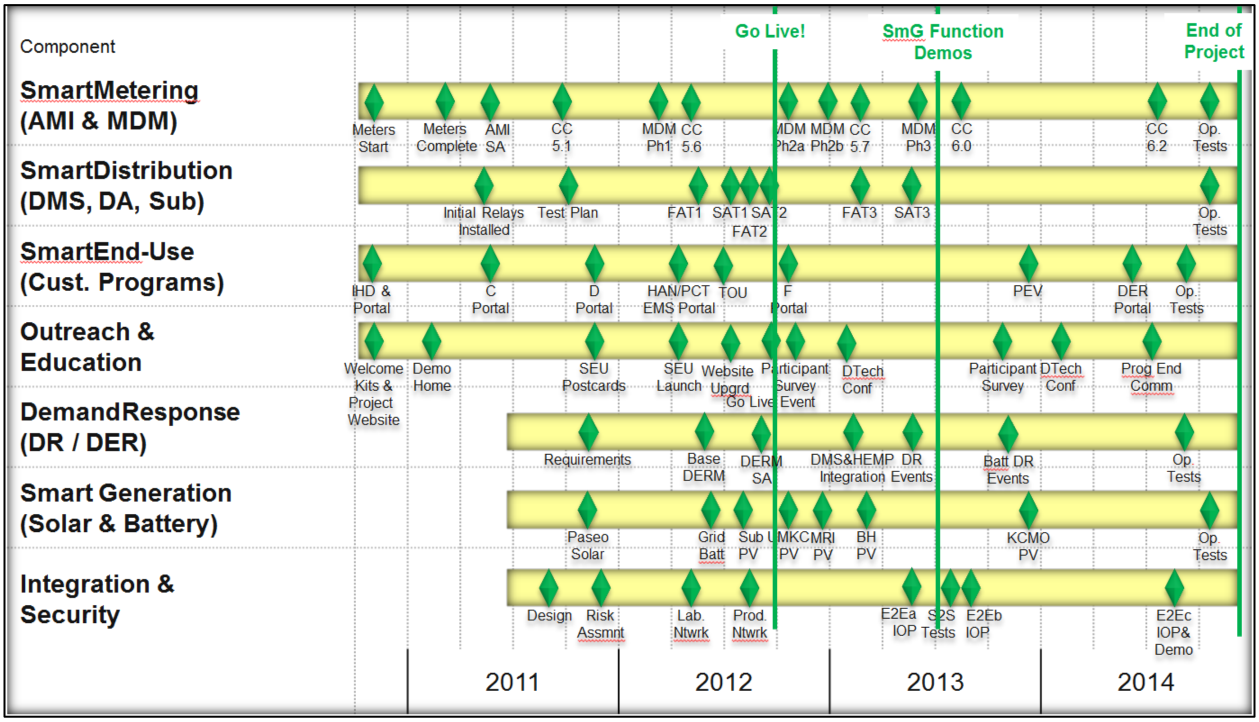
Figure 1-2: KCP&L Green Impact Zone SmartGrid Demonstration Map



1.2.4 Project Timeline

This section includes a condensed schedule of the KCP&L SGDP. The schedule shown in Figure 1-3 includes main subcomponents of the project and shows their relative start and completion dates. Interdependencies between tasks are not shown on this schedule; however, they were managed in a Microsoft Project file used by the project team.

Figure 1-3: Project Timeline



1.2.5 Project Major Milestones

The master project schedule is aligned with the WBS; key project milestones are listed in Table 1-4. During project performance, KCP&L will report the Milestone Status as part of the required monthly Progress Report as prescribed under the Reporting Requirements Checklist. The Milestone Status will present actual performance in comparison with the Milestone Log, and include:

- the actual status and progress of the project;
- specific progress made toward achieving the project's milestones; and
- any proposed changes to the project's schedule required to complete milestones.

The shaded milestones have been published by the DOE as external project milestones.

Table 1-4: Major Project Milestones

Task	Milestone	Planned Completion Date	Revised Completion Date	Actual Completion Date
1	Revised PMP to DOE for Review	10/29/2010		10/29/2010
2	NEPA Compliance obtained	10/28/2010		10/28/2010
3.2	Develop Initial Cyber Security Plan	10/29/2010		10/29/2010
4.4	Develop Benefits & Metrics Reporting Plan (v1.0 Submitted)	12/30/2010		12/30/2010
5.7.1	First Interim Technology Performance Report	12/31/2012		12/31/2012
5.7.2	Second Interim Technology Performance Report	12/31/2013		12/31/2013
5.7.3	Third Interim Technology Performance Report	12/31/2014		12/31/2014
6	Public Outreach and Education	06/30/2014		04/30/2014
	SmartGrid Demonstration Home Grand Opening			04/30/2011
	Innovation Park Grand Opening			10/12/2012
8.4	SmartMetering Deployment	03/18/2011		03/18/2011
8.5	SmartMetering System Acceptance	05/13/2011		05/13/2011
9.4	Collect Consumer 15 min Interval Usage Data	01/03/2012		03/31/2012
10.4	SmartSubstation Protection Network Factory Config. & FAT	12/21/2011		05/04/2012
10.7	SmartSubstation Automation Network Factory Config. & FAT	06/14/2012	08/30/2012	08/30/2012
10.10	Commission SmartSubstation (ready for day-to-day operations)	09/30/2012		09/30/2012
11.4	MDM Phase 1 – Implementation	12/30/2011		03/24/2012
12.10	DMS Factory Configuration and FAT	12/21/2011	08/30/2012	08/30/2012
12.14	Commission DMS System (ready for day-to-day operations)	07/10/2012	09/30/2012	09/30/2012
13.2	Design, Construct, & Test SmartDistribution IP FAN	09/30/2012		09/21/2012
13.6	Commission SmartGrid First Responder Subsystem	12/21/2011	08/31/2013	08/27/2013
14	Deploy SmartEnd-Use Implementation (14.2-4 & 14.6-9)	12/31/2012		06/30/2012
14.3	Implement Home Energy WEB Portal	12/08/2010		10/20/2010
14.4	Implement Home Energy EMS Web Portal	07/06/2011	07/31/2012	06/28/2012
14.5	Implement Home Energy DER Portal	07/06/2011	06/30/2014	07/11/2014
14.6.5	Launch In-Home Display	10/27/2010		10/27/2010
14.7	Demonstration Home Grand Opening	07/13/2011		04/30/2011
14.8	Launch EMS HAN Devices	04/30/2012		04/30/2012
14.9	Launch TOU Tariff	04/30/2012		05/22/2012
15	SmartGeneration Implementation	06/30/2014		06/10/2014
15.1	Deploy Grid Connected Rooftop Solar	01/11/2012	09/30/2013	12/15/2013
15.2	Deploy DR AMI Thermostats (Available to Customers)			04/30/2012
15.5.16	Commission BESS	07/27/2012		06/28/2012
16	Smart DER/DR Management System Implementation	07/03/2014		02/28/2014
16.5	Implement & Unit Test DR Management Sub-system	06/30/2012	07/30/2012	07/27/2012
17.2	Conduct System-System Integration Testing	06/08/2012	07/31/2013	07/31/2013
17.4	Field Demo Integrated SmartGrid Functionality	12/31/2012	06/30/2013	06/28/2013
18.1	Operate System According to Program Plan & Procedures	10/01/2012		10/01/2012
18	Operate Integrated Solution (complete)	10/31/2014		10/31/2014
20.1.4	Submit Draft Report to DOE for Review	12/31/2014	03/31/2015	03/31/2015

1.3 SmartGrid Demonstration Project Participants

KCP&L has developed a technical solution model working with a set of best-in-breed vendor participants. The vision for the SGDP is to bring these technical implementation vendors and their capabilities together to develop leading edge, scalable SmartGrid solutions. In selecting participating vendors, KCP&L focused on companies with which it has established relationships, who are leading companies in their respective SmartGrid area, and who share the SmartGrid vision set forth in the SGDP.

To further the cause of SmartGrid technology development, partners that have agreed to contribute in-kind to the effort have been classified and treated as project partners. In addition to these project partners, KCP&L will work closely with selected vendors to ensure a successful deployment of the SGDP. These strategic partners and vendors are shown in Figure 1-4 and described below.

Figure 1-4: Selected Project Partners

1.3.1 Project Partners

In addition to providing equipment, technical expertise, and in-kind financial support, the project vendor partners will provide leadership on the technical and process aspects of the project, including the selection, implementation, and review of emerging technologies, and ensure that the project's vision is brought to bear through the collaboration of the project's partners and stakeholders.

1.3.1.1.1 Electric Power Research Institute (EPRI)

EPRI conducts research and development relating to the generation, delivery, and use of electricity for the benefit of the public. EPRI will provide technical expertise and advice on defined portions of the project. In addition, they are a member of the five-year EPRI Smart Grid Demonstration Initiative, which is focused on smart grid projects that integrate distributed energy resources (www.smartgrid.epri.com). One of the main objectives of this initiative is to identify approaches for interoperability and integration that can be used on a system-wide scale to help standardize the use of DER as part of overall system operations and control. As part of this Initiative, EPRI will support this project in several areas including, but not limited to, cost-benefit analysis efforts, use case documentation per the IntelliGrid^{SM} methodology, data analysis and benefits estimation, CO_2 impact assessment, and technology transfer.

1.3.1.1.2 eMeter/Siemens

eMeter's EnergyIP MDM solution is the industry's leading platform for real-time smart grid data management. Purpose-built for mass market deployment in heterogeneous and evolving technology environments, EnergyIP brings scalability, adaptability, and flexibility to the utility enterprise. eMeter/Siemens will implement the EnergyIP product to provide an enterprise level repository of meter and metering data and support the provision of validated, estimated, and edited (VEE'd) AMI data.

1.3.1.1.3 Exergonix

Exergonix will leverage existing lithium polymer battery technology development and manufacturing expertise to develop and deploy a grid-scale energy storage system to supply peak-shaving, demand-management, and restoration capabilities to the KCP&L grid. The installation will function as part of a larger DERM system, controlled remotely and programmed to function automatically in conjunction with other SmartGrid components.

1.3.1.1.4 Intergraph

Intergraph is a strategic partner of Siemens Inc., together leading the industry with a number of active smart grid projects. Through the partnership, Intergraph and Siemens provide a Smart Grid Operations Command-and-Control Center that integrates an advanced DMS with SCADA functionality, outage management, mobile workforce management, and electric and communications infrastructure management.

Intergraph has also partnered with eMeter to integrate MDM functionality with their Command-and-Control Center platform. The integration will provide grid operators with consolidated end-to-end network visibility and management capabilities to provide utilities with the full operational benefits of their AMI and smart meter deployments for use in outage detection and response. KCP&L will be implementing Intergraph's Smart Grid Operations Command-and-Control Center integrated with Siemens DMS and eMeter's MDM.

1.3.1.1.5 Landis+Gyr

Landis+Gyr ranks as the worldwide leader in electricity metering with a preeminent position in advanced or "smart metering" systems. In 1994, KCP&L partnered with L+G (then Cellnet) to develop and deploy the first production AMR system in use by a utility. Today, L+G offers the broadest portfolio of products and services in the electricity metering industry including integrated AMR/AMI solutions, communication systems and software, meters, meter data management services, and financing. KCP&L is again partnering with L+G to deploy a state-of-the-art Gridstream technology, AMI system and RF mesh AMI field area network.

1.3.1.1.6 OATI

Open Access Technology International (OATI) Inc. has been serving the energy industry since 1995 and has had steady growth since its inception. As a sub-recipient, OATI will deploy the Distributed Energy Resource Management system component of the SGDP through implementation of its webSmartEnergy application. The webSmartEnergy suites of applications are modular solutions to address the requirements for the emerging SmartGrid. OATI webSmartEnergy products include software and services for Demand Response and Distributed Energy Resources Management, Renewable Management, and Asset Management.

1.3.1.1.7 Siemens

Siemens is a world-wide provider of products and services whose experience spans the entire energy network, including generation, transmission, distribution, and the market. They focus on reliable, efficient, and practical innovation and implementation in each segment. As a sub-recipient, they will focus on providing the distribution network First Responder functions and the integration of the DMS with SmartSubstation controllers and Distribution SCADA, as well as integration with the GIS, AMI, MDM, and DERM systems.

Siemens plays a dual partner role in that they are both a sub-recipient and a vendor. As a vendor, Siemens will provide the SmartSubstation automation controllers, Distribution SCADA, DMS, and a variety of substation and field grid devices and IEDs. Siemens also teamed up with eMeter (and later purchased eMeter) to provide the MDM.

1.3.1.1.8 Tendril

Tendril offers solutions to aid customers in understanding, reducing, and managing energy consumption. Tendril will provide a residential Home Energy Management Portal and Home Area Network platform which will provide energy consumers and utilities with an intelligent network of distributed energy resource management tools that will enable consumer and utility control through a single Web-based interface.

1.3.2 Consultants

1.3.2.1.1 Bridge Strategy Group

Bridge Strategy Group is an elite general management consulting firm used by KCP&L on numerous occasions on key strategic assignments. Bridge was retained to temporarily perform the Director of SmartGrid project functions and provide project level consulting services during the initiation phase in the form of guidance, expertise, and project support to the SmartGrid PMO.

1.3.2.1.2 Burns & McDonnell Engineering Company

Founded in 1898, Burns & McDonnell is a 100 percent employee-owned, full-service engineering, architecture, construction, environmental and consulting solutions firm with over 4,000 professionals in more than 30 offices. Burns & McDonnell will provide assistance to KCP&L in the form of skilled staff to augment the project team.

1.3.2.1.3 IBM

IBM Global Services is the world's largest information technology services provider with professionals servicing customers in 160 countries. They are at the forefront of developing, integrating, and implementing smart grid systems. IBM will provide assistance to KCP&L in the development of the project Interoperability and Cyber Security Plan.

1.3.2.1.4 The Structure Group
The Structure Group is an energy and utility consulting firm specializing in SmartGrid, energy management, risk management, and competitive market solutions and will provide assistance to KCP&L in the form of skilled staff to augment the project team, particularly in the role of IT integration.

1.3.3 Contractors

1.3.3.1.1 AOS
Alexander Open Systems (AOS) specializes in consulting, designing, implementing, and supporting Local, Wide Area, and Wireless Networking, Communication and Collaboration, Data Center, and Physical and Data Security. AOS will provide assistance to KCP&L in the form of skilled staff to augment the IT project team.

1.3.3.1.2 Corix Utilities
KCP&L currently contracts with Corix Utilities to provide manual meter reading services for the non-AMR service territory. Corix has performed over 3,000,000 meter changes, AMR/AMI device installations, and retrofits for gas, water, and electric utilities since 1995, helping utilities make a smooth transition from traditional meter reading to automation. Corix has been retained to perform a pre-deployment audit of all electric meters in the SGDP area.

1.3.3.1.3 Global Prairie
Global Prairie is an integrated communications and brand management company. Global Prairie will be providing education and outreach enrollment and soliciting volunteers to assist in these efforts.

1.3.3.1.4 MARC
The Mid-America Regional Council (MARC) provides administrative staff and services for the Green Impact Zone. The Green Impact Zone initiative is an effort to concentrate resources — with funding, coordination, and public and private partnerships — in one specific area to demonstrate that a targeted effort can literally transform a community. Plans are underway to make the Green Impact Zone a model for energy efficiency. Neighborhood leaders, the coordinating council, local utilities, and other strategic partners intend to develop and implement a highly coordinated initiative to reduce energy and water usage within the zone — and, in the process, reduce utility bills for residents. The initiative will include individual property strategies as well as neighborhood-wide strategies, such as installation of a smart grid and the expansion of solar and other renewable energy sources within the zone.

1.3.3.1.5 Metropolitan Energy Center
The Metropolitan Energy Center's mission, when it was founded, was to assist people in the Kansas City region to manage and control their energy use. This nonprofit organization has evolved to become a catalyst for community partnerships focused on energy efficiency, environmental stewardship and economic improvement. KCP&L has partnered with MEC to integrate the SmartGrid Demonstration Home in their "Project Living Proof" demonstration. More information may be found at http://www.kcenergy.org/community.htm.

1.3.3.1.6 NextSource
NextSource is a global labor resource provider. NextSource will provide assistance to KCP&L in the form of on-site personnel in a variety of roles.

1.3.3.1.7 QTI, Inc.
QTI, Inc. is a corporation that provides general construction services along with fiber optic network build outs, underground power distribution, and warehouse distribution. QTI, Inc. has been selected to manage the AMI meter deployment with a locally hired and trained workforce.

1.3.4 Vendors

1.3.4.1.1 Cisco
A Cisco® Smart Grid network is a holistic, cross-technology solution that enables utilities and other organizations in the energy industry to build secure, standards-based IP networks to efficiently meet the demands of energy generation, distribution, storage, and consumption. KCP&L will extend the existing Cisco based network to support the SGDP by implementing a new Cisco Smart Grid network as the foundation of the SmartSubstation.

1.3.4.1.2 Milbank
Milbank, headquartered in Kansas City, is an industry leader in the manufacture of electrical meter sockets and has been servicing the electric utility and wholesale distribution industries for over 75 years with innovative, quality engineered products. Milbank will be providing retrofit A-base meter enclosure covers to accommodate the larger physical dimensions of the AMI meters.

1.3.4.1.3 Oracle
Oracle is the leader in the worldwide relational database management systems (RDBMS) software market and holds more market share than its four closest competitors combined. The Oracle RDBMS is an integral foundation for many of the SmartGrid demonstration system components to be implemented.

1.3.4.1.4 Ruggedcom
Ruggedcom designs and manufactures rugged communications equipment for harsh environments such as substations and other outdoor applications. KCP&L will use Ruggedcom network components to implement half of the redundant SmartSubstation IP based protection network.

1.3.4.1.5 Schweitzer Engineering Laboratories (SEL)
SEL designs, manufactures, and supports a complete line of products and services for the protection, monitoring, control, automation, and metering of electric power systems. KCP&L will replace existing electromechanical relays with new SEL feeder relays in transforming the Midtown Substation to a next generation SmartSubstation.

1.3.4.1.6 SISCO
The SISCO ICCP product is being used to integrate the Intergraph and Siemens products. The ICCP-TASE.2 (IEC60870-6) is the internationally accepted standard for the exchange of real-time data in energy utilities for control center integration.

1.3.4.1.7 Sunverge
Sunverge provided the premise energy storage systems, an intelligent distributed energy storage system that captures solar power and delivers it when needed most. It combines batteries, power electronics, and multiple energy inputs controlled by software running in the cloud.

1.3.4.1.8 Tropos
Tropos provides wireless communications networks for utilities to build and control the smart grid. Tropos will provide the wireless, IP-based mesh network for distribution automation.

1.4 DEMONSTRATION SYSTEMS & TECHNOLOGIES

The KCP&L SGDP will demonstrate the value of integrating smart grid technology, communications and control systems to manage the distribution system in cooperation with distributed energy resources within a utility's service territory. In particular, the project team is targeting distributed, edge-of-grid, resources using a comprehensive next generation smart grid infrastructure to integrate and manage the distributed grid assets. Not only will the distributed energy resources be aggregated, visible, and available to the energy traders and bulk grid operators, they will also be available to the DMS and distribution operators as a tool to solve local congestion or power quality issues. Ultimately, individual or circuit aggregated resources can be initiated automatically by the DCADA as one of its First Responder functions.

1.4.1 Demonstration Systems Overview

The KCP&L SGDP focuses on the Company's Midtown Substation and multiple distribution circuits serving approximately 14,000 customers across 3.75 square miles with total demand of up to approximately 69.5 MVA. The scope of work, illustrated in Figure 1-5, touches every functional area of the electricity distribution network.

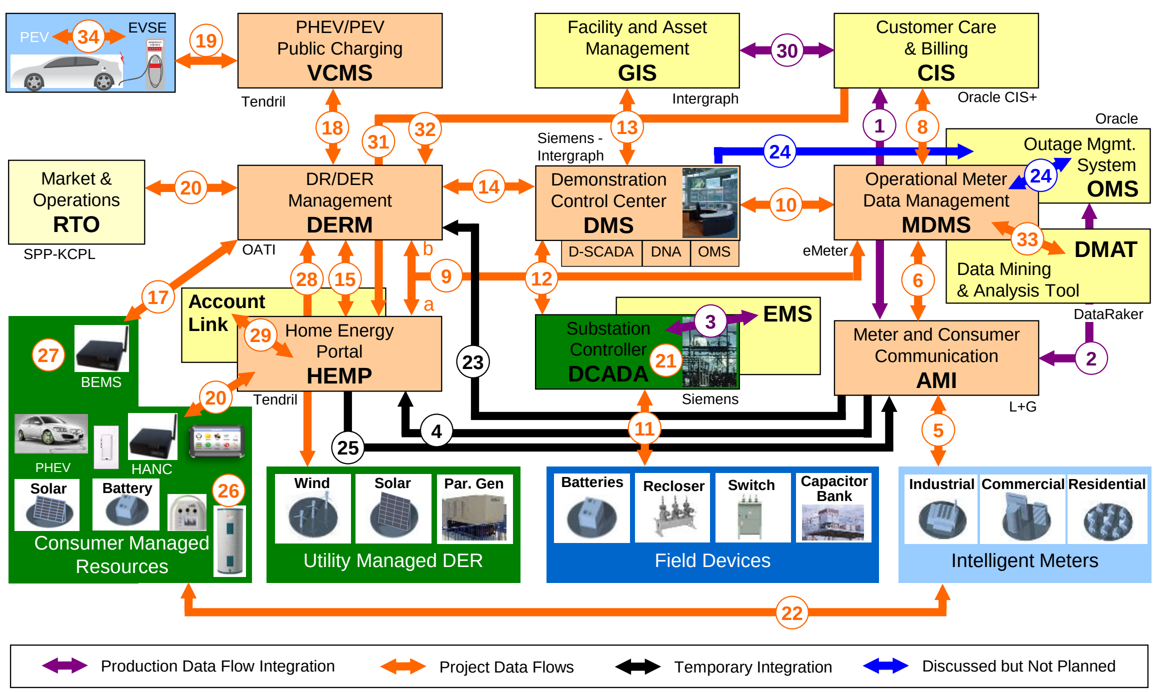
Figure 1-5: KCP&L Demonstration, a True End-to-End SmartGrid

The SmartGrid pilot infrastructure includes a distribution grid control system that consists of five major components as shown in Figure 1-6 below. The grid control infrastructure is a "stand-alone" system for the SGDP, but it is used to control the grid as part of normal day-to-day operations within the SGDP area.

The pilot infrastructure components include:

- Distribution Management System. This provides all the necessary systems and applications for the KCP&L Control Center Operators to manage the distribution network reliability, quality of supply, coordinate with substation controllers and field automation, and enhance efficiency of the operations, crew, and maintenance staff.
- Distributed Control and Data Acquisition. This DCADA includes the SmartSubstation control functions and the automation of reclosers, switches, and capacitor banks to support communication with Smart-Substation™ Controllers for automated feeder reconfiguration.
- Advanced Metering Infrastructure and Meter Data Management. This supports two-way communication with electronic meters for consumer billing information, verification of electrical service status, and remote service on-off capabilities.
- Distributed Energy Resource Management. This provides balancing of renewable and variable energy sources with controllable demand as it becomes integrated in the utility grid, coordination with market systems, and provision of pricing signals to consumers.
- Home and Vehicle Energy Management. This enables customers to make informed consumption decisions and allows consumer managed resources to participate in proactive utility grid management programs.

Figure 1-6: KCP&L Demonstration, T&D Control Systems Infrastructure



As depicted in Figure 1-6, there are four (4) integration points with existing systems; GIS, CIS, OMS, and EMS/SCADA.

- GIS – will continue to be the source of facility and network connectivity information.
- CIS – will continue to be the source of customer information and will continue to provide billing functions for customers on existing rate structures.
- OMS – will continue to be the production system for analysis of customer outage information for manual dispatch. The DMS will process outage calls for automated restoration and demonstration purposes.

- EMS/SCADA - will continue to have control authority over the distribution functions for which it currently controls, primarily distribution feeder breakers. DMS will have control authority over all new control functions.

This pilot infrastructure creates the next-generation grid monitoring and control platform that is being used to manage the KCP&L Green Impact Zone SmartGrid Demonstration grid for project duration.

The DMS and DCADA provide the operational backbone of the system supporting significant levels of automation on the feeders, complex and automated feeder reconfiguration decisions, and tightly integrated supervision with the Control Centers. The DMS serves as the primary point of integration for the grid facilities, electrical system load, and real-time substation and feeder information. It includes Distribution Supervisory Control and Data Acquisition (D-SCADA), Distribution Network Analysis (DNA), Outage Management (OMS) and integration with KCP&L's existing Mobile Work Force Management system, Geographic Information System (GIS), and other supporting systems.

The Smart-Substation™ controller establishes an intelligent substation IT infrastructure with the ability to make feeder and substation reconfiguration decisions, control field equipment, verify operations, track local grid capacity, and coordinate with the DMS. This "proactive" management of the distribution grid is a necessary step in preparing for the integration of significant levels of renewable and variable energy resources, controllable demand, and demand response. With the addition of distributed energy resources, the DMS and Smart-Substation™ become essential to managing Volt/VAR conditions, adaptively modifying protection equipment settings, and managing crew safety.

The AMI and MDM provide access, collection, and management of meter asset information and the consumer metering information for billing, consumer awareness and consumer participation in demand management and response programs or the market. They will be deployed to all customers in the KCP&L Green Impact Zone SGDP area, including residential, commercial and industrial consumers. They will collect the customers' 15 minute interval consumption data required to support many of the SmartGrid analyses to be performed and the experimental TOU rates and other EE/DR incentives to be evaluated. Additionally, the MDM will manage the flow of events and other data flows between the legacy CIS and OMS and the demonstration DMS/OMS and DERM systems and provide an avenue for integration with selected HAN management systems.

The DERM system provides all the necessary functions to balance distributed energy resources with available dispatchable ("controllable") demand to make most efficient use of existing energy options while optimizing economic value for consumers in the market. It aggregates distributed energy resources and controllable load groups for dispatch and market participation with group and, potentially, demographic leverage. It assesses balancing within a defined future time period (i.e. 5 minutes) and issues commands to participating resources to adjust their output and/or demand where appropriate. Excess resources can be bid into the market. The system tracks aggregate and individual resource commitments and settles accounts. It uses available load models and network conditions from the DMS as constraints to ensure reliable network operation, request network control changes and verify resource participation. It accepts requests from the DMS to suspend dispatch of energy resources in areas where operational safety conditions are at risk. It will use consumption information from the AMI and MDM systems to verify demand management/response participation. It will track, retain, and report all information necessary to quantify resource and related economic participation.

All these systems assume an underlying standards-based infrastructure of communications, field automation, and end-to-end cyber-security. The demonstration systems are fully integrated using the standards defined by the NIST Smart Grid Interoperability Framework, where applicable, and interface with existing production systems at KCP&L at clearly defined and controlled integration points to maintain the security and integrity of KCP&L enterprise systems. As a whole, the program is verifying a full range of NIST and other standard modeling and information exchange protocols necessary to implement a functional, cost-effective, secure intelligent grid. The project has helped define, validate, and verify the necessary parameters and potential solution adjustments for KCP&L, and the industry, to plan and implement a system wide roll-out of the successful smart grid technologies and processes.

Several fundamental aspects of next generation smart grid T&D Infrastructure are being demonstrated and verified in this project, including:

- State-of-the-art multi-transformer, multi-bus distribution substation upgrade
- SmartSubstation with IEC61850 communication protocols over a secure IP Ethernet substation LAN
- Highly-integrated, distributed hierarchal control solution between a centralized DERM system, DMS/SCADA system, a distributed DCADA controller within the SmartSubstation, and individual IED field controls
- Automated First Responder distributed decision making through intelligent substation controllers and enabled feeder devices
- Dynamic equipment ratings based on field conditions
- Integrated supervision of automation and filtering of field information to improve distribution operations situational awareness
- Integration of distributed and renewable energy resources and controllable demand
- Availability of customer demand response, price signals, and market participation
- Two-way accessibility of the customer meter, availability of current energy usage information, and customer participation in energy programs
- A comprehensive SmartGrid communications infrastructure
- End-to-end cyber security provisions

The following subsections describe the various subprojects of the SGDP.

1.4.2 SmartMetering

The SmartMetering subproject deployed a state-of-the-art integrated AMI and MDM. AMI deployment consisted of replacing all customer meters within the SGDP area (approximately 14,000 meters) with communicating SmartMeters and installing an accompanying wireless two-way communication network to enable real-time communications between the meters and the MDM. The MDM stores and manages all meter data reported by the SmartMeters and is integrated with KCP&L's other systems including the CIS, DMS, OMS, and the DERM.

The SmartMeters lower operating costs, increase the frequency of meter reads, increase the accuracy of meter reads, and facilitate utility-controlled demand response messaging. Customer satisfaction will be improved through remote service connect/disconnect, on-demand meter reading, and increased customer access to usage information. Furthermore, overall system reliability has been increased through enhanced outage/restoration notification.

1.4.2.1 Advanced Metering Infrastructure

1.4.2.1.1 AMI Overview

The Landis+Gyr Gridstream SmartGrid communication system and SmartMeters provide the capability for AMI and Home Area Networks (HAN) via a common two-way communication infrastructure. The system supports the acquisition of load profile, time-of-use and demand meter data, and meter and site diagnostic information from the electric meters that perform these measurements. Using meters equipped with these capabilities, the system also supports "under-glass" remote physical disconnect and HAN communication via the ZigBee-standard SEP. SmartMeters also support outage and restoration reporting and real-time on-demand reads.

1.4.2.1.2 AMI Characteristics

The AMI is composed of two main components: Command Center – the AMI Head-End System (AHE) and the Gridstream Wireless Field Area Network (FAN). The AHE is the software and hardware that allows the utility to interact with the AMI and integrate the AMI with other systems within the utility. The FAN is the hardware (collectors, routers, and meters) that enables the utility to receive meter data and send commands to meters.

1.4.2.1.2.1 Command Center – The AMI Head-End System

The AHE is the advanced metering software and hardware platform that enables data reporting and system control between itself and the FAN. The scalable system enables KCP&L to remotely program meters, manage remote connects/disconnects, analyze critical peak usage, view load control indices, and perform other critical, day-to-day functional operations. The AHE simultaneously manages the meter data collected from all SmartMeters within the SGDP area, validating each data element, and integrates the data with the MDM. The AHE is compliant with the MultiSpeak, CIM, and IEC 61968 standards. The AHE utilizes Web Service APIs to interface with other systems and can deliver specific scheduled data extracts to these systems.

1.4.2.1.2.2 Gridstream Wireless Field Area Network

The Landis+Gyr Gridstream wireless FAN provides full two-way wireless mesh communication and functionality to electric meters, direct load control devices, advanced distribution automation (ADA) devices and Home Area Network devices enabled with a ZigBee communication module.

Advanced metering and diagnostic information that electric meters provide can be communicated over the network to the Command Center head-end operating system and displayed, reported and interfaced to the MDM, CIS, OMS and other enterprise applications. Figure 1-7 shows a schematic of the Gridstream System for AMI, ADA and Meter-to-HAN Gateway.

Figure 1-7: AMI RF Mesh FAN

1.4.2.1.2.3 Smart Meters

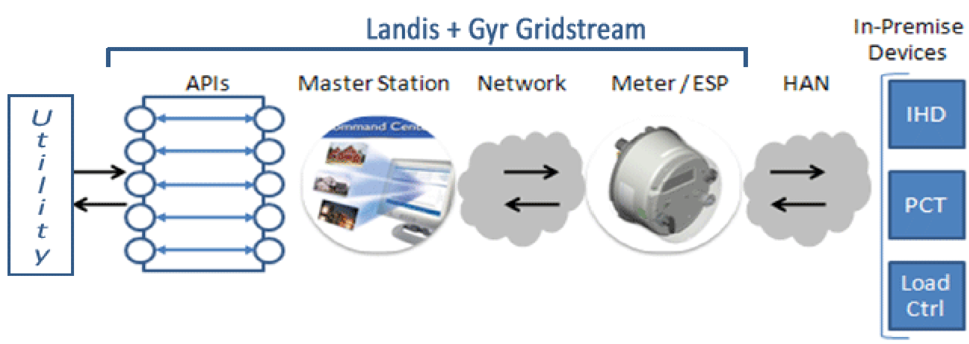
Features of the SmartMeters within the AMI include:

- Full Two-way Mesh Radio AMI Communications
- Variable Output Power
- Auto-registration
- ANSI C12.19 Tables support
- Forward, Reverse, Net, Total Energy
- Voltage/Power Quality Information
- Downloadable Firmware
- Advanced Metering: Demand/TOU/Load Profile
- 5/15/30/60-minute Interval Data Recording
- Data Storage
- Outage and Restoration Notification
- Integrated Service Connect/Disconnect
- Load limiting
- ZigBee Smart Energy Profile HAN Interface
- Reactive Energy & Power Factor (commercial meter only)

1.4.2.1.2.4 HAN Communications via the AMI

The AMI supports HAN applications via the ZigBee-standard Smart Energy Profile (SEP) using the SmartMeter to manage the HAN. This allows KCP&L to communicate usage information, pricing information, and text messages with ZigBee-compliant in-home devices, such as In-Home Displays, Programmable Communicating Thermostats and HAN Gateways.

Figure 1-8: Communication Flow from the AHE to the HAN via the FAN



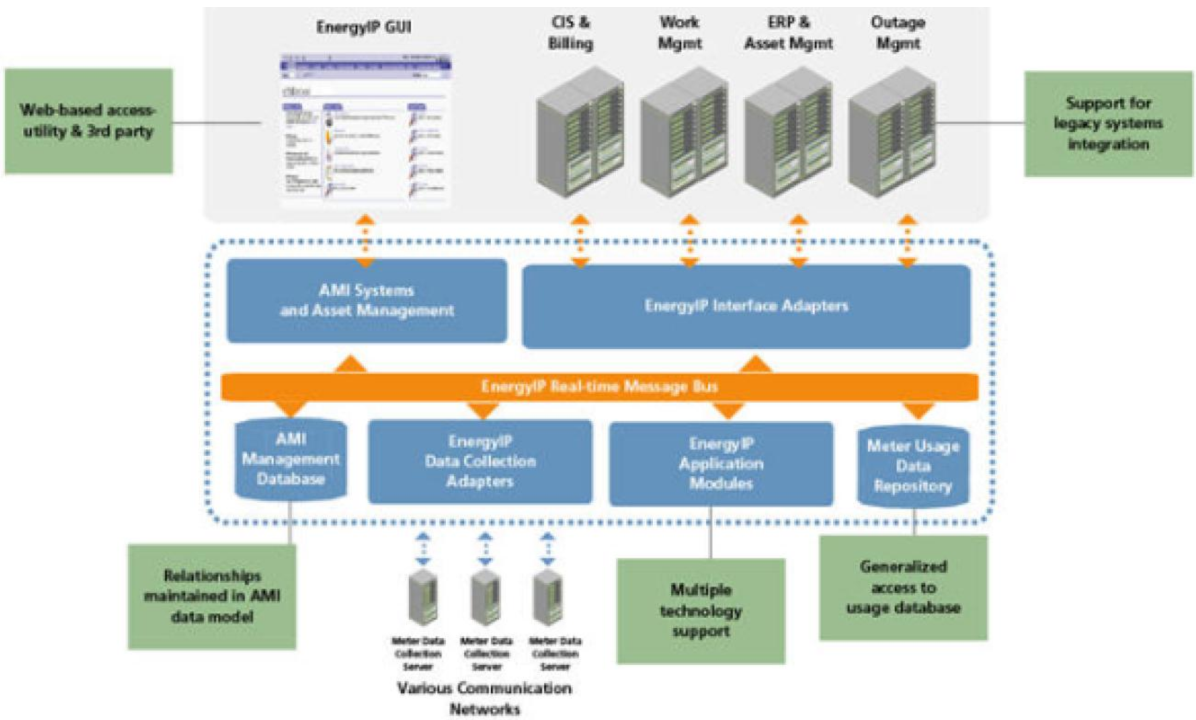
1.4.2.2 Meter Data Management

The MDM provides access, collection, and management capabilities of the consumer metering information for all customers in the KCP&L Green Impact Zone SGDP area, including residential, commercial, and industrial consumers. It stores the customers' 15-minute interval consumption data and daily register read data which is then available to support SmartGrid data analytics and billing for the TOU Billing Pilot Program rates launched in 2012. Other EE/DR incentives may be evaluated using this data in the future. Additionally, the MDM manages the work flow of events and other requests between the legacy CIS and AMI infrastructure for Remote Service Order handling as well as integration between the AMI and the demonstration OMS for outage analysis. Future avenues for integration may include the demonstration DMS/OMS systems, DERM system, and selected HAN management systems.

1.4.2.2.1 MDM Overview

The eMeter EnergyIP MDM provides the capability for receiving and storing meter interval and register data from the AMI system. Services such as Validation, Estimation, and Editing (VEE) are provided as part of the data storage process to ensure a high level of data completeness and data quality. The EnergyIP platform supports integration with CIS for data synchronization, remote service order processing (i.e. Connects, Disconnects, and On-Demand Reads), and calculation of billing determinants from interval data for use in TOU billing and other advanced billing programs. Additional integration is provided with the AMI infrastructure to capture and manage meter events including outages and restorations generated from the AMI which are then sent downstream to systems, such as the OMS, for further processing.

Figure 1-9: MDM Integration Overview



1.4.2.2.2 MDM Characteristics

This section describes the major characteristics of the MDM system which are being leveraged by KCP&L as part of the SGDP.

1.4.2.2.2.1 AMI Data Store

The MDM's AMI Management Database is the data store that maintains the complex relationships among the meter, account, premise, service point, communications node, AMI infrastructure, and the application services under the direction of the AMI Systems and Services Manager. The AMI Management Database includes all the AMI systems and services management data, object relationships, and histories. This database contains records for assets, premises, accounts, meters, services, service requests, activities, activity outcomes, and more. This database tracks not only the current status but also the historical relationships.

The EnergyIP Data Synchronization Engine (DSE) will use the FlexSync process to manage the synchronization of data maintained in the AMI Data Store data with the CIS, and other core utility business systems. FlexSync provides incremental, transactional based approach to synchronizing data and ensures that any changes in data elements or relationships such as meter changes, rate changes, move-in move outs, and other changes to customer premise or service delivery point information are identified and reflected in EnergyIP.

1.4.2.2.2.2 Meter Usage Data Repository

At the core of the MDM's capabilities is the ability to store large amounts of meter-generated data. The Metered Usage Data Repository (MUDR) is the data store that maintains the meter readings, register reads, interval records, outage and restoration events, and event logs. The MUDR also maintains derived or computed data.

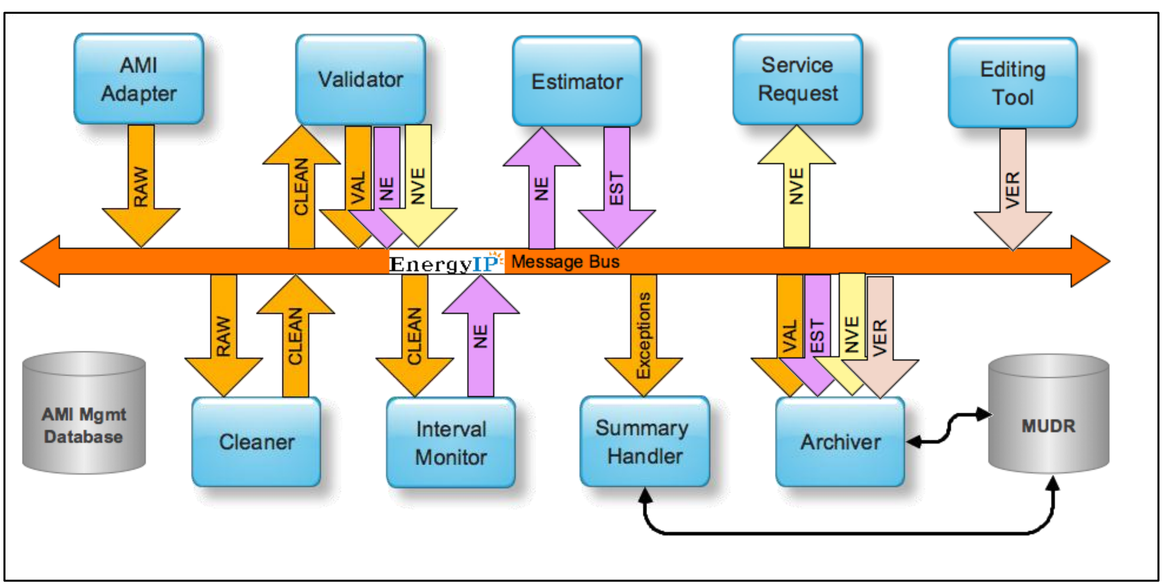
For the KCP&L SGDP, this includes daily register reads and 15-minute interval reads for the 14,000 AMI meters deployed to the SGDP area, or roughly 1.3M interval reads per day to go with 14,000 register reads. Once in the MDM repository, the MDM can provide aggregations of data across various levels including circuit, feeder, substation and transformer. It can also export this VEE'd data for use in downstream systems such as the Data Mining and Analysis Tool (DMAT), Distributed Energy Resource Manager, and Home Energy Management Platform.

The MDM also provides storage for all historical meter read data from the beginning of the SGDP AMI-rollout in October 2010; full history will be retained for the duration of the SGDP for each meter. This is a significant improvement over what would otherwise be available from the AHE or meters themselves.

1.4.2.2.2.3 Validation, Estimation, and Editing

The MDM delivers Validation, Estimation, and Editing (VEE) capabilities that provide estimations for missing intervals, and ensure more reliable, accurate interval data posted to the Meter Usage Data Repository. The Validation module performs validation according to user-configurable rules associated with each data stream; these validations include checks for usage spikes, reverse rotation, etc. Where possible, the Estimation module will follow a defined set of rules to extrapolate and interpolate interval data as well as to estimate register read data when the data is not received from the AMI. There are times when the Validator determines that the interval data needs manual verification and editing and/or when the Estimator is unable to provide a valid estimate.

Figure 1-10: MDM Interval VEE Workflow



For these instances, manual editing via a tabular or graphical view is available within the MDM. In all cases, the MDM also tracks versioning of data when estimation and editing are taking place and provides audit trails for data manipulations.

1.4.2.2.2.4 Usage Framing

The MDM can support multiple usage framing configurations based on a utility's needs. This "framing" sums up a customer's interval data over a specified period of time into a total usage amount for that period and stores it in the appropriate "bin". For example, KCP&L's Time-of-Use (TOU) Billing Pilot Program has established a framing schedule that, on non-holiday weekdays, sums all 16 of a customer's 15 minute interval values between 3PM-7PM to create a "peak" usage bin and the remaining 80 daily interval values between 12AM-3PM and 7PM-12AM to provide an "Off-Peak" usage bin. For weekends and holidays, all 96 daily intervals are added to the "Off-Peak" total. The schedule is further split into summer vs. winter seasons – during the winter, all usage is added to the "Off-Peak" bin. As the MDM can support multiple framing configurations, when KCP&L considers additional custom programs in the future such as critical peak pricing, electric vehicle (EV) charging (aka super-off-peak pricing), or simply different TOU schedules, these can all be set up in the MDM for framing into the appropriate usage bins. Each of these framing programs can also be configured to be setup on specific subsets of customers which further enables the utility to deliver advanced billing solutions to its customers.

Figure 1-11: Usage Framing for TOU

Season	ProfileID	Weekday	TOU BIN	Season	ProfileID	Weekend	TOU BIN	Season	ProfileID	Holiday	TOU BIN
Winter	1	00:00-08:00	1	Winter	1	00:00-00:00	1	Winter	1	00:00-00:00	1
		08:00-21:00	3								
		21:00-00:00	1								
Summer		00:00-08:00	1	Summer		00:00-00:00	1	Summer		00:00-00:00	1
		08:00-12:00	3								
		12:00-18:00	2								
		18:00-23:00	3								
		23:00-00:00	1								

1.4.2.2.2.5 Billing Determinant Calculator

The MDM Billing Determinant Calculator provides the flexibility to compute the billing determinant values based on utility defined formulas. Formulas are built around logical and arithmetic operators, and can contain other billing determinants, constants, and customer functions. In addition to traditional billing, MDM billing determinant calculator can support various advanced billing programs such as TOU billing, critical peak pricing, EV charging rates, etc. as desired by the utility.

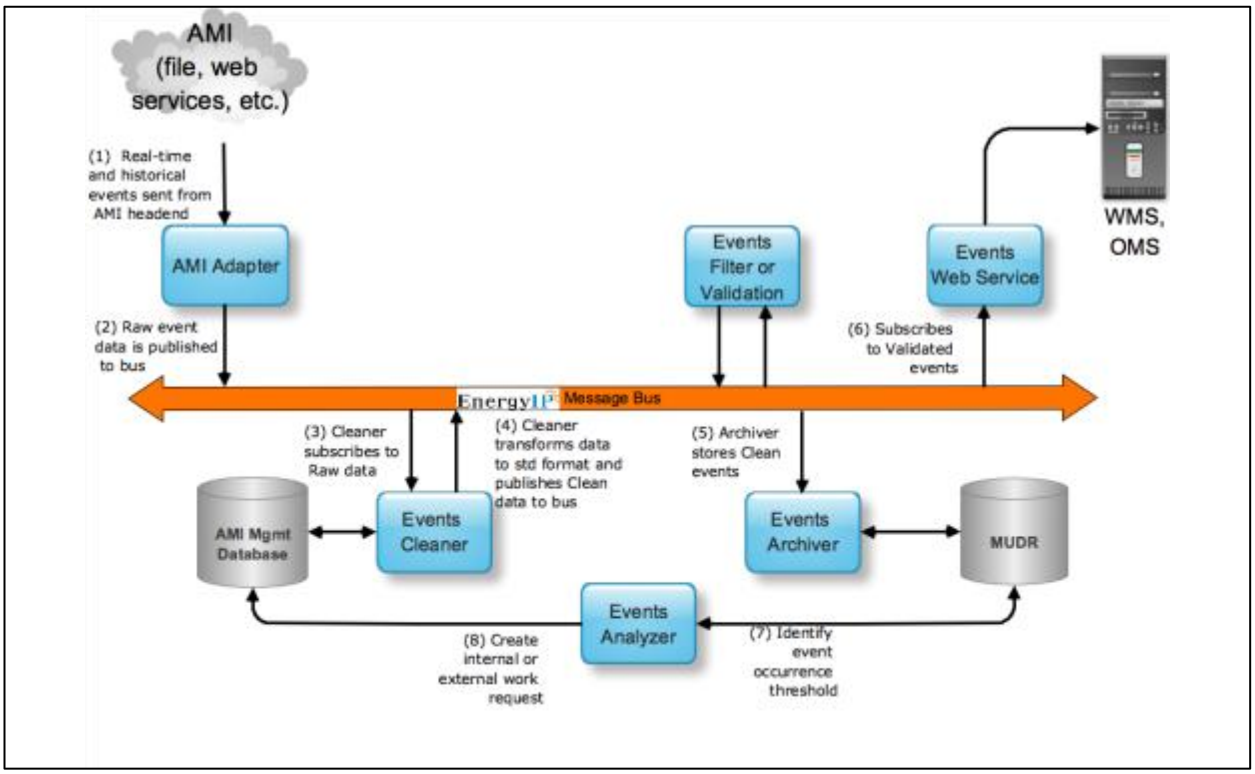
The MDM provides a variety of methods to calculate and deliver billing determinant information to a utility's CIS system. This can be done in a batch format that matches bill cycles/billing routes and delivers a customer's total usage for the month or at various other more customizable levels. The billing determinants can be delivered in both a "Push" method where the MDM produces and delivers a file on a set schedule or in a "Pull" method where the CIS system makes the request for data to the MDM and receives the necessary response back

KCP&L is currently using a modified version of the Pull Billing process to support its TOU Billing Pilot Program. The TOU rate schedule (summer/winter seasons and On-Peak/Off-Peak times) and rate programs (1TOUA for standard customers and 1TOAA for all-electric customers) are set up in the MDM to drive usage framing as noted above. This framed usage is then retrieved via an "off-cycle", "informational" request to the MDM Pull Billing interface. This type of request supports KCP&L's daily retrieval of the On-Peak/Off-Peak bin values for TOU customers. These daily usage values are then processed through KCP&L's SmartGrid middleware which converts them to virtual daily dial values for each TOU bin. These values are then fed into the CIS system when needed for monthly bill cycle processing.

1.4.2.2.2.6 Meter Event Management

In addition to meter readings and usage information, the MDM also is a repository for meter events such as outages, restorations, alarms (i.e. tampering) and operational activities (i.e. demand resets). MDM provides the capability to interface with the AMI to collect event messages generated directly by the meter for outage, restoration, tamper and diagnostic issues. Service order based events are also tracked and stored in the MDM system for activities including remote connects, remote disconnects and on-demand reads. MDM has the ability to generate reporting on these events as well.

Figure 1-12: MDM Event Handling Overview



With the exception of the outage/restoration events which are described in more detail below, KCP&L is currently capturing and storing event messages in the MDM; future projects may build additional interfaces and reports to utilize this information. Events being tracked in the MDM are listed in Table 1-5.

Table 1-5: MDM Events Tracked

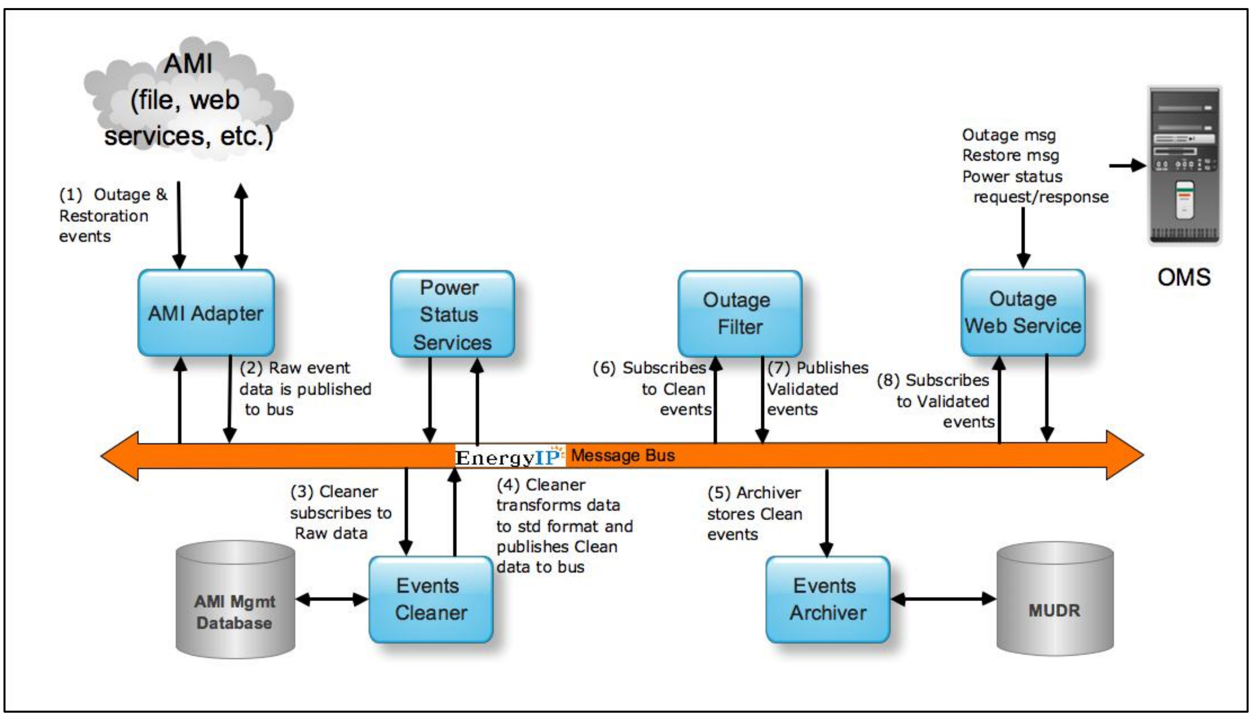
Event Number	Event Description
3.18.1.199	RAM Failure Detected event mapping
3.18.1.220	ROM Failure Detected event mapping
3.2.1.149	Meter Battery Low event mapping
3.21.1.173	Non-volatile Memory Failure Detected event mapping
3.21.1.213	Meter Reprogrammed event mapping
3.21.1.52	Fatal Error
3.21.1.79	Measurement Error Detected event mapping
3.21.1.81	Event Log Cleared event mapping
3.21.1.95	History Log Cleared event mapping
3.21.18.79	Self-Check Error Detected event mapping
3.21.7.79	Meter Configuration Error event mapping
3.33.1.219	Reverse Rotation Detected event mapping
3.33.1.257	Tamper Attempted Suspected event mapping
3.8.1.61	Meter Demand Reset Occurred event mapping

1.4.2.2.2.7 Outage Event Management

As noted above, the MDM receives outage and restoration events generated from the AMI system. The EnergyIP MDM has a number of additional functionalities that provide outage related information, collectively referred to as the Outage Management Support Module (OMSM). The OMSM delivers outage events received from the AMI system to the utility's OMS in an intelligent manner.

Once outage events are received by the MDM, configurable business rules can be applied to filter the raw outage information prior to transmitting it along to the OMS system. These filtering rules include

Figure 1-13: MDM Outage/Restoration Event Handling



managing the time stamps on events that may be transmitted multiple times to prevent the repetitive messages from having to go downstream to the OMS as well as monitoring for de-bouncing scenarios where the outage and restoration come into the MDM in a very short time span. The MDM also provides a bellwether capability as well as critical infrastructure monitoring capability for designated meters; neither of these functions are being used currently by KCP&L in the MDM. The MDM workflow can also provide integration support for Power Status Verification requests made by the OMS system and transmitted down to the AMI through the MDM.

The outage and restoration events configured in the KCP&L MDM are listed in Table 1-6.

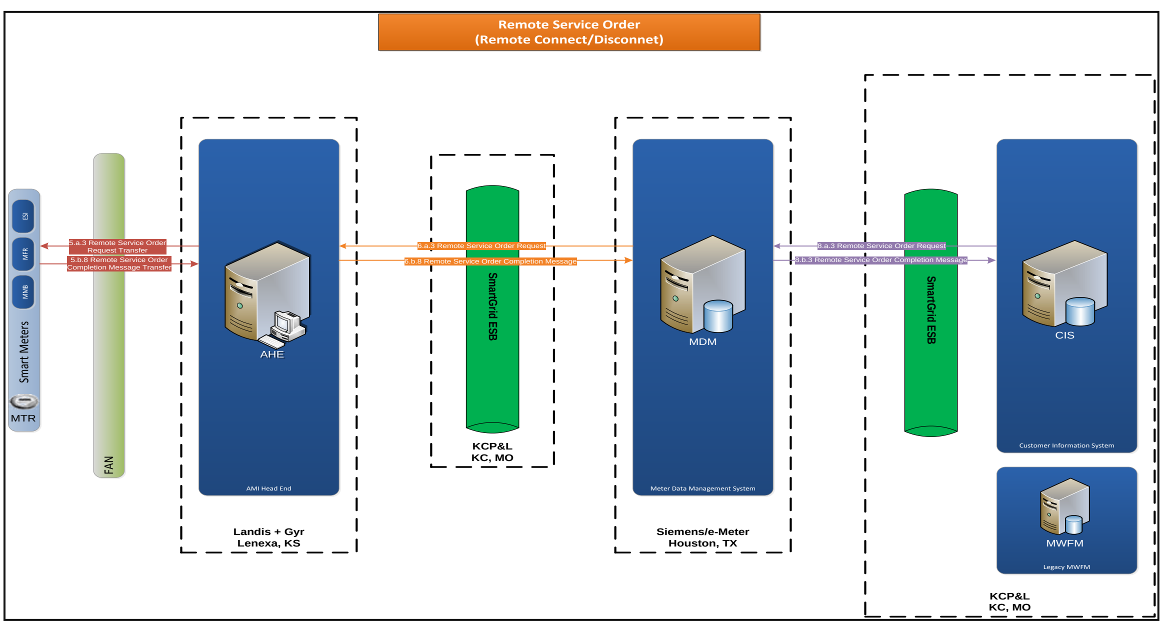
Table 1-6: Outage Restoration Events

Event Number	Event Description
3.26.9.185	Endpoint Power Outage
3.26.9.216	Endpoint Power Restore
3.26.17.185	Primary Power Down
3.26.17.216	Primary Power Restore

1.4.2.2.2.8 Remote Service Orders

The MDM provides the capability for integration with the CIS and AHE systems to provide workflow management for various service orders, including remote connects, remote disconnects and on-demand reads (ODR). As part of this integration, MDM receives a single order from the CIS and breaks it down into the appropriate components – i.e. disconnect and ODR or reconnect and ODR – to be sent down to the AHE in the appropriate order. As part of the workflow, the MDM will send the initial request (i.e. ODR) to the AHE and then wait for the response prior to sending the second part of the service order (i.e. disconnect) down to the AHE. Once the necessary responses for all messages in the workflow are received from the AHE, the MDM then packages them into a single response that is then sent back to the CIS for processing. In addition to supporting integration with the CIS for these order types, the MDM also supports manual entry (if needed) of these service requests directly in the MDM.

Figure 1-14: MDM Remote Service Order Handling Overview

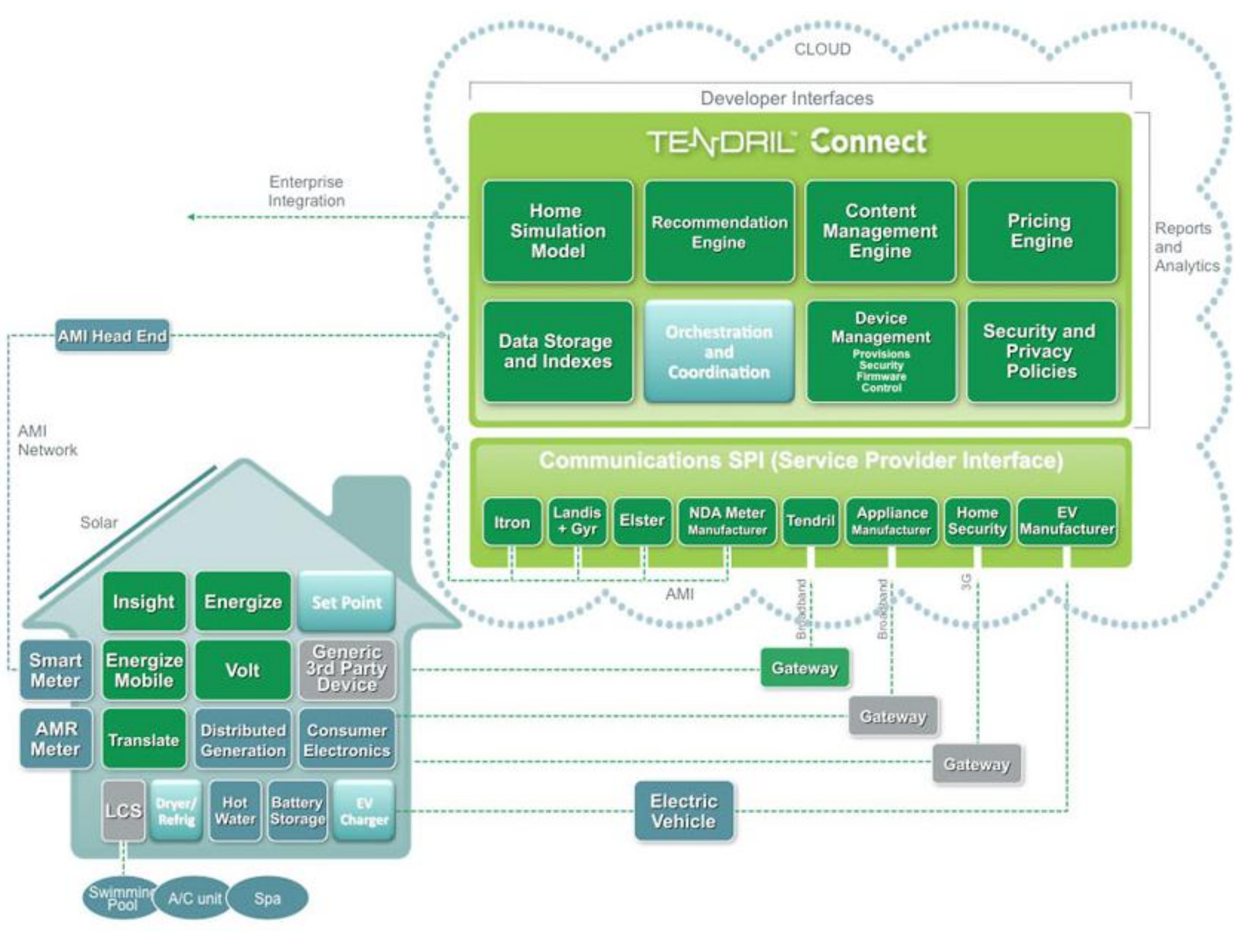


1.4.3 SmartEnd-Use

The SmartEnd-Use subproject deployed a Home Energy Management Platform (HEMP) and Time-of-Use (TOU) rate plan to increase customer adoption of consumption awareness and management techniques, as well as expand KCP&L's demand management capabilities. Together, the HEMP and TOU rate enable customers to directly manage their energy consumption and associated costs. Furthermore, the HEMP provides KCP&L with demand response assets that can be called on during peak demand times to help increase distribution grid stability and decrease operating costs.

A smart grid contains advanced technology that enables enhanced, two-way communication between a utility and its customers. The HEMP provides KCP&L a means to monitor customer involvement, communicate billing and consumption information to customers, and manage demand response assets. In turn, the HEMP provides customers with information to understand their energy consumption and costs and tools to help manage both. The HEMP enables KCP&L to implement and evaluate several technologies that facilitate both indirect and direct load control by providing customers with energy education tools and in-premise Home Area Network (HAN) devices, thus empowering customers to better manage energy consumption and costs. These tools also serve the added benefit of preparing customers for dynamic pricing as well as a means for utilities to communicate pricing signals and billing information.

Figure 1-15: Tendril™ Connect Platform Architecture



The HEMP is a system that interfaces with other back office systems to exchange various data, including energy consumption, billing plans, demand response events and information about various in-premise HAN devices. The HEMP is composed of two main components: 1) a web-based portal that provides KCP&L with access to manage customer accounts and devices and provides customers with access to their historic energy usage information and tips for managing energy consumption, and 2) the ability to manage the in-premise HAN devices, monitor real-time usage, and set preferences for responses to demand response events and pricing programs. KCP&L uses the Administrative Portal to monitor and manage Customer Portal accounts and HAN devices. The customer uses the Customer Portal to view their energy consumption, billing plans, and demand response events and manage their in-premise HAN devices.

1.4.3.1 Customer Web Portal

1.4.3.1.1 Customer Web Portal Overview

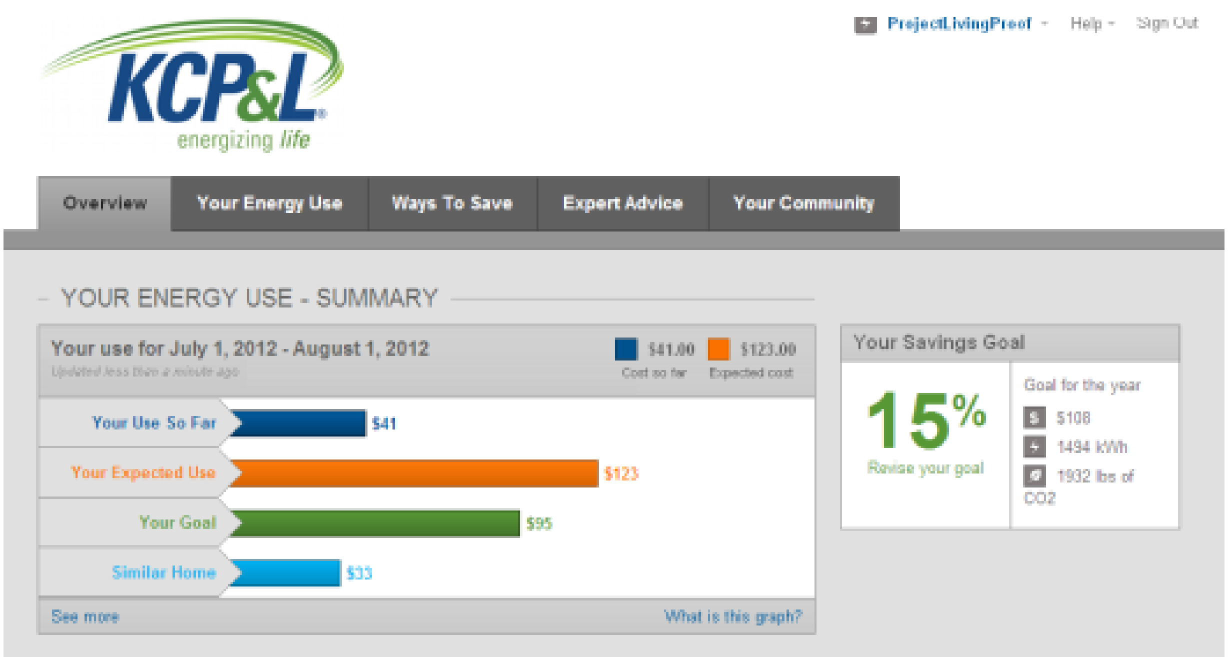
The Customer Web Portal is a full featured informational web portal that is designed to give customers access to their detailed energy usage and help them better understand the impact of their electricity usage on their bills. It also provides additional recommendations and information to encourage them to make decisions that conserve energy, help the environment, and save money.

1.4.3.1.2 Customer Web Portal Characteristics

KCP&L's Customer Web Portal, shown in Figure 1-16, is designed to show a customer how much and when they use electricity each day and help them estimate their bill, including taxes and charges, before they receive it.

Traditionally, electricity customers have used energy without knowing how much money they were spending and when. Now, for example, on a hot summer day customers will be able to see exactly when usage goes up. This information may influence customers to use electricity differently at those times and receiving it in near real-time through in-premise HAN devices facilitates immediate action to manage energy consumption and costs instead of waiting for a monthly bill to see this information.

Figure 1-16: Customer Web Portal



The Customer Web Portal allows customers to:

- See energy usage information in easy-to-understand charts
- Estimate their current monthly bill
- Compare this month's bill against last month's bill
- Evaluate hourly, daily, and monthly electricity usage amounts
- Review yearly billing history
- Compare their usage against other homes in their community
- Receive messages from KCP&L about their usage

1.4.3.2 In-Home Display

1.4.3.2.1 IHD Overview

The In-Home Display (IHD) is a portable electronic device that provides real-time energy usage information to customers directly from their meter to increase awareness of electricity usage and help identify opportunities to reduce consumption and save money. The IHD receives information directly from a customer SmartMeter and presents it to them in easy-to-understand screens.

1.4.3.2.2 IHD Characteristics

The IHD communicates with the SmartMeter wirelessly via an IEEE 802.15.4 network running the ZigBee SEP 1.0 specification to receive real-time energy consumption data, pricing signals, text messages, and estimated billing information. The IHD does not require an Internet connection.

The IHD, shown in Figure 1-17, provides customers with:

- Current electricity usage information
- Current electricity costs
- Important text messages from KCP&L
- Up-to-date current month usage and estimated billing information

The IHD allows a customer to set a price limit on how much electricity they want to use for the month. It will then visually notify customers with green, yellow, and red backlighting indicating whether they are meeting, nearing, or exceeding that limit. The IHD only receives and displays energy usage information and does not directly affect customer energy consumption; it simply sends warning signals to influence energy consumption in order to meet the customer-imposed limits, thus enabling customers to manage their consumption and costs.

Figure 1-17: In-Home Display

1.4.3.3 Stand-alone Programmable Communicating Thermostat

1.4.3.3.1 Stand-alone PCT Overview

The Stand-alone Programmable Communicating Thermostat (PCT) is an electronic device that receives information directly from a customer SmartMeter to allow customers to participate in utility-initiated demand response events. The Stand-alone PCT provides customers a means to better manage their heating and cooling consumption costs by enabling them to program a weekly heating/cooling schedule, participate in demand response events, and receive real-time pricing signals and text messages from KCP&L.

1.4.3.3.2 Stand-alone PCT Characteristics

The Stand-alone PCT communicates with the SmartMeter wirelessly via an IEEE 802.15.4 network running the ZigBee SEP 1.0 specification to receive real-time pricing signals, demand response events, and text messages. The Stand-alone PCT does not require an Internet connection.

The Stand-alone PCT, shown in Figure 1-18, provides customers with the ability to:

- Receive real-time pricing information
- Receive demand response event information from KCP&L
- Opt-in/out of demand response events at the thermostat
- Program temperature set points for the thermostat
- Receive important text messages from KCP&L

Figure 1-18: Stand-alone PCT

The Stand-alone PCT allows customers to set schedules for their heating and cooling needs throughout the week. Customers can set four different temperature set points for both heating and cooling throughout each day of the week. This helps customers better manage their heating/cooling loads when they are away from their homes. The Stand-alone PCT also includes different temperature modes, such as “Hold” and “Vacation”, which offer customers more flexibility in managing their consumption.

Program participants will have their Stand-alone PCT enrolled in the SmartGrid demand response program. When a demand response event occurs, customers are notified ahead of time with information about the event start time and duration. By default, customers are opted into each event. However, once customers receive the event, they can opt-out or back in at any time before the event concludes. Customers can make this opt-in/out decision at the Stand-alone PCT. Event participation is recorded for post-event evaluation and analytics.

1.4.3.4 Home Area Network

1.4.3.4.1 HAN Overview

The HAN is a suite of electronic devices that receive information directly from a customer SmartMeter to increase customer awareness of electricity usage and help identify opportunities to reduce consumption and save money. The HAN provides customers a means to better manage their heating, cooling, and simple load consumption costs by enabling them to program a weekly heating/cooling schedule, program pricing schedules for each device, participate in demand response events, and receive real-time pricing signals and text messages from KCP&L.

1.4.3.4.2 HAN Characteristics

The HAN communicates with the SmartMeter wirelessly via an IEEE 802.15.4 network running the ZigBee SEP 1.0 specification to receive usage information, pricing signals, and text messages. Included in the suite is a gateway device, a PCT and a pair of 120V Load Control Switches (LCS). An optional 240V LCS may be included for customers with a larger controllable electric load, such as a water heater or pool pump.

The HAN, shown in Figure 1-19, provides customers with the ability to:

- Receive real-time pricing information
- Receive demand response event information from KCP&L
- Opt-in/out of demand response events at the thermostat and load control switches
- Remotely monitor and control the devices via the Customer Web Portal
- Program temperature set points for the thermostat
- Program pricing rules for the load control switches
- Receive important text messages from KCP&L

Figure 1-19: Home Area Network Devices

The gateway within the HAN establishes an IP connection with the Customer Web Portal via the customer supplied internet connection, enabling customers to manage energy consumption in their home using the functionality provided by the HEMP. The gateway device receives real-time usage information directly from the customer SmartMeter. This usage information is passed to the Customer Web Portal to be displayed to the customer. The gateway also transfers control commands from the Customer Web Portal to the PCT and LCSs. This enables customers to remotely manage device schedules and rules, control devices, and manage demand response event participation.

The PCT within the HAN allows customers to set schedules for their heating and cooling needs throughout the week. Customers can set four different temperature set points for both heating and cooling throughout each day of the week. This helps customers better manage their heating/cooling loads when they are away from their homes. The PCT also includes different temperature modes, such as “Hold” and “Vacation”, which offer customers more flexibility in managing their consumption.

The LCSs within the HAN allow customers to set pricing rules for the simple loads attached to the LCSs. This enables the device to respond and operate to changes in electricity rates automatically, thus giving the customers added flexibility to help manage energy consumption and costs. The LCSs also report individual device consumption data to the Customer Web Portal to be displayed to customers. This feature enables customers to better understand the energy consumption and operating costs of individual appliances within their homes.

Program participants will have their PCT and LCSs enrolled in the SmartGrid demand response program. When a demand response event occurs, customers are notified ahead of time with information about the event start time and duration. By default, customers are opted into each event. However, once customers receive the event, they can opt-out or back in at any time before the event concludes. Customers can make this opt-in/out decision at the PCT, the LCSs, or the Customer Web Portal. Event participation is recorded for post-event evaluation and analytics.

In conjunction with new voluntary TOU rate options and the energy management capabilities that the HAN provides, it is expected that the HAN users will reduce their overall kWh usage, shift load to off peak times, and voluntarily allow HAN-connected devices to participate in demand response events.

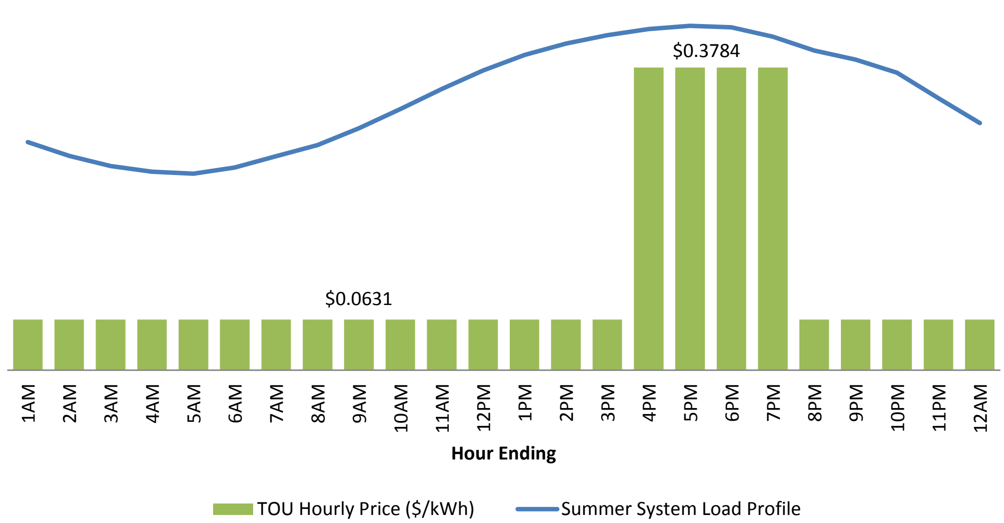
1.4.3.5 Residential Time-of-Use Billing Pilot Program

In response to a request from the Missouri Public Service Committee (MPSC) and in conjunction with the KCP&L SGDP that included AMI metering, KCP&L implemented a process by which KCP&L is able to bill a new Missouri time-of-use (TOU) pilot tariff through the CIS system based on usage information collected from AMI meters and stored in the MDM.

The initial pilot tariff went into effect on January 1, 2012 and consists of two daily periods in the summer months: an On-Peak period and an Off-Peak period. Summer On-Peak periods occur over a defined hourly range (a four hour period that will start and end on the hour from 3pm-7pm) on summer weekdays and non-holidays. The summer season runs from May 16th to September 15th, inclusive. The tariff expires at the end of the SGDP pilot on December 31, 2014.

Participating customers receive monthly bills that include usage information grouped into the three TOU period categories of peak summer, Off-Peak summer, and winter usage. They are also able to view TOU cues in the HEMP and IHDs, if they are participating in those programs.

Figure 1-20: KCP&L System Load Profile and TOU Rates



1.4.3.5.1 TOU Overview

While designed to be revenue neutral for KCP&L average residential customers, the pilot TOU tariff provides greater incentive for customers to shift load from peak periods to Off-Peak periods due to the significant difference between peak and Off-Peak prices during summer months. Off-peak prices of these tariffs represent a tangible opportunity for customers to shift load and save money on their annual electricity expenses without reducing overall usage.

Successful peak load shifting benefits KCP&L by reducing burdens on inefficient generators and limiting strain on various components of the distribution system resulting in more efficient and more economical delivery of electricity to customers. This project will also provide key inputs to the overall DOE SGDP analyses and reporting.

1.4.3.5.2 TOU Characteristics

Two pilot TOU tariffs offer one summer rate structure: peak period of 3-7pm. Peak periods for both tariffs occur on summer weekdays, excluding holidays. Summer is defined as May 16th through September 15th, inclusive. During the summer season, a flat peak price is applied to all energy used during defined peak hours and a flat Off-Peak price is applied to energy used at all other times. The customer's standard rate would apply to all energy used in the remainder of the year, considered the winter season. Table 1-7 summarizes tariff details.

Table 1-7: Pilot TOU Tariff Details

Rate Codes	
1TOUA – TOU Rate for Residential Standard Customers currently on 1RS1A rates	
1TOAA – TOU Rate for Residential All-Electric Customers currently on 1RS6A rates	
Schedule	
Peak Rates are charged from 3PM – 7PM Central on non-holiday weekdays (Monday-Friday) during Summer Season; weekends (Saturday-Sunday) and holidays are billed at discounted Off-Peak rates	
Summer Season: May 16th through September 15th (inclusive)	
Winter Season: September 16th through May 15th (inclusive)	
Holidays observed during Summer Season include Memorial Day, Independence Day and Labor Day	
Pricing	
TOU Summer Peak Price:	$0.3784/kWh
TOU Summer Off-Peak Price:	$0.0631/kWh
TOU Winter Price:	Declining Block; same as standard rates
Excluded Customers	
Dual meter customers	
Net metering customers	
Customers w/ Current Transformer greater than 1.0	
Business Rules	
Customer can sign-up anytime during the year; however, the rates will not be affected until the first day of their next billing cycle	
Customer may exit the program anytime; however, they cannot join again during the remainder of the pilot period, which ends on December 31, 2014	
Other Considerations	
Upon request, customers exiting the program will be refunded any TOU charges in excess of what their bill would have been under the standard rates for the current and previous billing cycle.	
Enrollment occurs at the start of a billing period and customers who elect to exit the program may have their exit backdated to the start of the previous billing period	

1.4.4 SmartSubstation

The Midtown SmartSubstation implementation will consist of new microprocessor based protective relays, a new substation protection and control network (SPN), Human Machine Interfaces (HMIs), substation data concentrators, substation controllers, and applications. The SmartSubstation will operate KCP&L's substation with advanced functionality to provide more reliability, efficiency, and security.

Upon completion of the SmartSubstation implementation, KCP&L will be able to demonstrate the following functions:

- Peer-to-peer communication between IEDs via IEC 61850 GOOSE messages
- Controlling the tap changer of the transformers and the smart grid feeder breakers via IEC 61850 MMS messages
- Protection of substation devices, assets and feeders
- Redundant data collection concentration in the substation
- Redundant local HMI
- Cyber security through use of firewall rules and VLANs
- Physical security through electronic access control and NERC-compliant logging tools
- Redundant TCP/IP communication between substation and DMS SCADA system
- Smart applications in the substation that operate in closed-loop mode
- Volt/VAR management using tap changers and capacitor controllers
- Feeder overload management via Dynamic Voltage Control
- Fault management applications performed in conjunction with devices on the feeders (via the substation controller)
- Automated switching procedures to isolate faults on the feeders and provide service restoration
- Relay metering including calculations for real power, reactive power, apparent power, etc.

1.4.4.1 Substation Protection Network Upgrade

1.4.4.1.1 SPN Upgrade Overview

This project includes upgrades to protection and control equipment and the deployment of an Ethernet-based substation control network utilizing the IEC 61850 network architecture. This effort requires the Network Services, Substation Protection, and Relay System Protection departments of KCP&L to work together to design, provision, and operate this joint network. The IEC 61850 network should be treated like any other protection and control system, and should only be used for protection and control purposes.

The existing electromechanical relays at Midtown Substation will be replaced with new microprocessor relays (Intelligent Electronic Devices). These IEDs will have communication capabilities utilizing IEC 61850 in the protection and automation system. The IEC 61850 implementation will allow KCP&L to minimize wiring in the substation and provide automation such as interlocks through this digital system.

1.4.4.1.2 SPN Upgrade Characteristics

Substation protection and control networks are deployed in harsh environments and transport critical data. As such, the network and its components have demanding requirements. The network must have high availability and low latency, providing fast, reliable communication between networked devices. Networking equipment deployed in these networks must be environmentally hardened, as it may be deployed in enclosures with limited climate control, requiring the equipment to operate across extreme humidity and temperature ranges. Therefore, a reliable physical architecture for the network is needed along with ruggedized, highly reliable network components.

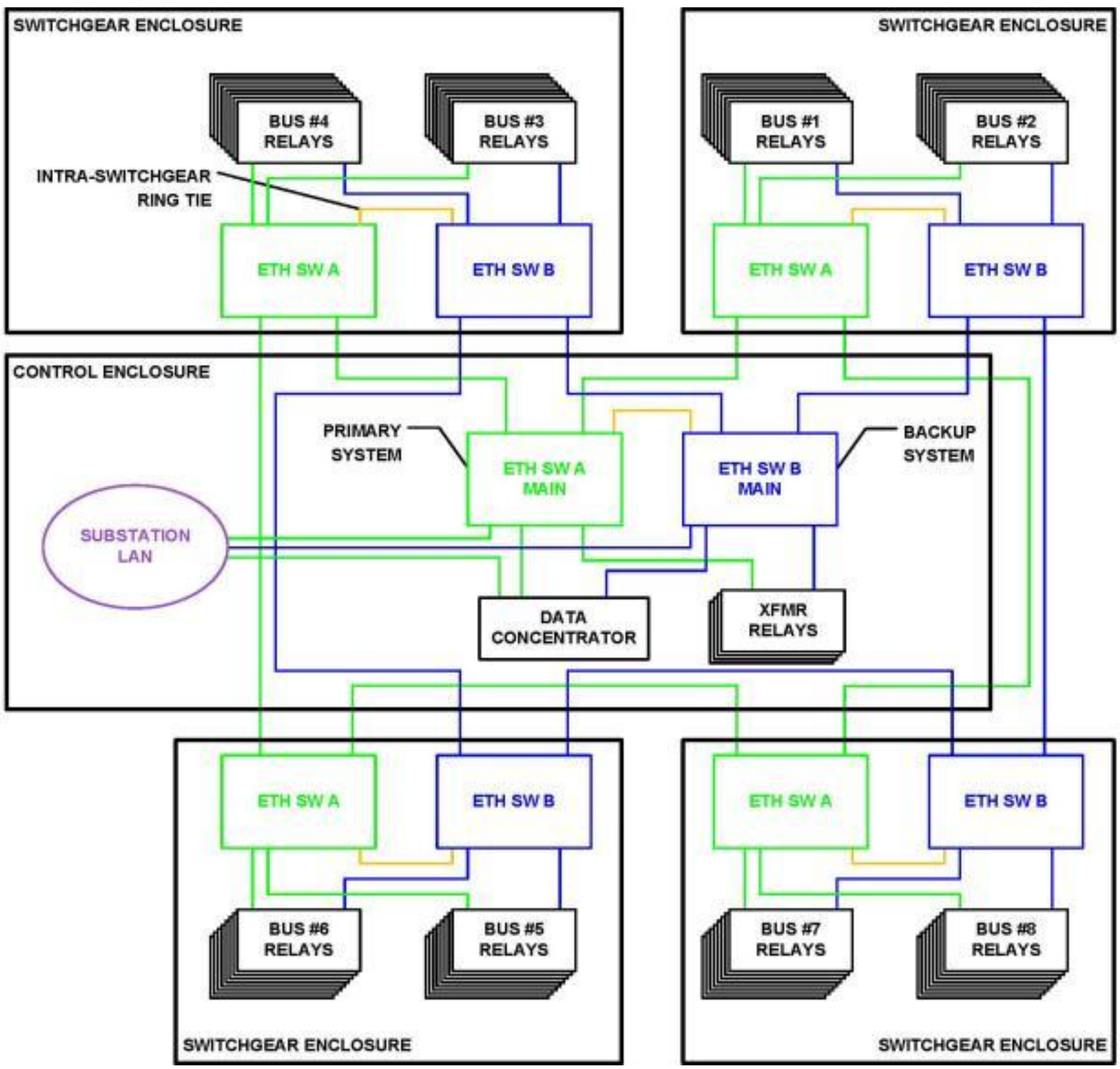
The IEC 61850 Midtown Substation control network configuration [4] consists of redundant 1 Gbps Ethernet backbones routed throughout the substation. These backbones will interconnect remote primary and backup Ethernet switches installed in various switchgear enclosures to main Ethernet switches located in the main control enclosure. Protective relays, equipped with redundant Ethernet ports, will connect to the appropriate primary and backup remote switches using 100 Mbps Ethernet.

The Midtown Substation control network topology was chosen to achieve the following:

- Provide high-bandwidth, low-latency communications
- Minimize or eliminate single points of failure for cabling and equipment
- Minimize infrastructure costs

The Midtown Substation protection and control network architecture is shown in Figure 1-21.

Figure 1-21: Midtown Substation Protection and Control Network Architecture



The IEC 61850 network was designed as a redundant Ethernet ring architecture. Ring architectures allow for self-healing networks, increasing availability and reliability. The Ethernet switches comprising the network are arranged in rings, providing redundant pathways between two points in the network via the Ethernet backbone. This configuration protects against loss of communication between devices due to failure of a communication link or loss of an intermediate switch. Loss of communication only occurs when there is a failure in the edge switch to which one of the two communicating devices is connected. To further increase reliability, redundant rings can be deployed. This allows devices with redundant Ethernet interfaces to take advantage of a standby Ethernet network, reducing the probability of a loss of station control due to failure of any single piece of network equipment. This redundant ring configuration eliminates single points of failure for all Ethernet hardware when the communication devices are configured in fail-over mode.

Aside from enhanced fault recovery, the additional redundancy can significantly ease maintenance of the network, as any single network device can be completely removed from service without network disruption or loss of station control. Direct connections should be made between primary and backup switches in each control enclosure, providing a local link for traffic in the event any enclosure is isolated from the rest of the network.

1.4.4.2 Distribution Data Concentrator

1.4.4.2.1 DDC Overview

The Siemens Integrated Control And Monitoring Power Automation System (SICAM PAS) acts as the Distribution Data Concentrator (DDC) for the substation and field devices reporting to Midtown. The DDC controls and registers the process data for all the devices in a substation. It is essentially a communication gateway, so that only one data connection to a higher-level system control center is required.

1.4.4.2.2 DDC Characteristics

The SICAM's networking and IT capabilities, interoperable system structure, and integration with existing systems are designed to simplify configuration and commissioning and help to increase the efficiency of operations management. The SICAM is capable of polling for data collection, power monitoring, control automation and system-wide visualization. The over-arching goals of the SICAM are to increase the reliability and availability of KCP&L's systems, leading to a stable power supply.

The SICAM PAS is capable of communicating via the following:

- IEC 61850
- DNP3
- Modbus
- OPC
- Profibus
- TG8979

For KCP&L's SGDP, the SICAM will utilize DNP3 to communicate with the field devices and IEC 61850 to communicate with the substation devices. The 61850 communications in the substation will utilize the manufacturing messaging specification (MMS). The devices will send the SICAM annunciators and metering values. The SICAM will send the devices control messages. Rather than implementing a typical SCADA poll, the devices will be configured to have unsolicited reporting enabled. When one point's instantaneous magnitude crosses a pre-defined deadband threshold, the device will send the SICAM the magnitude of all the points in its 61850 report.

During the pilot, serial communications will be maintained to each relay from the substation remote terminal unit to support dual communications with the relays from the existing energy management system (EMS).

1.4.4.3 Human Machine Interface

1.4.4.3.1 HMI Overview

The substation Human Machine Interface (HMI) provides a local view of all of the equipment located inside the fence of the substation. The purpose of the HMI is to give substation personnel a tool for viewing the current status of the equipment within the substation, as well as giving them the potential to operate the smart grid devices from within the substation control house.

1.4.4.3.2 HMI Characteristics

For this project, the DMS only contains information for one substation, but for a system-wide DMS implementation, the DMS would likely provide a higher level of information about devices at all of the substations, and the Substation DCADA would just be a black box with no graphical user interface. Thus, the HMI would provide this look inside the black box.

Unlike the DMS and the DCADA, the HMI does not contain any information about the field devices. The HMI does, however, provide information about the substation network equipment, which is not displayed in the DMS. Through the HMI, the user will be able to verify whether any substation issues are related to network communications. Each substation device will be connected to a particular network switch and mapped to a specific port. Although the user can't modify any network configurations from the HMI, he will be able to easily determine whether any problems exist on the network prior to engaging the IT personnel at KCP&L.

1.4.4.4 Generic Object-Oriented Substation Event [5]

1.4.4.4.1 GOOSE Overview

As discussed above, for device to controller communications in the substation, 61850 MMS communications will be used. For peer-to-peer communications, however, the substation IEDs will utilize 61850 Generic Object-Oriented Substation Event (GOOSE) messaging.

1.4.4.4.2 GOOSE Characteristics

For the SGDP, KCP&L will be using GOOSE messaging to implement four functionalities described in the following sections depicted in the GOOSE logic diagram, Figure 1-22.

1.4.4.4.2.1 Load Transfer

The load-transfer scheme restores service to customers by automatically closing the tie breaker upon lockout of the transformer. The Midtown Substation design consists of two four-position buses fed from a dual-wound distribution transformer. Tie buses are used for maintenance and emergency backup of station operations when the transformer is removed from operation. The combined load of the two buses can be above the two-hour power rating for the transformer on many of the buses. In the past, a dedicated programmable logic controller (PLC) was used at these locations to calculate the optimal feeder configuration to transfer to the tie bus before the tie breaker was closed. As part of the upgrade, KCP&L wanted this logic to be moved into the relay logic, eliminating the need for the PLC and additional wiring. This objective was achieved through the use of automation logic in a SEL-451 relay, with the real-time event notification capabilities of IEC 61850 GOOSE messaging for inter-relay communications. The feeder relays (SEL-751) were used to publish the individual feeder loads and the total tie-bus transformer load (SEL-487) using IEC 61850 GOOSE messages. The main relay (SEL-451) subscribes to these analog values along with status messages for bus lockout, which triggers the scheme. The main breaker relay continually computes and publishes the optimal feeder configuration to transfer if a fault occurs, based on each feeder's load and available capacity. When each feeder relay sees the scheme-enabled GOOSE message sent, it opens if it is to be shed before the bus tie breaker is closed. This scheme uses the two-hour overload power rating for the tie bus transformer, which gives the distribution operator two hours to reconfigure distribution feeders, thereby relieving the overload condition while continuing to provide service to customers on the affected bus.

1.4.4.4.2.2 Faster Overcurrent Tripping

Implementing a communications-based breaker failure scheme instead of relying on time overcurrent values resulted in the faster overcurrent tripping of main and tie breakers upon feeder breaker failure. When a feeder breaker trips, it sends a GOOSE message to the main and tie breakers indicating an operation where a stuck breaker timer is initiated. If a follow-up breaker-open message is not received within this time, the main and tie breakers trip, thereby clearing the fault. This faster overcurrent tripping scheme and subsequent schemes reduce wear on equipment, decreasing the likelihood of equipment failure and improving customer reliability.

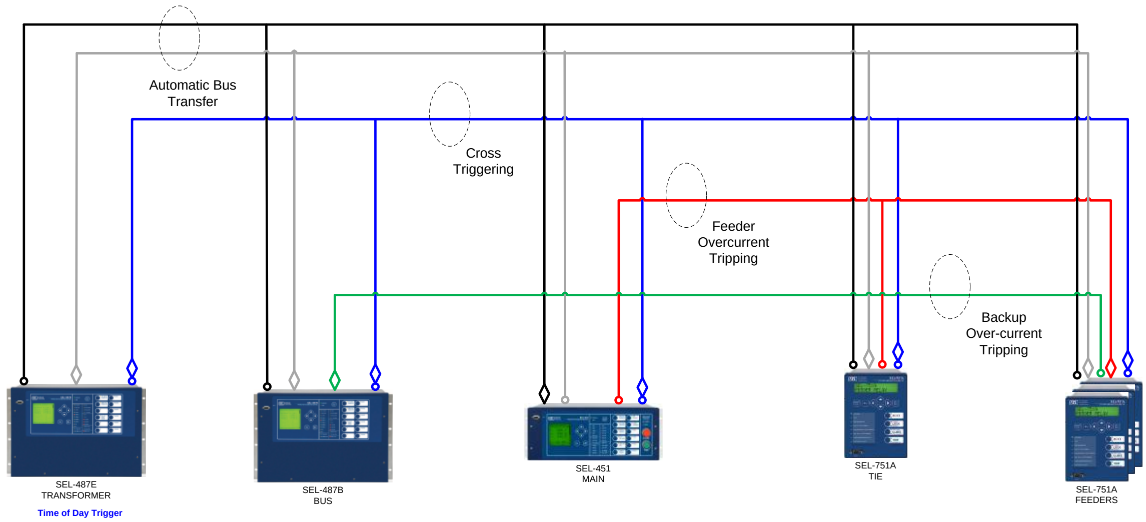
1.4.4.4.2.3 Backup Overcurrent Tripping Scheme

Backup overcurrent protection in the bus differential relay provides redundancy to the logic, sensors and wiring in the feeder relays, allowing them to trip a feeder with a reclosing function if the feeder relay fails to detect or clear a fault. The bus differential relay uses its current circuit and sensor to monitor the feeder, and it is programmed to send a GOOSE-based trip message to the feeder relay, clearing the fault if the feeder relay has not already done so. This scheme and the previous scheme could have been implemented using pre-IEC 61850 protection and control designs and techniques, but they were not cost effective to implement. Using the common communications bus reduces the cost of implementing these additional schemes to programming and testing. Once the schemes are initially developed as part of this pilot, they can be used for future projects at a marginal cost.

1.4.4.4.2.4 Cross Triggering

Cross triggering of all devices for every distribution system event and at a specific time each day provides the engineering department with detailed oscillography and event information. This information explains how the protection and control functions performed under fault conditions. Previously, event information was only available from fault recorders, which were not cost-effective for distribution substations. KCP&L's design leverages the power of relays for recording waveforms and IEC 61850 GOOSE messages to cross trigger devices, enabling station-wide awareness that had been impossible in the past. Analyzing this information allows schemes and settings to be optimized, providing customers with more reliable service.

Figure 1-22: GOOSE Logic Diagram



1.4.4.5 Substation Distributed Control and Data Acquisition System

1.4.4.5.1 DCADA Overview

The Substation Distributed Control and Data Acquisition is the brain of the substation. It receives device status updates from the SICAM, and it determines how to respond to activity occurring on the distribution system.

1.4.4.5.2 DCADA Characteristics

The DCADA can perform many of the same applications as the Distribution Management System, but it does so in a closed loop method, and it can only control devices within its area of control. The DCADA can control any devices within Midtown Substation or any field devices on Midtown feeders.

The Distribution Network Applications that can be performed by the DCADA include:

- Distribution System Power Flow
- Distribution System State Estimation
- Feeder Load Transfer
- Volt/VAR
- Fault Management

If the substation is running in closed loop mode, then the DCADA makes decisions and sends controls to IEDs without the interaction of an operator. In this mode, the DCADA attempts to resolve any issues that arise using its First Responder functionalities. If the DCADA isn't able to solve the problem with its available tools and applications, then the DCADA transfers control to the DMS, where the operator is alerted of the issue and asked for input to solve the problem.

1.4.5 SmartDistribution

The SmartDistribution subproject deployed a state-of-the-art Distribution Management System (DMS) and Advanced Distribution Automation (ADA) network. The DMS for this project will only be used for Midtown Substation, but for an enterprisewide deployment, this DMS would be Central Control for *all* of the distributed intelligent substations and field networks. The DMS monitors and controls the state of distribution network at all times, and serves as the primary point of integration for the facilities, consumer, electrical system, load, distributed energy resource, and real-time substation and feeder information. The DMS includes Distribution Supervisory Control and Data Acquisition (D-SCADA), an Outage Management System (OMS), and a common graphical user interface for operations. It solves reliability issues through its Distribution Network Analyses (DNA) applications.

Some of the key features of KCP&L's SGDP DMS include:

- Provides a single highly efficient user interface for all DMS functions
- Visually correlates and integrates large amounts of field information
- Supports management of outage restoration and mobile work crews
- Utilizes available information from Distribution Automation (DA) and AMI sources
- Provides modeling and simulation of Distributed Energy Resources
- Provides modeling and simulation of intelligent field devices and the supporting protection and control schemes
- Incorporates all available feeder and substation measurements and fault indicators
- Establishes a time-smoothed granular feeder load model for more accurate solutions
- Rapidly and accurately determines fault locations and automatically provides isolation and restoration plan options
- Tracks system/feeder load reduction capacity on an on-going basis
- Supports various optimization objectives, including voltage, VAR, loss, and load capacity management
- Establishes a generalized model-based integration platform for simplified integration with other enterprise systems

For the SGDP, Siemens and Intergraph will provide a packaged solution that satisfies all the components of a Distribution Management System. Siemens will be responsible for the D-SCADA and DNA pieces, and Intergraph will provide the OMS and user interface.

The ADA network consists of a Tropos 2.4/5.8 MHz mesh network, capacitor banks, fault current interrupters, and reclosers. The field devices will communicate back to the substation controller and the DMS. The DNA applications will run in open or closed loop at the DMS, and in closed loop at the substation. These applications will respond to any potential network overloads, and will automatically reconfigure the network as needed.

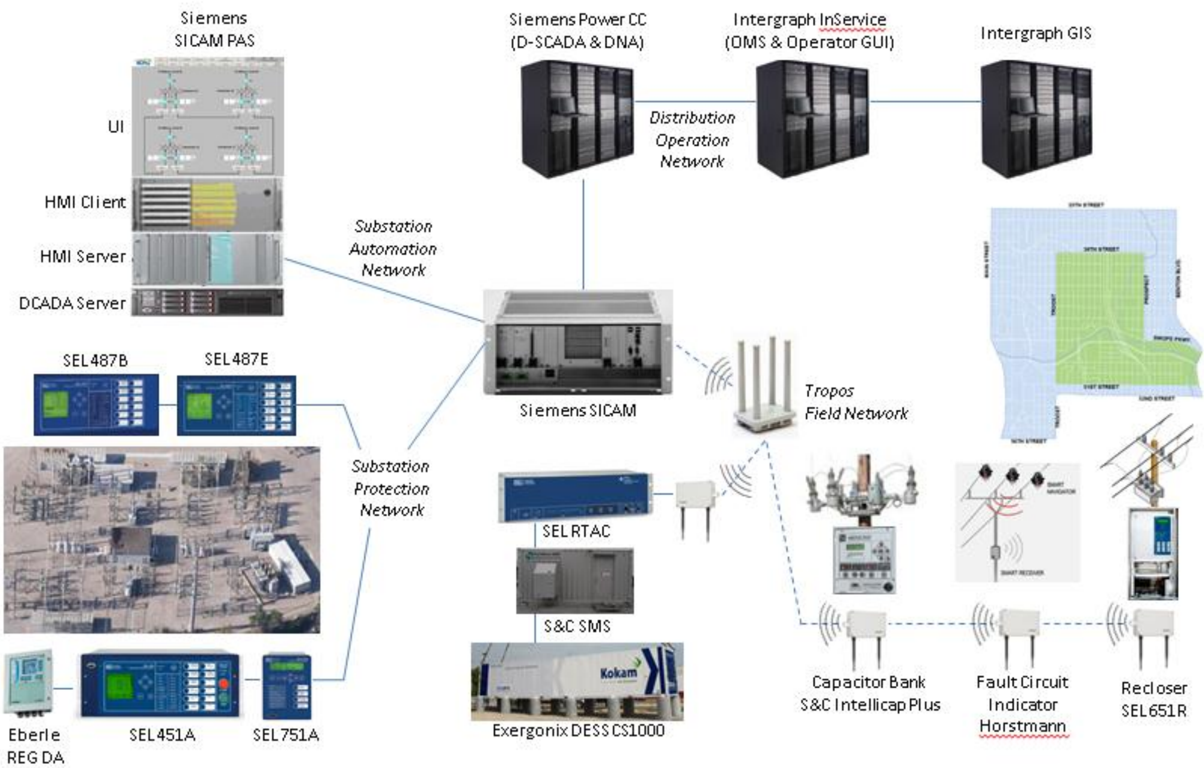
Figure 1-23 shows the components of KCP&L's SmartDistribution implementation.

1.4.5.1 Distribution Management System User Interface

1.4.5.1.1 DMS UI Overview

The DMS user interface (UI) will provide a single comprehensive user environment by which the grid operators will interact with the all DMS components (D-SCADA, OMS, DNA, etc.) and SmartDistribution Functions. The DMS UI will provide a tight integration between DMS components to automate the grid operator's workflow as much as possible and enable efficient transition between major functions.

Figure 1-23: SmartDistribution Components



1.4.5.1.2 DMS UI Characteristics

The DMS UI component of the SGDP DMS is provided by Intergraph's InService system and creates a SmartDistribution operations command and control center that provides the following:

- A common user environment, consolidating multiple control room systems into one user interface to improve situation awareness and reduce human error. The UI allows DMS component applications to be invoked and data/dialogs from these applications to be displayed.
- The geospatial network map display features dynamic colorization and attribute-based symbology that changes with the state of the device. The display can be filtered based on network components or devices related to a particular event.
- From the base map, users will be able to view device statuses, operate switches, turn on and off layers, and view configurable attributes of the facilities. The display can be filtered based on network components or devices related to a particular event.
- The InService UI will provide comprehensive dialog for SCADA Alarms, Crew Status, Pending Jobs, and Work Dispatched.
- The InService system will construct the DMS geospatial electric network model from data imported from the KCP&L GIS.

1.4.5.2 Outage Management System

1.4.5.2.1 OMS Overview

The OMS component of the DMS is provided by Intergraph for the SGDP. This component provides the ability to view the current connectivity of the distribution feeders and safely manage day-to-day and emergency restoration work. The OMS provides the basis for all outage information and is uniquely suited for KCP&L's needs, minimizing the integration costs with the existing GIS and Mobile Work Force Management systems. The OMS is integrated at a product level with the Siemens DNA and D-SCADA products to provide a complete solution with "best of breed" product functionality.

1.4.5.2.2 OMS Characteristics

Intergraph's InService model is built upon KCP&L's existing GIS with links to KCP&L's CIS. Intergraph's base OMS product is capable of analyzing outage notifications from CIS, integrated voice response (IVR), and the automated metering infrastructure. Using a configurable rules engine, these "calls" are grouped together to predict the correct protection device. Input from SCADA systems and manual input from an operator or dispatcher supplement these predictions.

The major benefits of Intergraph's OMS for KCP&L's implementation include:

- Increased network reliability by proactively monitoring the grid for potential problems using distribution analytics and alarming for notification.
- Reduced time to restore power by using the trouble analysis engine to pinpoint the most probable outage location

InService's trouble analysis uses the GIS network connectivity model as the baseline configuration, and then processes all transactions to maintain the real-time state of the distribution system. Trouble analysis handles the meter notifications to predict the extent of an outage and the most likely point of failure.

InService's switching procedure management (SPM) works with Siemens' DNA to handle emergency or planned switching orders. SPM will allow KCP&L dispatchers to create, review, and execute switch plans with multiple levels of approval.

1.4.5.3 Distribution Supervisory Control and Data Acquisition

1.4.5.3.1 D-SCADA Overview

The Distribution Supervisory Control and Data Acquisition system provides real-time device and automation information to keep the operating model as close as possible to the real conditions in the field. D-SCADA provides all real-time data services and control agent capabilities for the combined Siemens/Intergraph DMS solution.

1.4.5.3.2 D-SCADA Characteristics

The D-SCADA component of the DMS is provided by Siemens for the SGDP. D-SCADA provides interaction capabilities with automated and intelligent distribution system field devices. D-SCADA includes the following:

- Data Acquisition – provides the interface to the system field devices, facilitates the scanning of telemetered data periodically and by exception, transmits control commands, and ensures data integrity
- Network Control Executive – handles switching commands from the OMS and manages their execution

- ICCP Interface – provides the interface that connects D-SCADA to the OMS. It facilitates real-time data transmission and reception, as well as required data point identifier mapping and conversion
- Data Archiving Interface – directs scanned and derived system data to an independent long term archiving system (Siemens HIS)
- Communications Management Display – enables the user to view and change the status of the data acquisition equipment and also displays communications equipment errors and allow the user to view and reset communication error counts
- Configuration Management Tool – monitors the status of key components of the D-SCADA network servers, printers, network interfaces, true time devices, database domains, etc.; it also allows the user to start and stop D-SCADA on individual servers

1.4.5.4 First Responder Functions

One of the main objectives of the SmartDistribution subproject is to implement a family of automatic, distributed First Responder functionalities. These functionalities are provided by Siemens' Distribution Network Analyses (DNA), and they will be performed centrally by the DMS and locally by the DCADA system in the Midtown Substation. These applications, running on redundant systems, are enhancements to the basic substation automation system. The applications are configurable to their deployment location and the utility's needs.

1.4.5.4.1 First Responder Function Overview

As part of the project, KCP&L will implement distribution First Responder applications that greatly improve the control of the distribution network, increase supply quality and reliability, ensure optimal use of network equipment, and minimize losses and detection and elimination of overloads at particular points in time.

The First Responder functions are provided through Siemens' DNA. The DNA provides tools to simplify and improve the analysis of situations, providing more reliable network status information and supporting the network operation for both unplanned situations and planned activities. DNA uses the CIM-based logical and topological data model of the distribution network of the real-time database. This data model will be synchronized between the central DMS SCADA system and the substation DCADA system.

For this project, Distribution Network Analyses are composed of the following capabilities:

- Distribution System Power Flow
- Distribution System State Estimator
- Feeder Load Transfer
- Volt/VAR Control
- Fault Management

1.4.5.4.2 First Responder Function Characteristics

Each DMS and substation controller vendor has its own set of distribution applications, but for this project, KCP&L is utilizing Siemens' Distribution Network Analyses. The DNA provides equipment loading and complex voltage calculations to help the operators understand the voltage and loading of the distribution feeders and individual equipment at any point in time. It also provides a variety of Fault Management and Operations Optimization tools to offload the operations staff and improve efficiency. The DNA applications that are being configured for the SGDP are detailed below.

1.4.5.4.2.1 Distribution System Power Flow

Distribution System Power Flow (DSPF) calculates voltage magnitude and phase angle for all electrical nodes, active and reactive powers for slack nodes, and reactive power and voltage angles for nodes with PQ/PV generators. It calculates network status (voltage magnitudes and phase angles, line flows, and network losses) under different load conditions and configurations to detect any potential limit violations. The results of DSPF are used for further operational analysis and optimization processes. DSPF is capable of handling both symmetrical balanced and unsymmetrical unbalanced distribution systems. In the real-time context the DSPF can be executed based on a periodic, manual or event triggered conditions.

In DCADA substation operation, the DSPF combines the results of the Distribution System State Estimator and calculates the load flows and voltage conditions during the solution search. It operates in a closed loop mode in the substation.

1.4.5.4.2.2 Distribution System State Estimator

Distribution System State Estimator (DSSE) provides a complete network solution for real-time network conditions for real-time monitoring and further analysis of the network. This solution is based on real-time measured values, scheduled loads, and generations. It provides the statistical estimates of the most probable active and reactive power values of the loads using existing measured values, switching device statuses and initial information on active and reactive customer loads. DSSE results are used to monitor the real-time network operating state. In the real-time mode the DSSE can be executed periodically, manually or triggered by an event.

DSSE application provides the real time status of the electric node voltage vectors as a basis for power flow calculations and the starting point for other subsequent analysis functions (Volt/VAR Control (VVC), Feeder Load Transfer (FLT), and Fault Detection, Isolation and Restoration (FDIR)). DSSE is a closed loop function processing initial load values and minimizing the differences between the measured and calculated values. Upon obtaining the voltage vector solutions, it calculates the flows of active and reactive power on all lines as well as power losses.

1.4.5.4.2.3 Feeder Load Transfer

Feeder Load Transfer (FLT) determines the optimal radial distribution network configuration to mitigate or remove feeder overloads. It removes the feeder overloads by transferring load from overloaded feeders to the feeders with spare capacity. FLT determines switching plans that ensure continuous supply of power to the consumers, and voltage and current levels within technical limits. FLT can be triggered manually to transfer the load from one feeder to another or it can be triggered by DSSE.

FLT can be executed in closed loop, open loop or study mode in the DMS Control Center level and in closed loop mode in the substation level. The result of closed loop execution in both DMS and DCADA level is a set of the switching steps that will be performed on remotely controlled “normally open switches” as well as closed switches. The result of executing FLT in open loop mode in DMS level is a list of suggested switch operations that includes both remotely as well as manually controlled switching devices. The solutions presented by FLT will be verified by the DSPF to assure there are no remaining overloads or voltage violations. In the latter case, the FLT will trigger VVC functionality to try to find an optimal solution. In case a solution is not found or any of the switching steps is unsuccessful, a warning will be sent to the dispatcher in the DMS Control Center and the DCADA application part of functions will be disabled.

1.4.5.4.2.4 Volt/VAR Control

A Volt/VAR Control (VVC) function deals with the complexity of the voltage and reactive power control in a modern distribution system. The primary objective of VVC is to satisfy voltage and loading constraints. It is able to work with both balanced and unbalanced distribution systems. It supports the control of transformer on-load tap positions (LTC, voltage controllers) and switchable shunt reactive devices (typically capacitors) to meet the objectives. VVC can be executed to satisfy any of the following 4 objective functions:

- Minimize the sum of power losses
- Minimize the power demand
- Maximize the substation transformer reactive power
- Maximize the difference between energy sales and energy prime cost

1.4.5.4.2.5 Fault Management

Fault Management is a set of DNA applications used for locating distribution network faults and providing fault (or planned outage) isolation and service restoration. Fault Management can be executed in real-time or study context. Fault Management is capable of localizing the faulty area as closely as possible, based on available real-time data from SCADA. The Fault Management set of applications includes Fault Location, Fault Isolation and Service Restoration, Fault Isolation and Immediate Restoration, and Fault Detection and Immediate Restoration.

Fault Location (FLOC) determines the locations of permanent faults through the telemetered information protection devices and fault indicators as well as manually updated information. FLOC is triggered by change in the switch status. It can be operated in open and closed loop mode. Fault Location can be configured to handle either outage and/or non-outage faults. If different faults (independent from each other) trigger different fault detectors, FLOC detects and processes multiple faults in parallel.

Fault Isolation and Service Restoration (FISR) can be used for section isolation due to maintenance work or fault in the system. The isolation function determines a set of switching operations to isolate an area of the network. It can be initiated by the location of the faulty segment or area, or by manual selection for planned outage. Service restoration provides a possible choice of switching procedures to restore service. FISR can be executed in open loop or closed loop mode. In open loop mode, FISR presents the advisory solutions to the dispatcher and the dispatcher will make a final decision to execute the optimal solution. In closed loop mode, FISR executes the solution calculated. Only if the control step is not successful or not executable, further steps are stopped and a dispatcher is informed.

Fault Isolation and Immediate Restoration is performed to isolate equipment from the rest of the network and immediately restore unaffected and non-faulty de-energized equipment. In addition to switching operations required to isolate the specified equipment, additional switching operations required to energize (from alternate sources) equipment that is de-energized but not outaged are determined. If the selected equipment is energized, fault isolation and immediate restoration can be configured to generate restoration steps before isolation steps.

Fault Detection and Immediate Restoration (FDIR) is a combination of the FLOC and FISR features to locate the fault and isolate the faulted area and immediately restore power to unfaulted but out-of-service customers. FDIR is triggered by FLOC function. FDIR can be executed only in closed loop mode at both substation and DMS Control Center levels. It will select the most feasible isolation and restoration procedure and execute it by sending a control command to the field. This assures minimal outage time. In the event that it cannot find a local solution within its means, it will notify the dispatcher for higher level analysis and supervision.

1.4.5.5 Data Historian

1.4.5.5.1 HIS Overview

The Historical Information System (HIS) provides a reliable archive for storing historical data from PowerCC. It can also be used for doing data and event analyses.

1.4.5.5.2 HIS Characteristics

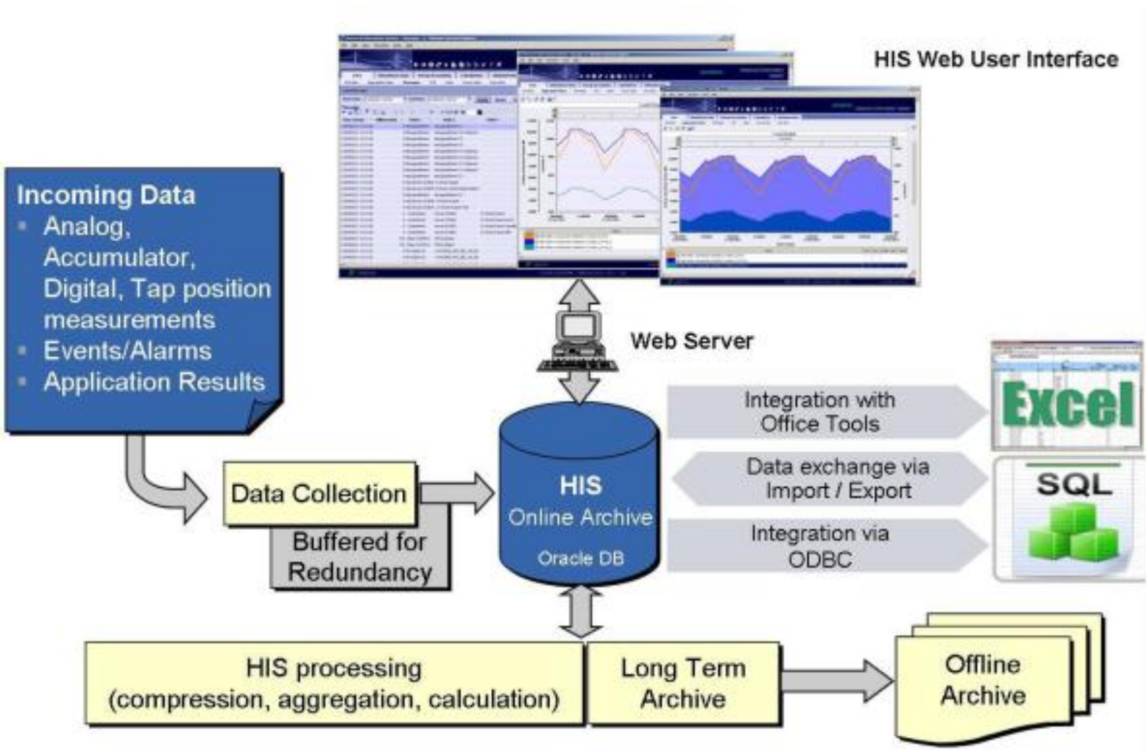
Siemens HIS is designed to store large quantities of real-time data from PowerCC. It archives this data securely, even during periods of system failures and huge data volumes. The storage can be stored periodically or non-periodically. The components of the HIS are shown in Figure 1-24 below.

For KCP&L's implementation, the HIS will collect and store analogs, digitals, accumulators, messages, and tap positions. The data is obtained from Siemens PowerCC, and it will be collected both periodically and spontaneously.

The HIS contains a graphical user interface for viewing the data. With this GUI, users can view raw data collected over a specified time range. They can also filter the data by a certain point or a specific event, and they can view a sequence of events for a set of data points over a specified time range.

The HIS web-based user interface follows the look and feel of PowerCC, and it allows the user to view the historical data in multiple formats. The tabular displays and charts can be defined by time range, and the user can filter and sort in a variety of ways to quickly focus on the data point of interest. The data can be printed straight from the HIS or exported to MS Word, MS Excel, CSV, or XML files.

Figure 1-24: HIS Components



The HIS has a calculation engine that can combine values from different data points, and it can perform two types of calculations:

- On-the-fly calculations (executed on-the-fly after they have been started in the UI)
- Persistent calculations (defined based on persistent aggregations)

1.4.5.6 Advanced Distribution Automation Field Area Network

The Advanced Distribution Automation (ADA) Field Area Network (FAN) exists to provide monitoring and control capabilities to devices outside of the substation. These devices communicate with both the substation controller and the distribution management system. The substation controller uses the field device information to perform First Responder functionalities in closed-loop mode, and the DMS uses the field device information to perform First Responder functionalities in either open or closed loop. The distribution operator will have access to all of the information about these field devices to assist in planning decisions and resolve network issues.

1.4.5.6.1 ADA FAN Overview

Originally, KCP&L planned to use the AMI network for both metering and distribution automation purposes. This would have reduced equipment, installation, and network management requirements. One of KCP&L's main project goals, however, was to utilize NIST's emerging standards for the smart grid and test out the interoperability between system vendors. For ADA, this meant using Internet Protocol (IP) to communicate to the field devices on the feeders. As a result, KCP&L opted to implement a separate field network for DA.

1.4.5.6.2 ADA FAN Characteristics

The KCP&L Advanced Distribution Automation network will consist of a number of field devices that communicate to the substation controller and to the DMS via an RF mesh network.

1.4.5.6.2.1 Tropos Network

Tropos' GridCom® wireless IP mesh network will extend the KCP&L SmartGrid IP network to reclosers, capacitors and fault indicators in the field, providing direct monitoring and control communications with substation-based distribution automation controllers and the centralized distribution management system. It will help KCP&L optimize energy delivery through active Volt/VAR optimization and feeder load transfers.

The Tropos GridCom® network also paves the way for enhancing power reliability by centrally monitoring fault indicators and automatically configuring around faults, reducing the impact and duration of outages, which is a cause of increasing concern for customers. The network provides the high-capacity, low-latency and security required to support the applications KCP&L plans to deploy to implement their advanced distribution automation vision for the SGDP.

The Tropos GridCom® network provides high resiliency with multiple redundant communications pathways to ensure that there is no single point of failure. It leverages the 2.4 GHz and 5.8 GHz frequency bands simultaneously and dynamically manages airtime, helping to avoid localized interference on any one frequency band. Dynamic channel selection, adaptive noise immunity and other advanced RF resource management techniques provide added resiliency.

GridCom® is based on a fully distributed architecture. It does not rely on a centralized controller for its operation, removing potential single-points-of-failure and eliminating unnecessary network traffic. GridCom's distributed intelligence performs functions such as network optimization, path selection and routing, and enforcing security and QoS policies.

GridCom® supports centralized management using Tropos Control, a comprehensive and scalable network management system. Tropos Control supports network implementation and optimization plus ongoing management of Key Performance Indicators. Although the network itself operates independently of Tropos Control, Tropos Control is used for alarm management, configuration, provisioning, and performance management.

1.4.5.6.2.2 Automated Field Devices

KCP&L is utilizing a combination of existing and new devices for this distribution automation deployment. The following devices are planned for installation in the SGDP area:

- Capacitor bank controllers - KCP&L already has a number of capacitor banks installed in the SGDP area, so these will be used on the new Tropos network. The old controllers will be replaced with new S&C IntelliCAP PLUS controllers, and a Tropos 1310 router will be connected to the controller. The capacitor bank controllers will communicate with the Tropos router via serial DNP3. Although KCP&L wanted IP communications to all of the controllers, this was not an option from most capacitor bank controller manufacturers. As a result, the communications from the SICAM to the router will be IP based, but the communications from the router to the controller itself will be serial. The capacitor banks used for this project are a combination of standard and VAR controls.
- Fault current indicators – KCP&L will be installing Horstmann Fault Current Indicators (FCIs) for the SGDP. Each FCI receiver can communicate with up to twelve FCIs, or four sets of three devices (one device per phase). The quantity of FCIs associated with a particular receiver is based on the number of devices desired in a certain geographic area – the range of the receivers is the limiting factor. KCP&L will only be able to get information *from* these devices; FCIs are not capable of responding to any controls.
- Recloser controllers - KCP&L plans to use two different types of reclosers for this distribution automation implementation – the G&W Viper-ST solid dielectric and the Siemens SDR 3212 vacuum reclosers. The recloser controllers are SEL 651R. All of the reclosers and their associated controls are new for this project. The reclosers are being used for three different purposes:
  - Isolation switch – used where the feeder transitions from underground to overhead
  - Mid-circuit recloser – used to segment the feeder into multiple pieces to limit the affected customers in the event of a fault
  - Tie recloser – used to feed a portion or all of a circuit from an adjacent circuit

1.4.6 SmartGeneration

KCP&L will implement a Distributed Energy Resource Management (DERM) system and make use of a variety of distributed energy resources in the project area, including:

- Grid-scale energy storage
- Distributed renewable generation
- Direct load control demand response programs

Working in concert with other SmartGrid technologies, the DERM and these resources will serve to demonstrate a "virtual power plant" which can dynamically respond to changing system conditions. The net effect of this virtual power plant is to defer the need to build additional fossil-fuel generating resources as well as helping to defer distribution and transmission system upgrades. Benefits of such deferrals flow through to customers in the form of lower costs, increased reliability and reduced environmental impact.

1.4.6.1 Distributed Energy Resources Management

The DERM system stores and manages all information pertaining to DR and DER programs and assets. The DERM must integrate with a number of other KCP&L systems, including the CIS, MDM, and DMS. In addition to interfacing with these back office systems, the DERM will communicate with various "control authorities" that oversee particular types of resources.

For this project, the DERM will be used to respond to overload conditions for system reliability purposes. The DERM will help to prevent overloads from occurring, and it will shorten the duration of outages that do occur. The DERM is also capable of being used for economic purposes, but this will not be the focus during the SGDP.

1.4.6.1.1 DERM Overview

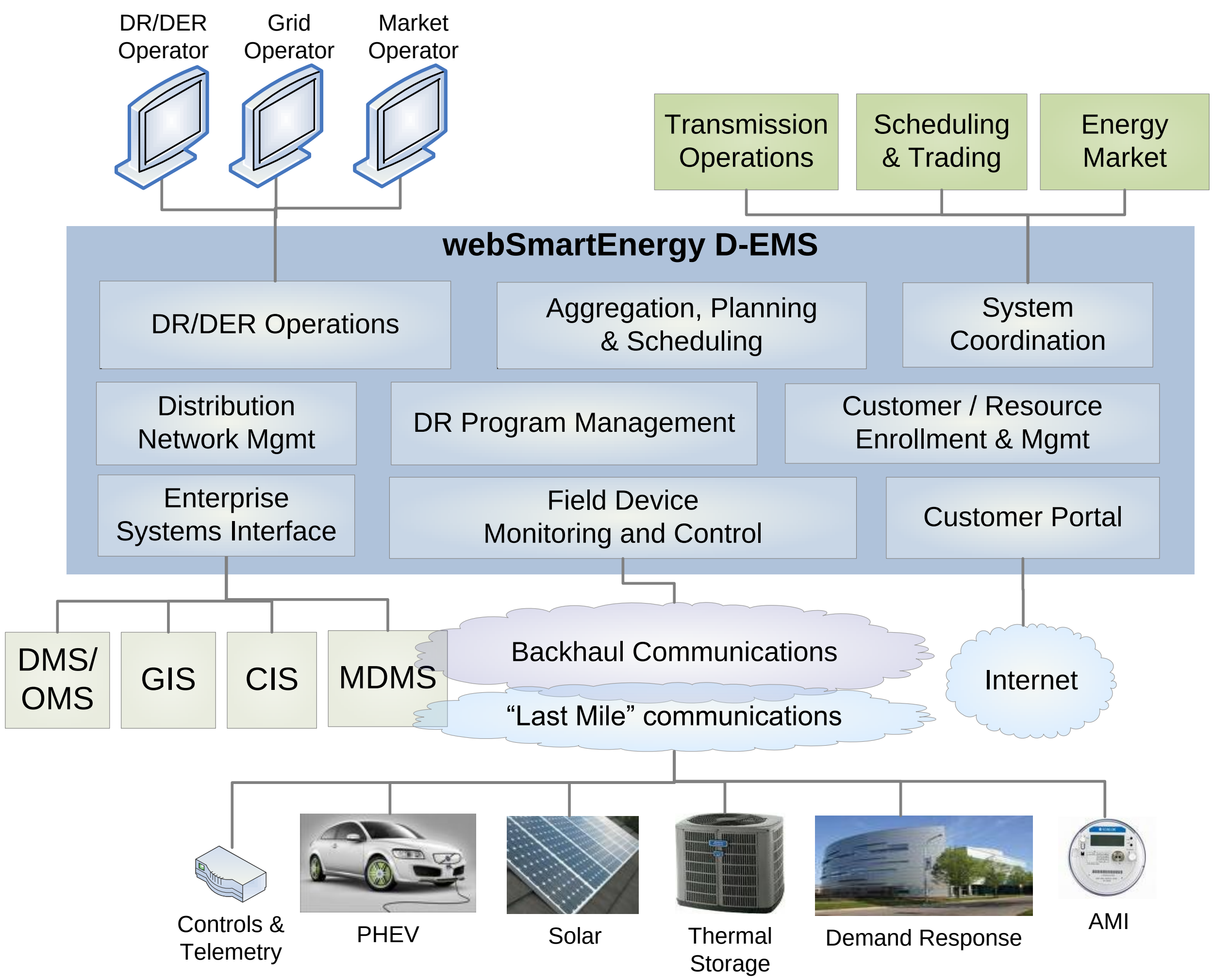
For the SGDP, KCP&L will be implementing a DERM system from Open Access Technology International, Inc. (OATI). Their product, called the webSmartEnergy Distributed Energy Management Solution provides full visibility into demand side capabilities, the ability to leverage those capabilities for operational and economic efficiencies, and the ability to aggregate and use those capabilities in support of wholesale market operations. A diagram of the webSmartEnergy Distributed Energy Management Solution appears in Figure 1-25.

1.4.6.1.2 DERM Characteristics

The DERM system provides the bridge between advanced metering, DR/DER, variable generation, distribution grid, transmission grid, and wholesale markets. In addition to a full complement of conventional Demand Response capability, the DERM provides the capabilities needed to optimally manage distributed energy resources for the support of distribution system load relief, and for the transmission and market operations, (e.g., providing ancillary services and balancing energy to support variable generation). By mapping DR/DER to distribution grid locations, and tracking circuit, feeder, and equipment conditions, the DERM provides a unique combination of capabilities for integrated smart grid operation while considering limitations imposed by transmission and distribution grids.

For the SGDP, the DERM will be called upon when the DMS needs assistance with a current or projected future overload. The DMS will try to solve the issue using its own resources first, through feeder load transfer or conservation voltage reduction. If these methods do not completely address the overload, then the DMS will call upon the DERM for demand response.

Figure 1-25: Distributed Energy Management Solution Functional Overview



The DERM will store and manage all the information about the various demand response programs and assets for the SGDP. It will keep track of tariff limitations (for example, KCP&L might only be able to call upon a particular program four times in one month) and any costs associated with calling on each program. It will suggest DR options that address the overloaded feeders and it will prioritize based on these limitations and associated costs.

Once the operator selects the DR to apply to the situation (either using the DERM's recommendation or selecting other options), the DERM schedules the DR event. The DERM won't communicate directly to the end devices participating in the event, however. Instead, the DERM sends DR messages to the "control authorities." For the SGDP, the DERM will dispatch DR events to the following control authorities:

- HEMP for residential DR
- VCMS for EV charging stations
- DMS for grid-connected assets, such as the 1MW battery

These control authorities will then send the appropriate DR messages down to the end devices to direct their participation in the scheduled event. These DR interfaces and events are described in additional detail in Section 2.2.5.2, Demand Response Load Curtailment.

1.4.6.2 DR Load Curtailment Programs

1.4.6.2.1 DR Load Curtailment Program Overview

As part of the SGDP, KCP&L will deploy direct load control devices to customers and businesses within the project area and integrate them with back office applications to manage and execute market-driven or reliability-driven demand response events. Direct load control devices will include:

- Residential stand-alone PCTs
- Residential HAN based PCTs
- Residential HAN based LCSs

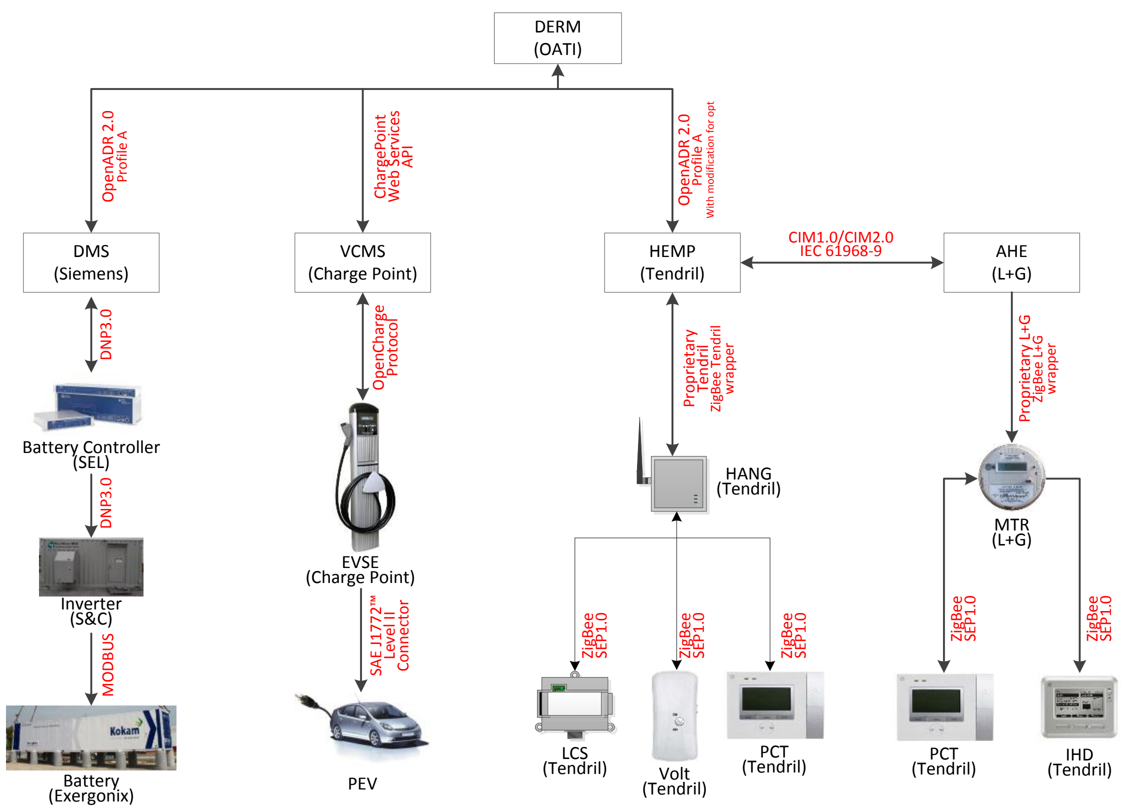
All demand response resources will be engaged through two-way communication between the customer premise and the back office DERM webSmartEnergy application. The DR devices may be aggregated and operated based on grid connectivity (small- or wide-scale) as needed to provide desired locational load relief. The project will assess these DR resources' capabilities for providing emergency "fast DR" and planned DR for day-ahead and hour-ahead grid study case scenarios.

In addition to these residential devices, KCP&L will also utilize the Vehicle Charge Management System for demand response contributions from the ten charge stations associated with the SGDP. Lastly, the DERM will be able to utilize the grid-connected battery for DR load curtailment.

1.4.6.2.2 DR Load Curtailment Characteristics

Figure 1-26 shows the various systems that the DERM can call upon, along with the message types used for each of the associated interfaces.

Figure 1-26: Demand Response Load Curtailment Architecture



1.4.6.2.2.1 Residential Stand-alone Programmable Communicating Thermostat

The Stand-alone PCT is an electronic device that receives information directly from a customer SmartMeter wirelessly via an IEEE 802.15.4 network running the ZigBee SEP 1.0 specification to receive demand response events, pricing signals, and text messages.

Similar to an existing enterprisewide program called Energy Optimizer, KCP&L will deploy advanced PCTs to customers in the project zone with SmartMeters in the SGDP area. These ZigBee-based PCTs will be paired with customers' SmartMeters to enable utility-controlled demand response events. Events will be initiated by the DERM and event messages will be delivered to the devices by the AMI network (via the SmartMeter).

When a demand response event occurs, customers are notified ahead of time with information about event start time and duration. By default, customers are opted into each event. However, once customers receive the event, they can opt-out or back in at any time before the event concludes. Event participation is recorded for post-event evaluation and analytics.

1.4.6.2.2.2 Residential HAN DR

Similar to the stand-alone PCT, KCP&L will deploy HAN PCTs and LCSs as a part of a larger HAN package that includes a HAN gateway, PCT, and two 120 volt control switches. The PCT is identical to the stand-alone PCT. However, the HAN gateway facilitates two-way communications with utility back office systems over broadband internet connection rather than the AMI network.

1.4.6.2.2.3 Battery Energy Storage System

The Battery Energy Storage System (BESS) will be used for a number of stand-alone applications during the SGDP, but it will also be used as a resource for demand response purposes. During peak periods of energy use, KCP&L can call on the battery via the DERM and discharge the battery for grid relief.

1.4.6.2.2.4 Vehicle Charge Management System

The VCMS is the control system for the ten Electric Vehicle Charge Stations (EVCS) that will be deployed within the SGDP area. These stations will be integrated with the DERM and available for use during demand response events. Although they will only provide DR relief if vehicles were using the stations during the time of the event, this interface will still provide a valuable test field.

1.4.6.3 Battery Energy Storage System

1.4.6.3.1 BESS Overview

One SmartGeneration component of the SGDP is the evaluation of a 1.0 MW/1.0 MWh Exergonix lithium polymer battery energy storage system. This system will be interconnected to the head of a single urban circuit just downstream of the substation bus. It will be integrated with demonstration control systems and will be exercised to demonstrate its capability to offer direct grid support via the following applications:

- Energy time shifting
- Net circuit load peak shaving
- Volt/VAR support
- Circuit Islanding

In addition to demonstrating these applications, KCP&L aims to appraise the battery system's technical performance with regards to roundtrip AC efficiency.

1.4.6.3.2 BESS Characteristics

KCP&L partnered with Exergonix (www.exergonix.com) to provide and install the BESS. The Exergonix BESS consists of over 5,000 Kokam Superior Lithium Polymer Battery (SLPB) pouch cells that are coordinated by a unique battery management system. The battery system is driven by a PureWave Storage Management System (SMS) from S&C Electric (this may also be referred to as the Power Conditioning System (PCS)).

1.4.6.3.2.1 Battery Technology

The patented SLPB technology is proven, is already in production in the U.S., and is being used in numerous applications around the world. The SLPB cell design increases energy density to as high as 200 Wh/Kg in high energy cell configurations and power densities as high as 2400 W/Kg can be achieved with minimum optimization on a high power cell design. The Kokam SLPB meets all performance standards of the U.S. Advanced Battery Consortium (USABC). The SLPB cells are expected to provide extended run time, 10+ years of operational life (up to 10,000 cycles), reduced need for complex cooling systems, and safe operation over a wide range of temperatures.

Figure 1-27: Grid-Connected Battery

1.4.6.3.2.2 Power Conditioning System

The S&C Electric PureWave SMS manages charge and discharge of the battery subsystem and converts AC grid power to DC battery power. It consists of a control system and a four quadrant bi-directional inverter, rated at ±1.0 MW/1.25 MVA. The SMS converts nominal battery voltages (460 V_{DC} – 800 V_{DC}) into 3-phase 60 Hz, 480 V_{AC}, ±10%. It can operate at temperatures between -40°C and +40°C and altitudes up to 1,000 meters without de-rating. It is connected to a 480 V_{AC} transformer via a wye-delta configuration to step-up voltage to a 13.2-kV MV distribution circuit. This PureWave SMS is specially equipped with remote control protocols for islanding purposes, a feature that is not included in the standard commercial product offering. The 800 V DC-to-DC converter can step down voltage and utilize a UPS to provide 30-minutes of backup auxiliary power to all internal controls needed during islanding events. At the conclusion of islanding events, the SMS can sync the battery with a recloser to automate seamless grid reconnect.

1.4.6.4 Distributed Renewable Generation: Solar Photovoltaic

1.4.6.4.1 Solar PV Overview

KCP&L will install approximately 180 kW of diverse solar photovoltaic (PV) systems on both residential and commercial properties throughout the pilot project area.

The implementation of these PV systems within the pilot project area will enable KCP&L to assess:

- The impacts of intermittent distributed generation on circuit voltage and power quality
- Monitoring of renewable generation and tracking against RPS requirements
- Building a database of PV type/installation generation performance in the KC metro area
- The potential for reverse power flows due to distributed generation
- The feasibility of aggregating, managing and potentially dispatching a high penetration of utility owned distributed PV systems and capacity
- The feasibility of owning and operating numerous distributed generation on the system

1.4.6.4.2 Solar PV Characteristics

The PV systems, with the exception of those installed on utility property, will be established through a lease agreement in which KCP&L will lease rooftop space but will own and maintain the PV system for a multi-year contract period.

Each system will be designed and specified independently based on available southern facing roof space. A variety of PV technologies and installation methods will be sought. Each system will be directly grid connected and metered independently for tracking purposes.

Figure 1-28: Paseo High School Rooftop Solar PV System

1.4.6.5 Vehicle Charge Management System

1.4.6.5.1 VCMS Overview

The VCMS is deploying an integrated network of electric vehicle charging stations for the SGDP. A total of ten Electric Vehicle Charging Stations (EVCSs) will be deployed within the SGDP area. The VCMS and EVCSs will provide customers the convenience of public charging, while also providing KCP&L with further demand response resources and capabilities. The VCMS will be integrated with the DERM and will serve as the "control authority" for each EVCS during demand response events.

1.4.6.5.2 VCMS Characteristics

The VCMS and EVCSs for the SGDP are being supplied by LilyPad EV, a Kansas City-based licensed ChargePoint supplier. Each EVCS consists of a dual port, level 2 (240V) Coulomb CT2021 Charging Station with SAE J1772 standard connectors (Figure 1-29). Each EVCS is equipped with a cellular modem enabling two-way communications with the ChargePoint web platform. This will allow customers to locate and reserve individual EVCS using web mapping applications. Also, KCP&L will be able to monitor and manage each EVCS via the ChargePoint web platform.

Figure 1-29: Coulomb CT2021 Charging Station

Station summaries, including usage and inventory reports, reservation schedules, and audit reports, will be readily available through the platform. KCP&L will also be able to manage access control, station provisioning, station alarms, and peak load configurations.

As part of the SGDP interoperability efforts, KCP&L is implementing demand response integration between the VCMS and the DERM using APIs developed by ChargePoint. To help meet the SGDP cyber security goals, HTTPS and SSL protocols will be utilized for all API transactions between the VCMS and DERM. These APIs support the project goals of implementing cutting-edge industry interoperability standards. These APIs are capable of providing DERM (or other systems) with EVCS information, scheduling and reservation capabilities, demand management, and usage analysis. Utilizing this integration, the DERM will be able to execute demand response events on the VCMS and EVCS. Events can be performed on the entire population of EVCSs on an emergency or scheduled basis.

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2 TECHNICAL APPROACH [6]

The KCP&L SmartGrid Demonstration has been explicitly designed to be a complete end-to-end SmartGrid demonstration program in a geographically defined area of Kansas City. By focusing on the circuits and distribution feeders surrounding its Midtown Substation, the Company will be able to assess the potential benefits of a SmartGrid solution from SmartGeneration through to SmartEnd-Use in a regionally unique, controlled "laboratory" environment. The goals of this demonstration are in sync with those of the DOE Smart Grid Demonstration Initiative – to quantify smart grid costs, benefits and cost-effectiveness as well as verify smart grid technology viability, and validate new smart grid business models, at a scale that can be readily adapted and replicated around the country.

2.1 CROSS-CUTTING PLANS & IMPLEMENTATIONS

During Phase 1 of the SGDP the KCP&L project team developed and published a series of cross-cutting project plans that include:

- SmartGrid Interoperability Plan
- SmartGrid Cyber Security Plan
- Education & Outreach Plan
- Metrics & Benefits Reporting Plan

The following subsections provide an overview of the significant elements of each of these plans.

2.1.1 Interoperability Strategy & Plan [7]

The KCP&L project team developed and published a "SmartGrid Interoperability Plan" that detailed a strategy and approach for system interoperability for the KCP&L SGDP. The following subsections provide an overview of the significant elements of the Interoperability plan developed for the project.

2.1.1.1 Interoperability Vision

Federal and industry requirements for interoperability and security are critical to a successful integrated smart grid solution and they are a key focal point for this project. Inherent in any approach to integration and interoperability are the challenges posed by the heterogeneous nature of the grid components; as each component varies in ability to securely and accurately communicate in the overall smart grid solution.

KCP&L's vision calls for many emerging technologies to be integrated into the Transmission and Distribution networks, ultimately, achieving interoperability with and between legacy environments. The planned SGDP poses challenges due to immature and emerging smart grid standards, the high level of interoperability involved across distributed platforms, and the need to carefully protect customer and system control information across a highly distributed network reaching outside of utility boundaries and onto customer premises. Given the heterogeneous nature of combining legacy components and products of numerous vendors, the project must anticipate and mitigate several challenges.

These challenges include:

- Communicating with legacy systems and devices
- Communicating between open standard and proprietary components
- Identifying failure and upgrading and maintaining components so that overall system operation is highly reliable
- Supporting interacting parties' anticipated response to failure scenarios, particularly loss of communications

2.1.1.2 Interoperability Strategy

To make effective progress for this project and deliver customer and operational benefits, KCP&L envisions an approach to maximizing interoperability that takes aggressive action despite market and standards uncertainties, and that provides a measured means to carefully protect operational reliability, cyber security, and long-term investments. The structured, evolutionary approach described in this document preserves investments, yet provides the flexibility needed for orderly integration of emerging frameworks, methods and standards. Key aspects of KCP&L's strategy for managing interoperability risks include:

- Product selection with consideration of emerging standards for distribution grid management (e.g., IEC 61968 and IEC 61850)
- Open and modular architectural approaches that emphasize vendor-independent integration mechanisms (e.g., Service-Oriented Architecture)
- Investment in ongoing integration test-bed capability to provide for agile component integration, interoperability testing and means for managing technical and security risks through hands-on application and integration of new technologies
- Continued collaboration with public/private industry consortia and special interest groups (such as SGIP, EPRI, IEC, IEEE, UCAIug and the GridWise Alliance) toward the refinement of interoperability standards
- Ongoing and regular review of current implementation and architecture versus current industry standards and emerging integration models

However, using a standard, even an open standard, is not a panacea. As technology changes over time, standards go through life cycle phases, both in commercial adoption and technical maturity. Today's new standard is tomorrow's legacy specification. Also, there is no shortage of standards within the complicated landscape of interface specifications in electric power, manufacturing, buildings automation, and information technology in general.

Throughout the project development life cycle, KCP&L will identify, analyze, and develop mitigation approaches to the various risks encountered in the project. This will be accomplished through periodic reviews, implemented to ensure the successful completion of one stage of the project's life cycle prior to progressing to a subsequent stage. During these reviews, adherence to standards, buy-in from stakeholders and resolution of issues will be accomplished. Evidence of completion will be accomplished through documentation of required artifacts for each life cycle stage.

2.1.1.2.1 Strategic Interoperability Directions

This section describes important strategic directions of KCP&L that are intended to enable increased interoperability. These technologies and the accompanying business processes will be implemented as needed for the SGDP; however, they represent important steps towards a broader integration of the demonstration systems.

2.1.1.2.1.1 Application Interface Interoperability

Initially, integration with legacy production systems will be achieved primarily through file transfers. However, ultimately, web services deployed in a Service-Oriented Architecture will be used to achieve interoperability between proprietary protocols and will be used to create open interfaces between legacy and new systems and applications. Through the use of open standards, such as web services and the protocols and standards defined by W3C and OASIS consortia, along with mechanisms for guaranteed delivery of transactions and resilient network architecture, KCP&L will deploy a smart grid ecosystem (system of systems) that is highly available, easily upgraded, interoperable, and that is capable of maintaining transactional integrity despite losses of communication between system components.

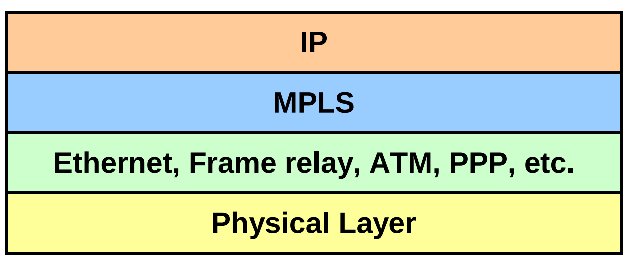
Web services are a set of emerging standards that enable interoperable integration between heterogeneous IT processes and systems. Web services provide a common standard mechanism for interoperable integration among disparate systems, and the key to their utility is their standardization. This common mechanism for delivering a "service" makes them ideal for implementing a Service-Oriented Architecture (SOA).

Besides using the common Web transports, Web services also require a common language for the data exchanged – Extensible Markup Language (XML). XML is simply the “scaffolding” for the actual exchange. For the Web services protocols to be interoperable across diverse systems and suitable for smart grid applications, standards bodies, such as W3C, OASIS, and WS-I must formally standardize these protocols. KCP&L continues to implement these standards and contribute to the SOA standards adoption process with other utilities through participation in user groups and standards bodies.

2.1.1.2.1.2 Interoperability of Communications Networks

With respect to the underlying communications network, KCP&L is implementing increasingly meshed approaches with redundant communications paths and traffic prioritization features (Figure 2-1). In part, this is being accomplished through adoption of Multi-Protocol Label Switching (MPLS) as specified by the Internet Engineering Task Force (IETF).

Figure 2-1: KCP&L MPLS-based IP Communication



MPLS is a highly scalable and protocol agnostic data-carrying mechanism that can encapsulate legacy routing protocols. MPLS offers enhanced security and robust communication failover capabilities. In addition, the protocol allows segmentation, prioritization and optimization of specific traffic, such as control and market information.

2.1.1.3 SmartGrid Demonstration Communication Networks

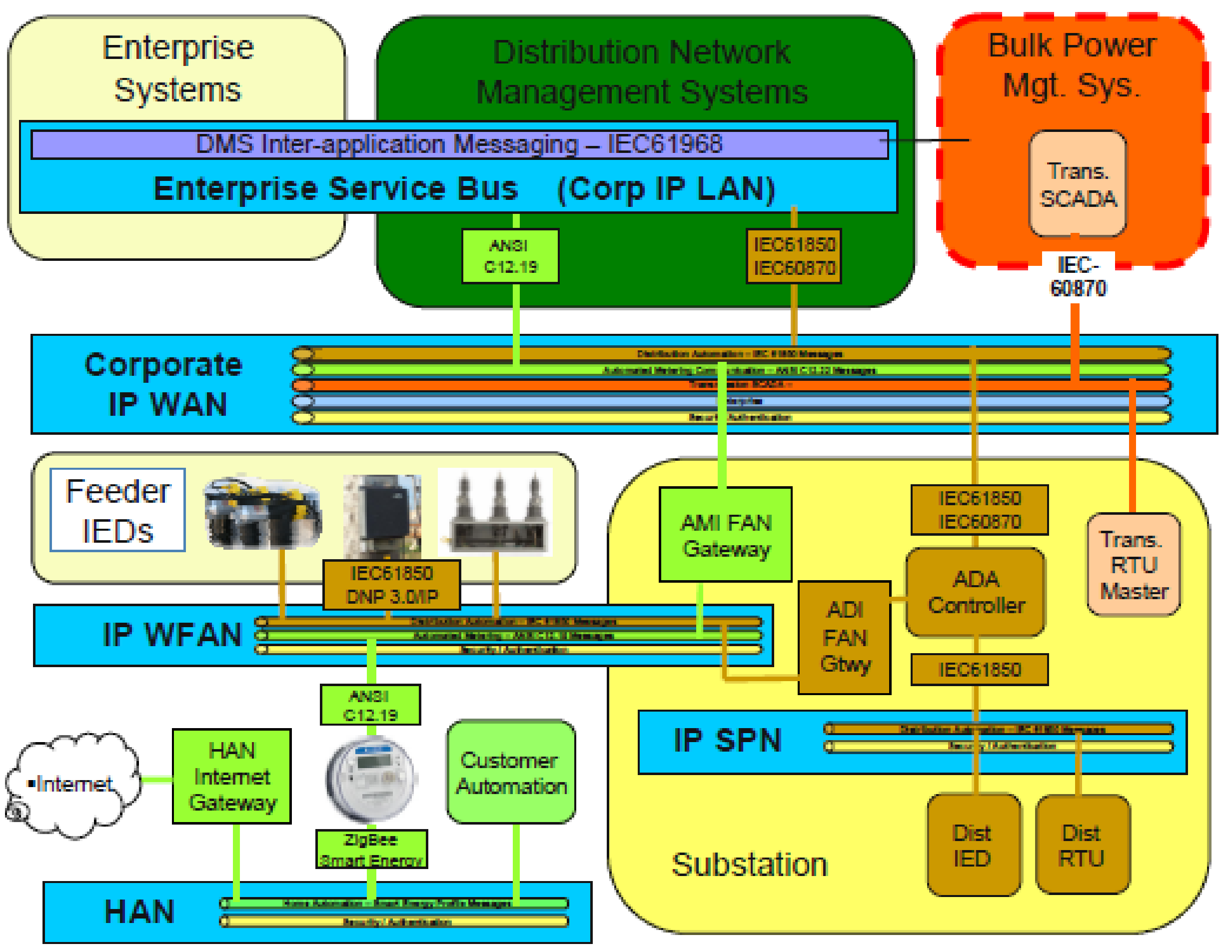
The public Internet is a very powerful, all-pervasive medium. It can provide very inexpensive means to exchange information with a variety of other entities. The Internet is being used by some utilities for exchanging sensitive market information, retrieving power system data, and even issuing some control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

KCP&L has chosen to implement its SGDP using private communications media wherever practical. By using the corporate IT WAN and a utility-owned FAN, the KCP&L SmartGrid pilot solution 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 risks. The communications and information networks proposed to support the deployment of the SGDP are depicted in Figure 2-2.

The far reaching and complex nature of the smart grid dictates that no single communications technology or security policy can be developed to implement and properly secure the smart grid. The hierarchical nature of the technologies that will be implemented to create the SmartGrid Communication Network provides for 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 set of security requirements and risk assessments. For example, within the bulk power system there are two distinct Security Domains: NERC-CIP and non NERC-CIP. 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.

Figure 2-2: KCP&L SmartGrid Demonstration Project Communication Network

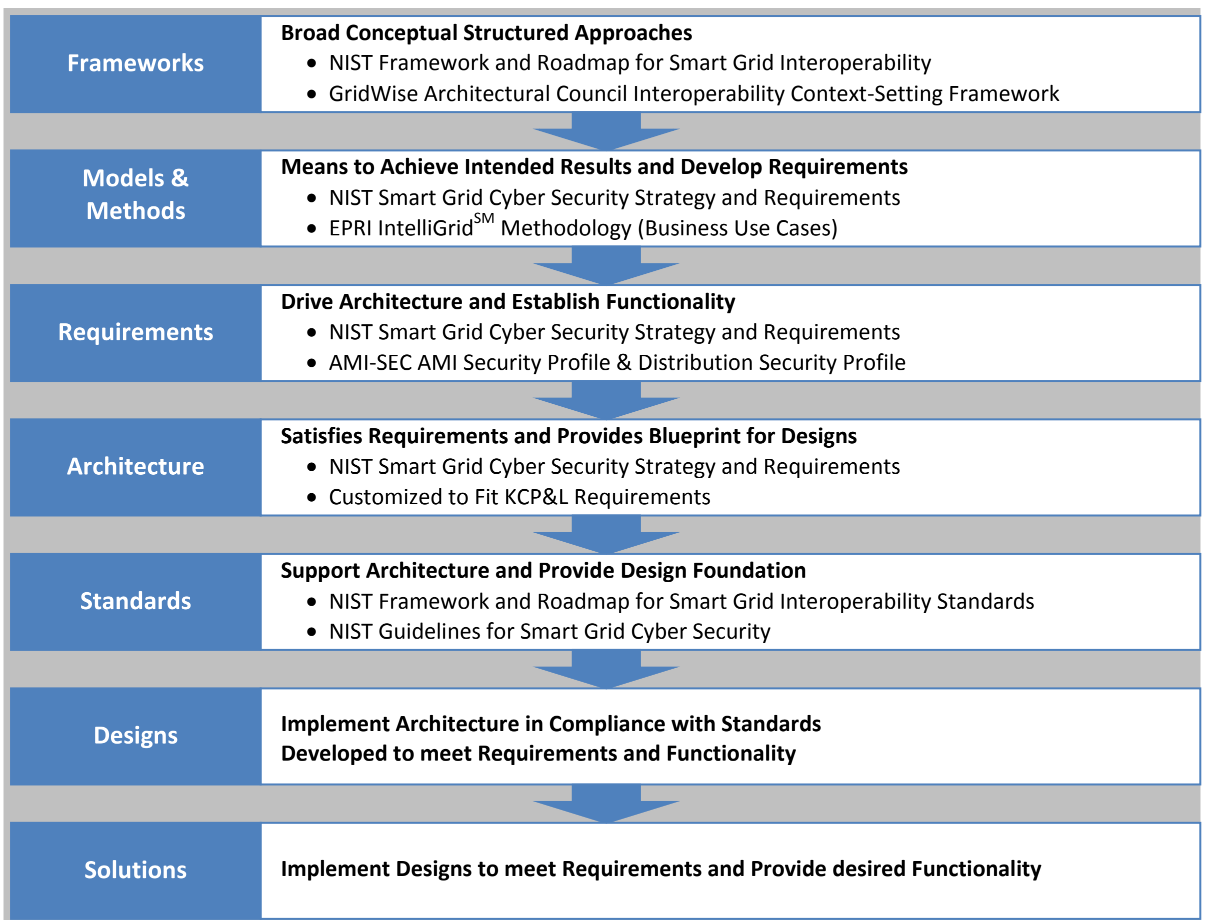


2.1.1.4 Interoperability Plan and Approach

To meet the interoperability challenges associated with ensuring interoperability across the SGDP, KCP&L will use a structured approach as outlined in Figure 2-3. This involves adoption of industry frameworks for interoperability from the GridWise Alliance, the National Institute of Standards and Technology (NIST) and the International Electrotechnical Commission (IEC).

The frameworks, and their associated models and methods will be used to derive architectures that satisfy requirements for interoperability. The architectures will be implemented as blueprints for designs. These components together comprise the KCP&L solution for smart grid and, when applied throughout the system life-cycle will ensure that the solution meets KCP&L's business requirements, achieves intended legal and regulatory objectives, operates securely and efficiently, enables reliability and agility, and can be easily integrated within the larger electric grid.

Figure 2-3: KCP&L SmartGrid Interoperability Approach



2.1.1.4.1 Frameworks

A solution framework captures key domains and their interactions in order to enable discussions between partners as to how their contributions address the overall solution. It is used to communicate within the electricity system to compare, align, and harmonize solutions and processes as well as with the management of other critical infrastructure. With the support of the context-setting framework, opportunities and hindrances to interoperability can be debated and prioritized for resolution. Cross-cutting issues, such as cyber security and privacy, are areas that need to be addressed in all aspects of the model and agreed upon to achieve interoperation. They usually are relevant to more than one interoperability category of the framework. The framework makes no architectural or technical recommendations. However, architectures will be derived from the framework and designs developed based on the architectural blueprints.

2.1.1.4.1.1 NIST SmartGrid Framework [8]

This KCP&L solution framework will be aligned with the NIST Special Publication 1108R2 - NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 2. This document identifies guiding principles for the adoption of standards for the smart grid and the smart grid domains to which interfaces and standards apply. It also identifies standards for consideration and incorporation into smart grid architectures and solution designs. Applicable standards will be incorporated into the KCP&L SGDP.

The smart grid is a complex system of systems for which a common understanding of its major building blocks and how they interrelate must be broadly shared. NIST has developed a conceptual model to facilitate this shared view. This model provides a means to analyze Use Cases, identify interfaces for which interoperability standards are needed, and facilitate development of a cyber security strategy. For this purpose, NIST adopted a model that divides the smart grid into seven domains (described in Table 2-1 and shown in Figure 2-4).

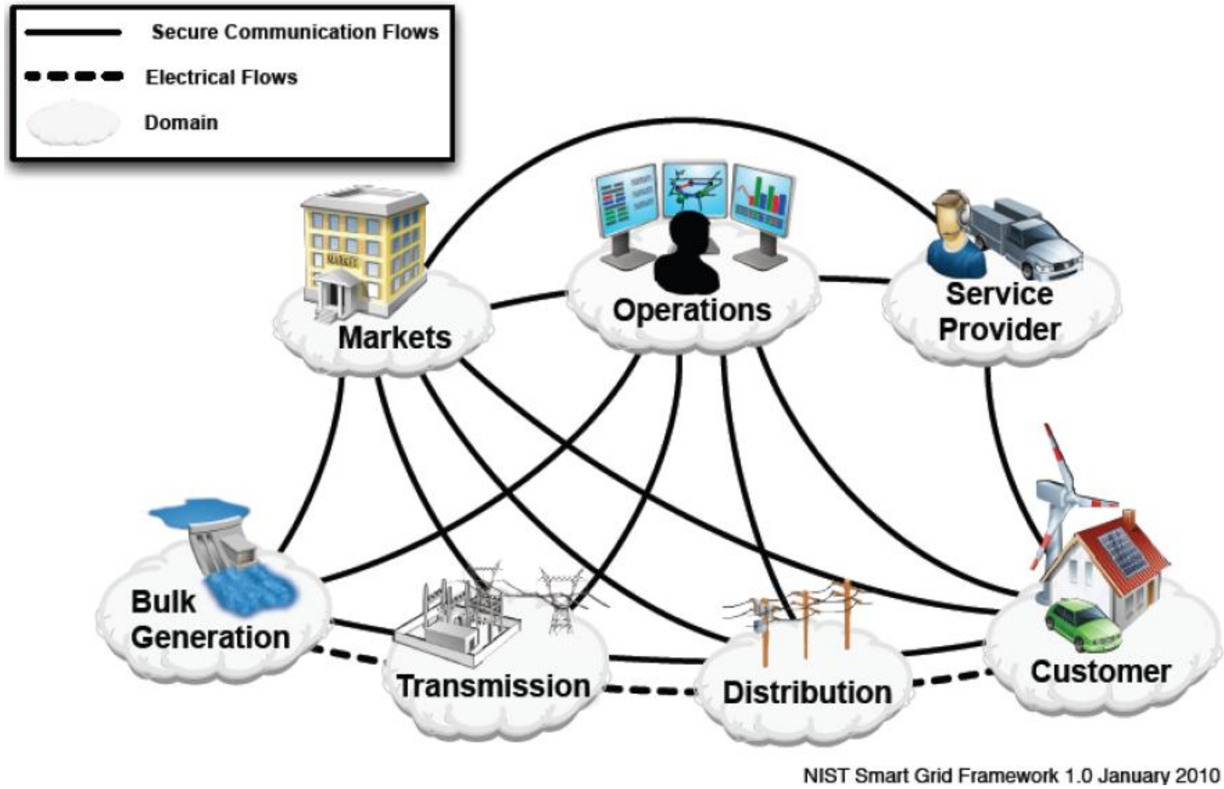
Each domain—and its sub-domains—encompass smart grid actors and applications. Actors include devices, systems, or programs that make decisions and exchange information necessary for performing applications: smart meters, solar generators, and control systems represent examples of devices and systems. Applications, on the other hand, are tasks performed by one or more actors within a domain. For example, corresponding applications may be home automation, solar energy generation and energy storage, and energy management. The *NIST Framework and Roadmap for Smart Grid Interoperability Standards* describes the seven smart grid domains in more detail.

Table 2-1: Domains & Actors in the Smart Grid Conceptual Model

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

In general, actors in the same domain have similar objectives. In order to enable smart grid functionality, the actors in a particular domain often interact with actors in other domains, as shown in Figure 2-4. However, communications within the same domain may not necessarily have similar characteristics and requirements. Moreover, particular domains also may contain components of other domains. For instance, the ten Independent System Operators and Regional Transmission Organizations (ISOs/RTOs) in North America have actors in both the Markets and Operations domains. Similarly, a distribution utility is not entirely contained within the Distribution domain—it is likely to contain actors in the Operations domain, such as a distribution management system, and in the Customer domain, such as meters.

Figure 2-4: Interaction of Actors in Different Smart Grid Domains



Underlying the conceptual model is a legal and regulatory framework that includes policies and requirements that apply to various actors and applications and to their interactions. Regulations, adopted by the Federal Energy Regulatory Commission at the federal level and by public utility commissions at the state and local levels, govern many aspects of the smart grid.

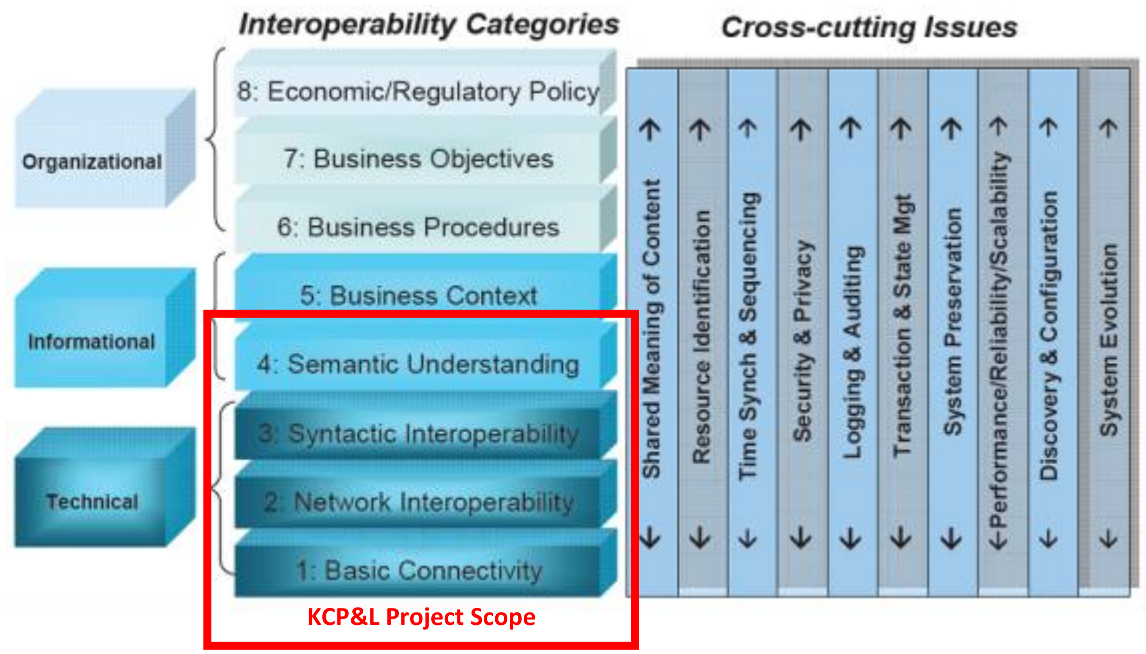
2.1.1.4.1.2 GridWise Architecture Council Interoperability Framework [9]

KCP&L will utilize the GridWise Architecture Council's (GWAC) Interoperability Context-Setting Framework to align the solution, make appropriate interoperability decisions, and deliver the anticipated results to the stakeholder community.

The GridWise interoperability context-setting framework identifies eight interoperability categories that are relevant to the mission of systems integration and interoperation in the electrical end-use, generation, transmission, and distribution industries. The major aspects for discussing interoperability fall into three categories: technical, informational, and organizational. The organizational categories emphasize the pragmatic aspects of interoperation. They represent the policy and business drivers for interactions. The informational categories emphasize the semantic aspects of interoperation. They focus on what information is being exchanged and its meaning. The technical categories emphasize the syntax or format of the information. They focus on how information is represented within a message exchange and on the communication medium.

Figure 2-5 depicts these categories of interoperability. The framework pertains to an electricity plus information infrastructure. At the organizational layers, the pragmatic drivers revolve around the management of electricity. At the technical layers, the communications network and syntax issues are information technology oriented. In the middle, information technology is transformed into knowledge that supports the organization aspects of the electricity-related business. The material in the *GridWise Interoperability Context-Setting Framework* describes each subcategory. Each layer typically depends upon, and is enabled by, the layer below it. The KCP&L SGDP will focus on the four (4) lower layers of the GWAC Stack as anchor points for the interoperability testing and demonstration.

Figure 2-5: GridWise Interoperability Framework



2.1.1.4.2 Methods and Models

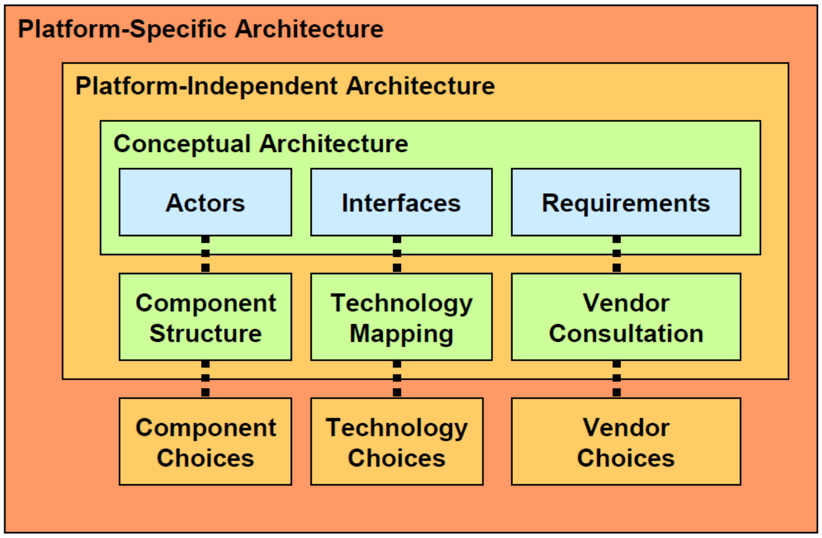
As a member of EPRI's five-year Smart Grid Demonstration Program, KCP&L's system integration and interoperability requirements definition and design will also be coordinated through EPRI's formalized Smart Grid Demonstration Program. The SGDP project team will leverage EPRI's IntelliGrid℠ methodology to support the technical foundation for a smart power grid that links electricity with communications and computer control. The IntelliGrid℠ Architecture is an open-standard, requirements-based approach for integrating data networks and equipment that enables interoperability between products and systems.

2.1.1.4.2.1 EPRI IntelliGrid℠ Methodology [10]

EPRI's IntelliGrid℠ methodology provides tools and recommendations for standards and technologies when implementing systems such as advanced metering, distribution automation, and demand response and also provides an independent, unbiased approach for testing technologies and vendor products. The IntelliGrid℠ methodology was developed at EPRI over a six year period and turned over to the International Electrotechnical Commission (IEC). EPRI has applied this methodology to help a number of utilities (FirstEnergy, Salt River Project, Alliant Energy, Duke Energy, Southern Company, and TVA) with specific roadmaps for smart grid development and deployment in addition to working with industry members of the IntelliGrid℠ research program to continually advance the interoperability standards and methods for the industry.

The IntelliGrid℠ methodology starts with a conceptual architecture and then moves to development of a platform-independent architecture that provides a basis for integrating actual applications. The ultimate goal is architecture with vendor specific aspects with the ability to plug-in many different vendor applications as a result of industry standard interfaces. Legacy systems and technology is integrated via appropriate gateways and translators. Figure 2-6 illustrates the concept of designing an architecture that starts with a conceptual architecture and then moves to development of a platform-independent architecture that provides a basis for integrating actual applications. The requirements developed in this project help provide the basis for the architecture design. For instance, the architecture should support new technologies like substation video and infrared camera data.

Figure 2-6: IntelliGrid^{SM} Architecture Definition Evolution



IntelliGrid^{SM} methodology defines an Environment as a logical grouping of power system requirements that could be addressed by a similar set of distributed computing technologies. Within 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 management requirements

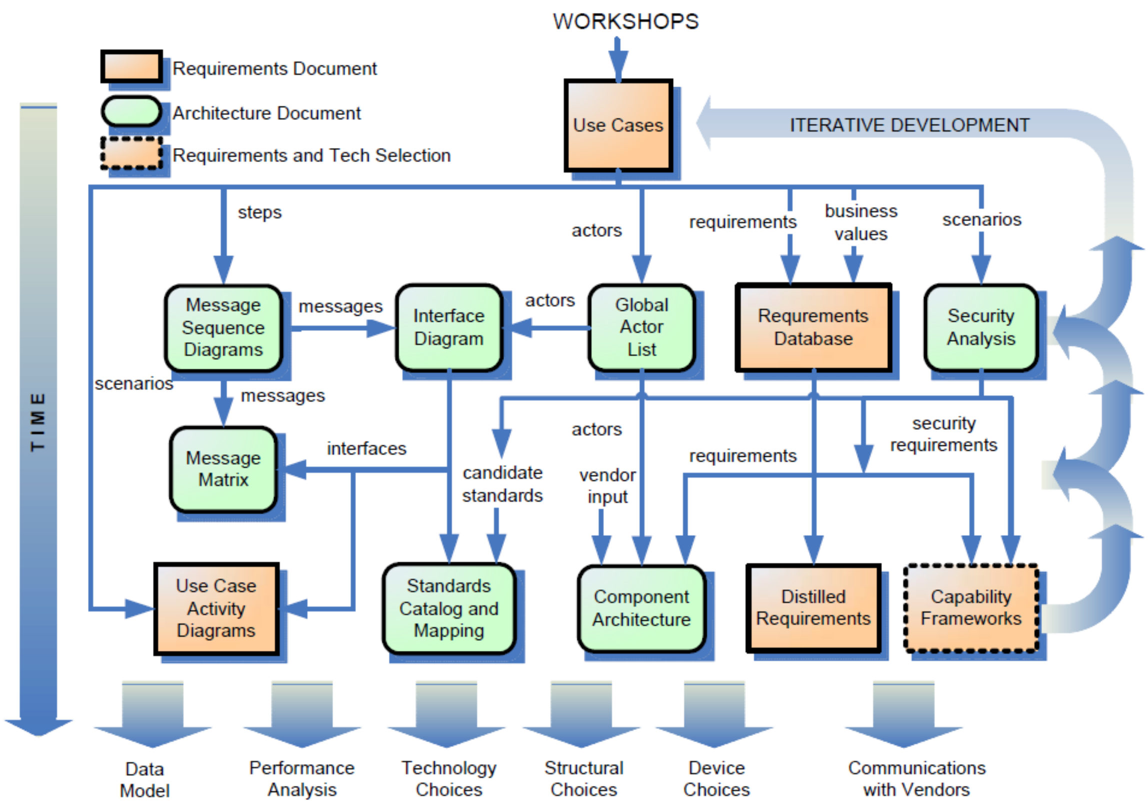
The IntelliGrid^{SM} methodology results in both a plan for the integrated information infrastructure and a study of the requirements and principles required to make particular automation projects work. In basic terms, the IntelliGrid^{SM} architecture is a set of high level concepts that are used to design a technology independent architecture as well as identify and recommend standard technologies, and best practices. These high level concepts include:

- The use of object models and modeling services to give standardized names to data, and to describe their relationships, formats, and interactions in standardized ways
- The development of security policies and the implementation of security technologies where needed, not only to prevent security attacks and inadvertent mistakes, but also to handle recovery from inevitable failures
- The inclusion of network and system management to monitor and control the information infrastructure in a manner similar to the monitoring and control of the power system
- Reduction in stranded assets from systems that can integrate
- Ability to incrementally build upon first steps; and then scale up massively
- Reduced development costs by building on components of IntelliGrid^{SM} architecture systems engineering
- Robustness achieved from structured approaches to systems management
- Necessary architecture to consistently and adequately secure the energy industry

The smart grid infrastructure is defined by the applications and technologies that are built on it. This is at the heart of the "Use Case process" that is used to define the requirements for the smart grid. Use Cases define the applications in a way that can be used to determine the specific requirements for communications infrastructure, new technologies, and information integration. From the Use Cases, thorough and effective test plans may be developed. This process is illustrated in Figure 2-7.

The results of the Use Case analysis will be compared against the existing and emerging technologies, standards and best practices of the industry. The focus will be on what technologies best enable building the new architecture on top of what exists now and what will emerge in the future. The recommended technologies, standards and best practices pertaining to the creation, storage, exchange and usage of various forms of power system information will be evaluated and rated.

Figure 2-7: IntelliGrid[SM] Use Case Driven Interoperability Test Plan Development Process



2.1.1.4.2.2 NIST SmartGrid Interface Reference Model [8]

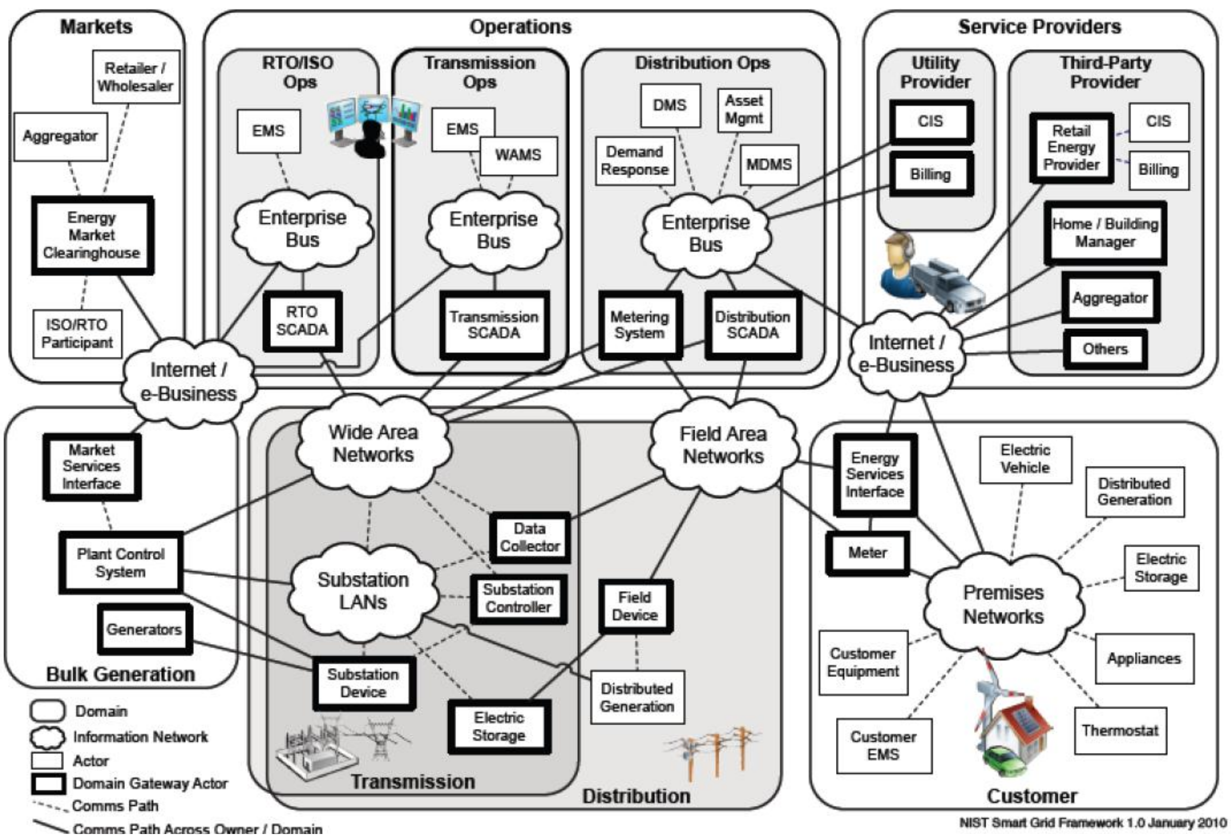
The smart grid is a complex system of systems for which a common understanding of its major building blocks and how they interrelate must be broadly shared. The smart grid will ultimately require hundreds of standards, specifications, and requirements. Some are needed more urgently than others. To prioritize its work, NIST chose to focus initially on standards needed to address the priorities identified in the Federal Energy Regulatory Commission (FERC) Policy Statement, plus additional areas identified by NIST. The eight priority areas were:

- Demand Response and Consumer Energy Efficiency
- Wide-Area Situational Awareness
- Energy Storage
- Electric Transportation
- Advanced Metering Infrastructure
- Distribution Grid Management

- Cyber Security
- Network Communications

NIST, with the assistance of EPRI and using the IntelliGrid℠ methodology, developed a conceptual architectural reference model illustrated in Figure 2-8 to facilitate this shared view. This model identifies interfaces among domains and actors. The model provides a means to analyze Use Cases, identify interfaces for which interoperability standards are needed, and facilitate development of a cyber security strategy.

Figure 2-8: NIST Smart Grid Logical Interface Reference Model



2.1.1.4.2.3 NIST/SGIP Smart Grid Cyber Security Logical Reference Model [11]

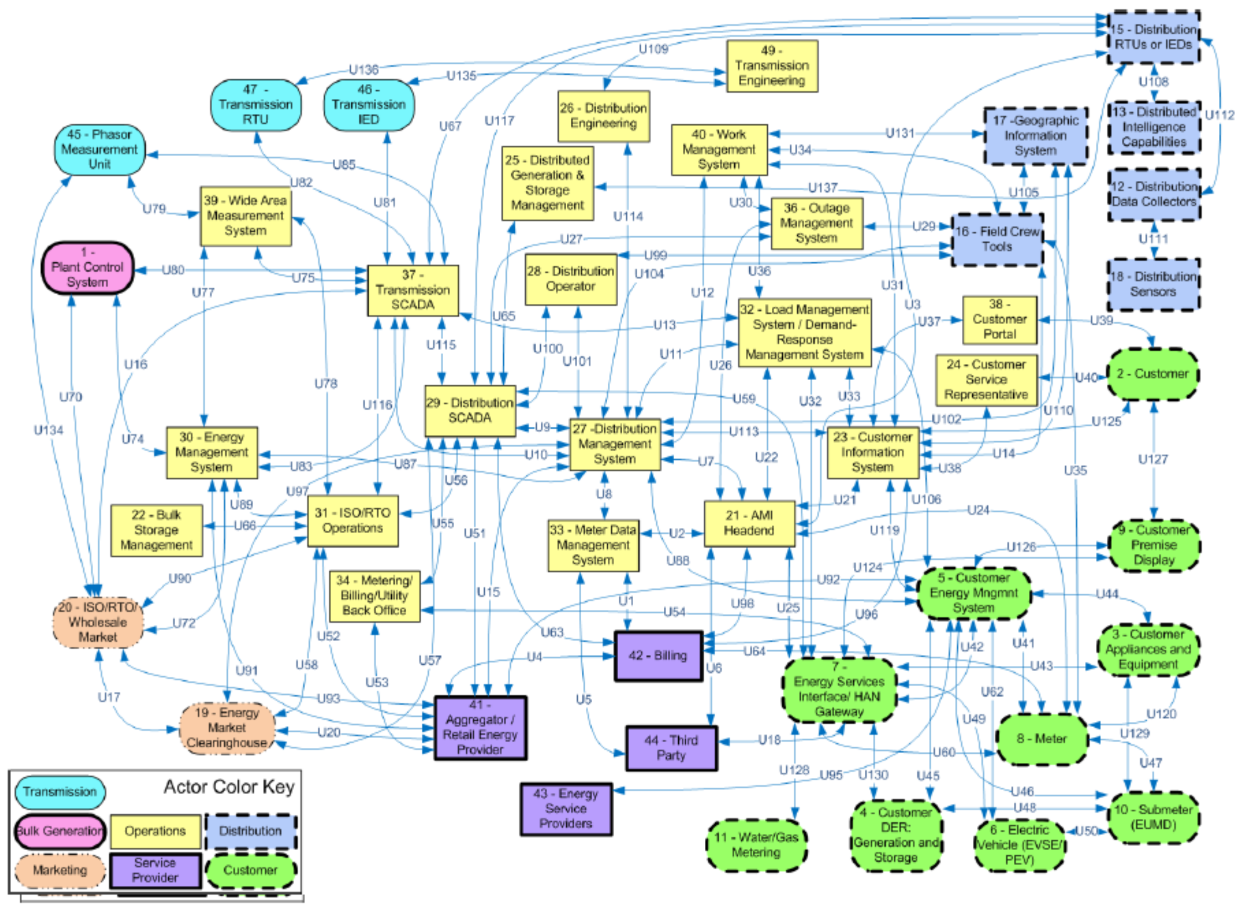
The SGIP Cyber Security Working Group (CSWG) developed a logical reference model of the smart grid, including all the major domains—service providers, customer, transmission, distribution, bulk generation, markets, and operations—that are part of the NIST conceptual model. In the future, the NIST conceptual model and the logical reference model included in this report will be used by the SGIP Architecture Committee (SGAC) to develop a single smart grid architecture that will be used by the CSWG to revise the logical security architecture included in this report.

Communications among actors in the same domain may have similar characteristics and requirements. Domains may contain subdomains. An actor is a device, computer system, software program, or the individual or organization that participates in the smart grid. Actors have the capability to make decisions and to exchange information with other actors. Organizations may have actors in more than one domain. The actors illustrated in this case are representative examples and do not encompass all the actors in the smart grid. Each of the actors may exist in several different varieties and may contain many other actors within them.

The logical reference model represents a blending of the initial set of Use Cases, requirements that were developed at the NIST Smart Grid workshops, the initial NIST Smart Grid Interoperability Roadmap, and the logical interface diagrams for the six FERC and NIST priority areas: electric transportation, electric storage, advanced metering infrastructure, wide area situational awareness (WASA), distribution grid management, and customer premises.

The logical reference model is a work in progress and will be subject to revision and further development. Additional underlying detail as well as additional smart grid functions will be needed to enable more detailed analysis of required security functions. Figure 2-9 illustrates, at a high level, the diversity of systems as well as a first representation of associations between systems and components of the smart grid.

Figure 2-9: NIST Smart Grid Cyber Security Logical Reference Model



2.1.1.4.3 Requirements

Requirements define what the smart grid is and does. Requirements that drive and specify the functions and how they are applied are foundational to the realization of the smart grid. The following are some of the key characteristics of effective requirements:

- Industry policies and rules of governance are well developed, mature, and can be consistently applied
- Requirements are well-developed by domain experts and well documented following mature systems-engineering principles
- Requirements define support for applications and are well developed enough to support their management and cyber security as well

2.1.1.4.3.1 KCP&L Application Use Cases

The Use Case process is a mature, industry-accepted practice for describing system behavior as requests are made from it. Use Cases provide a "who does what in what order" analysis. Use Cases are a means to an end, in that they drive requirements which are rational, comprehensive, and defensible.

The IntelliGrid^{SM} methodology assists in developing Use Cases in a systematic manner, all with the goal of identifying and documenting all significant requirements.

The steps to define a Use Case include:

1. **Review the Scope of the Use Case.** Identify known assumptions, constraints, and business rules for the Use Case.
2. **List the Actors.** What goals do they want to accomplish? What information will they generate/consume?
3. **Identify the Scenario Pre-Conditions and Assumptions.** What must happen before the scenario can start? What conditions can the team assume to exist, or be true, at the start of the scenario?
4. **Identify the Scenario Post-Conditions.** What must happen after the scenario is complete? What is the observable state or status after the implementation of the Use Case?
5. **Identify the Steps for the Scenario.** As each step is defined, identify requirements for that step to occur.
6. **Define Information Exchanged and Requirements for the Steps.** What information is exchanged and between who? What is required for the step to occur (Functional)? What type of targets, behavior, and performance measures must be reached for that requirement (Nonfunctional)?
7. **Identify Alternate Scenarios.** What happens when things go wrong?
8. **Check if We're Done.** Did the primary actor reach its goal?

The KCP&L SGDP team has identified more than 90 use cases to cover the breadth of the KCP&L SGDP. The use cases have been organized into the following groupings:

- Network Communications
- Advanced Metering Infrastructure
- Meter Data Management
- Home Area Network
- SmartEnd-Use
- Demand Response Management
- Distribution Substation Automation
- First Responder
- Distribution Management System
- Plug-in Electric Vehicle Charging

The identified Use Cases are by no means a comprehensive listing of Smart Grid Use Cases. As the smart grid develops, additional Use Cases will be needed to support new and evolving functions and technologies. KCP&L fully expects that this listing of Use Cases will change slightly through the detailed project design process.

The KCP&L project team acknowledges the prior works of many individuals that form the basis of the Use Cases developed specifically for this project. Prior works by EPRI, SCE, AEP, and the OpenHAN organization provided a foundation for the majority of this work product.

2.1.1.4.3.2 Industry Requirement Profiles

Detailed requirements will be determined by using the method and models mentioned in the preceding section, analyzing KCP&L's business objectives for the demonstration, and using the following industry reference documents:

- NIST NISTR 7628 – Smart Grid Cyber Security Strategy and Requirements
- UtilityAMI AMI Enterprise System Requirements Specification v1.0
- UCAIug (ASAP-SG) Security Profile for Distribution Management (draft)
- UCAIug (ASAP-SG) Security Profile for Third Party Data Access (draft)
- UCAIug (ASAP-SG) Security Profile for Advanced Metering Infrastructure v2.0
- UCAIug (OpenHAN) Home Area Network System Requirements Specification v2.0

2.1.1.4.4 Architecture and Design [12]

It is difficult for organizations and industries to change. Many strategic initiatives end in failure because the required changes are viewed in isolation rather than in relation to the complete infrastructure. When building reference model architectures, there are three key architecture types:

- Conceptual – Services (e.g. Outage Detection Service)
- Logical – Components (e.g. Outage Management System)
- Physical – Implementations (e.g. OMS)

Developing a conceptual SmartGrid architecture model based on goals and requirements will further enhance an organization's ability to be effective in the implementation of core strategy and vision.

The National Institute of Standards and Technology (NIST) Smart Grid Interoperability Panel (SGIP) Smart Grid Architecture Committee (SGAC) is responsible for creating and refining a Smart Grid conceptual architecture reference model. The process for developing a generic Smart Grid conceptual architecture was based on three key process tasks:

- Developing grid architecture goals from national energy goals and national policy documents
- Developing a formalized list of requirements relating to and mapped to each of the accepted grid architecture goals
- Developing a list of energy services based on the list of accepted requirements

The final deliverable of a generic Smart Grid conceptual architecture will allow grid participants to develop their own internal logical and physical architectures.

The systems architecture and designs developed for the KCP&L SGDP will satisfy the requirements developed through the processes outlined in the preceding section. It will leverage existing industry reference architectures and architectural artifacts, such as those developed by GWAC, NIST, and UCAIug.

The SGDP architecture and systems design will also leverage the IEC 61968 series for Application Integration at Electric Utilities, the IEC 61850 series for Communication Networks and Systems in Substations, and other emerging standards discussed in the next section.

The KCP&L project team is participating in the NIST/SGIP sponsored SmartGrid Conceptual Architecture Model development efforts and as this architectural reference emerges, it will be considered for adoption into the KCP&L SGDP system architecture.

2.1.1.4.5 Standards

This SGDP architecture and standards to be implemented are closely aligned with the *NIST Special Publication 1108 - NIST Framework and Roadmap for Smart Grid Interoperability Standards*. This document identifies guiding principles for the adoption of standards for the smart grid and the smart grid domains to which interfaces and standards apply. It also identifies standards for consideration and incorporation into smart grid architectures and solution designs.

Additionally, in the NIST Framework, NIST recommends some criteria for adoption of standards. Generally, these involve openness and accessibility. NIST believes that smart grid interoperability standards should be open. The term "open" standard as used by NIST means that a standard is "developed and maintained through a collaborative, consensus-driven process that is open to participation by all relevant and materially affected parties and not dominated or under the control of a single organization or group of organizations, and readily and reasonably available to all for smart grid applications". In addition, NIST states that smart grid interoperability standards should be developed and implemented internationally, wherever practical. Figure 2-10 summarizes the NIST criteria for standards adoption to achieve interoperability which have been adopted by KCP&L.

2.1.1.4.6 Summary

This section presented a strategy, approach, models and methods for achieving interoperability between components of the KCP&L SGDP.

Adoption of the applicable standards, and the other aspects of the frameworks described in this section will ensure that interoperability is appropriately aligned with business objectives including integration with other market participants.

Additionally, not all standards considered may ultimately be adopted. However, each will be considered for adoption along with other emerging standards and guidelines using the structured approach outlined in this document and incorporated into vendor agreements and procurement language as appropriate. Adopting the NIST and GWAC Interoperability frameworks, along with the EPRI methods, will ensure that interoperability is a primary consideration throughout the lifecycle of the KCP&L SmartGrid solution, and that the appropriate artifacts are documented.

Figure 2-10: NIST Guiding Principles for Identifying Standards for Implementation

For *Release 2.0,* a standard, specification, or guideline is evaluated on whether it:

- Is well-established and widely acknowledged as important to the Smart Grid.
- Is an open, stable, and mature industry-level standard developed in a consensus process from a standards development organization (SDO).
- Enables the transition of the legacy power grid to the Smart Grid.
- Has, or is expected to have, significant implementations, adoption, and use.
- Is supported by an SDO or standards- or specification-setting organization (SSO) such as a users group to ensure that it is regularly revised and improved to meet changing requirements and that there is a strategy for continued relevance.
- Is developed and adopted internationally, wherever practical.
- Is integrated and harmonized, or there is a plan to integrate and harmonize it with complementing standards across the utility enterprise through the use of an industry architecture that documents key points of interoperability and interfaces.
- Enables one or more of the framework characteristics as defined by EISA* or enables one or more of the six chief characteristics of the envisioned Smart Grid.†
- Addresses, or is likely to address, anticipated Smart Grid requirements identified through the NIST workshops and other stakeholder engagement.
- Is applicable to one of the priority areas identified by FERC‡ and NIST:
  - Demand Response and Consumer Energy Efficiency;
  - Wide Area Situational Awareness;
  - Electric Storage;
  - Electric Transportation;
  - Advanced Metering Infrastructure;
  - Distribution Grid Management;
  - Cybersecurity; and
  - Network Communications.
- Focuses on the semantic understanding layer of the GWAC stack,* which has been identified as most critical to Smart Grid interoperability.
- Is openly available under fair, reasonable, and non-discriminatory terms.
- Has associated conformance tests or a strategy for achieving them.
- Accommodates legacy implementations.
- Allows for additional functionality and innovation through:
  - *Symmetry* – facilitates bidirectional flows of energy and information.
  - *Transparency* – supports a transparent and auditable chain of transactions.
  - *Composition* – facilitates building of complex interfaces from simpler ones.
  - *Extensibility* – enables adding new functions or modifying existing ones.
  - *Loose coupling* – helps to create a flexible platform that can support valid bilateral and multilateral transactions without elaborate prearrangement.**
  - *Layered systems* – separates functions, with each layer providing services to the layer above and receiving services from the layer below.
  - *Shallow integration* – does not require detailed mutual information to interact with other managed or configured components.

* GridWise Architecture Council, GridWise Interoperability Context-Setting Framework, March 2008.

** While loose coupling is desirable for general applications, tight coupling often will be required for critical infrastructure controls.

2.1.2 Cyber Security Strategy & Plan [13]

The KCP&L project team developed and published a "SmartGrid Cyber Security Plan" that detailed a strategy and approach for implementing cyber security in the KCP&L SGDP. The following subsections provide an overview of the significant elements of the cyber security plan developed for the project.

The cyber security strategy and approach is intended to have broad applicability beyond the SGDP including future development of the portions of the SGDP that ultimately extend into production systems.

The terms cyber security and cyber infrastructure are used throughout this document. The following definitions are used in the U.S. National Infrastructure Protection Plan (NIPP) and are included to ensure a common understanding:

- Cyber Security: The protection required to ensure confidentiality, integrity and availability of the electronic information communication system
- Cyber Infrastructure: Includes electronic information and communications systems and services and the information contained in these systems and services. Information and communications systems and services are composed of all hardware and software that process, store, and communicate information, or any combination of all of these elements. Processing includes the creation, access, modification, and destruction of information. Storage includes paper, magnetic, electronic, and all other media types. Communications include sharing and distribution of information. For example, computer systems, control systems (e.g., SCADA), networks, including the Internet and cyber services (e.g., managed security services), are all part of cyber infrastructure.

2.1.2.1 Smart Grid Cyber Security Trends & Challenges

Cyber security for the electric grid is evolving in response to several accelerating trends:

- Increasing scrutiny of regulators, customers, shareholders and external entities due to a heightened awareness of the potential for a catastrophic failure or attack on the nation's critical infrastructure
- Emerging threats to the security of the grid by terrorist nation-states, countries and criminal organizations who may target the electric grid with increasingly sophisticated methods of attack
- Increasing dependence on "smart" networked, IP-enabled devices to monitor and control the grid and decreasing reliance on serial devices communicating over closed networks
- Moving from proprietary systems requiring special expertise known only to a few individuals with specialized skills towards cost and efficiency advantages gained through the use of open operating systems, application platforms and communications protocols
- Increasing use of efficiencies to be gained through using wireless communication and public communications networks, often using non-proprietary technologies and protocols
- Increasing the degree of the distributed electric grid within generation and markets, and the evolution of domains such as distributed generation assets that are not under the direct ownership and control of the utility

The factors noted above contribute to several challenges when considering an approach to securing the grid:

- Cyber security mechanisms must be employed throughout the system life cycle and end-to-end to secure all of the potential attack points in the grid. These attack points are increasing in number. Also, the risk of compromise has increased due to both intentional and unintentional traditional IT-oriented threats, which increasingly have the potential to affect control systems within the grid.

- Reliability and availability of the grid remain primary considerations, and security controls must not degrade grid reliability and availability.
- Utilities, vendors and standards bodies have been slow to respond to security challenges and incorporate cyber security mechanisms into their products, partially because of these challenges, shifting business requirements and changing regulatory landscapes.
- Mechanisms to detect anomalous behavior within the grid indicating that a cyber-attack on control systems is underway are immature, and some standard operating procedures and disaster scenarios do not adequately account for responses to cyber events.

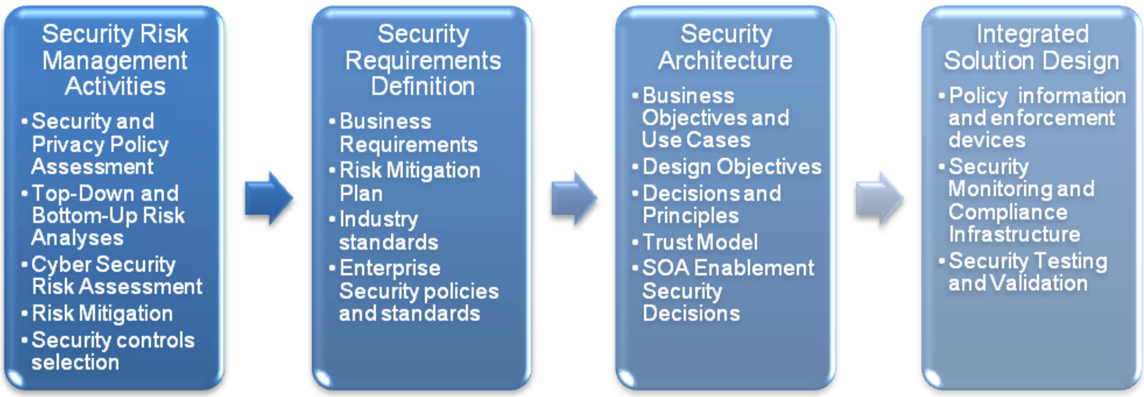
2.1.2.2 Cyber Security Strategy & Approach

The challenges outlined in the preceding section will be met through the development of a cyber-security controls framework, design, architecture, and infrastructure that ensures that technologies, polices, processes and procedures result in adherence to existing cyber security regulations, evolving smart grid security requirements and KCP&L's business requirements. This will be accomplished by adoption of the NIST/EPRI security framework (NIST SP 1108R2: NIST Framework and Roadmap for Smart Grid Interoperability Standards Release 2.0 February 2012 and NISTIR-7628: Guidelines for Smart Grid Cyber Security – August 2010) and other frameworks, subject to KCP&L's business requirements and SGDP budget considerations. Implementing the controls identified in the framework consists of the following activities to provide end-to-end security:

- Perform a comprehensive risk assessment [14] and adopt a risk management strategy to ensure risk-based decision making throughout the system's life cycle
  - Categorize the interfaces according to the framework (i.e., the types of domains that are involved in particular use cases)
  - Identify and analyze all logical interfaces to determine the risks to confidentiality, integrity and availability exposed through them
- Determine cyber security requirements
- Select appropriate controls and technical countermeasures to mitigate the risks and rationalize these in a cyber-security architecture
- Develop and deploy a cyber-security governance, risk management and compliance process and tools tailored for the KCP&L operations environment and project budget
- Implement the countermeasures and controls, leveraging existing cyber security infrastructure capabilities to the extent possible according to an integrated secure systems design
- Test and validate whether the deployed cyber security infrastructure is providing the expected security assurance
- Develop plans to remediate cyber security gaps and address residual risks
- Develop and implement cyber security criteria in procurement language and device vendor selection in accordance with best practices
- Monitor the ongoing development of smart grid cyber security standards and requirements for incorporation into KCP&L's strategic plans

The overall cyber security strategy examines both domain-specific and common requirements when developing a mitigation strategy to ensure interoperability of solutions across different parts of the infrastructure. Implementation of a cyber-security strategy requires the development of an overall cyber security risk management framework for the smart grid. This framework is based on existing risk management approaches developed by KCP&L and other best practice organizations.

Figure 2-11: KCP&L SmartGrid Security Strategy and Approach



This risk-driven approach to cyber security, depicted in Figure 2-11 above, along with architectural discipline imposed through governance and compliance assessment frameworks will ensure that security expenditures are aligned with business objectives and project budgets. In conjunction with the cyber security architecture, security design objectives will be identified for authentication, access control, logging and auditing, data confidentiality, data integrity and non-repudiation, Service-Oriented Architecture (SOA) and messaging security.

Once the conceptual architecture is completed, high-level and detailed designs will be completed for the cyber security infrastructure. The designs will be documented, refined and validated against the architecture through use cases and scenarios. The risk assessment will be updated if new risks are discovered and additional controls and countermeasures will be deployed using risk mitigation methods within the risk management process.

Well-defined processes, methods, and software solutions are designed to assist and automate the implementation of risk and compliance management processes. Therefore, the solution involves identifying and customizing tools to meet the specific requirements of KCP&L and integrating these tools and methods into a comprehensive solution applicable to the operations environment. The infrastructure will be deployed in a manner consistent with the Government, Risk, and Compliance (GRC) framework shown in Figure 2-12.

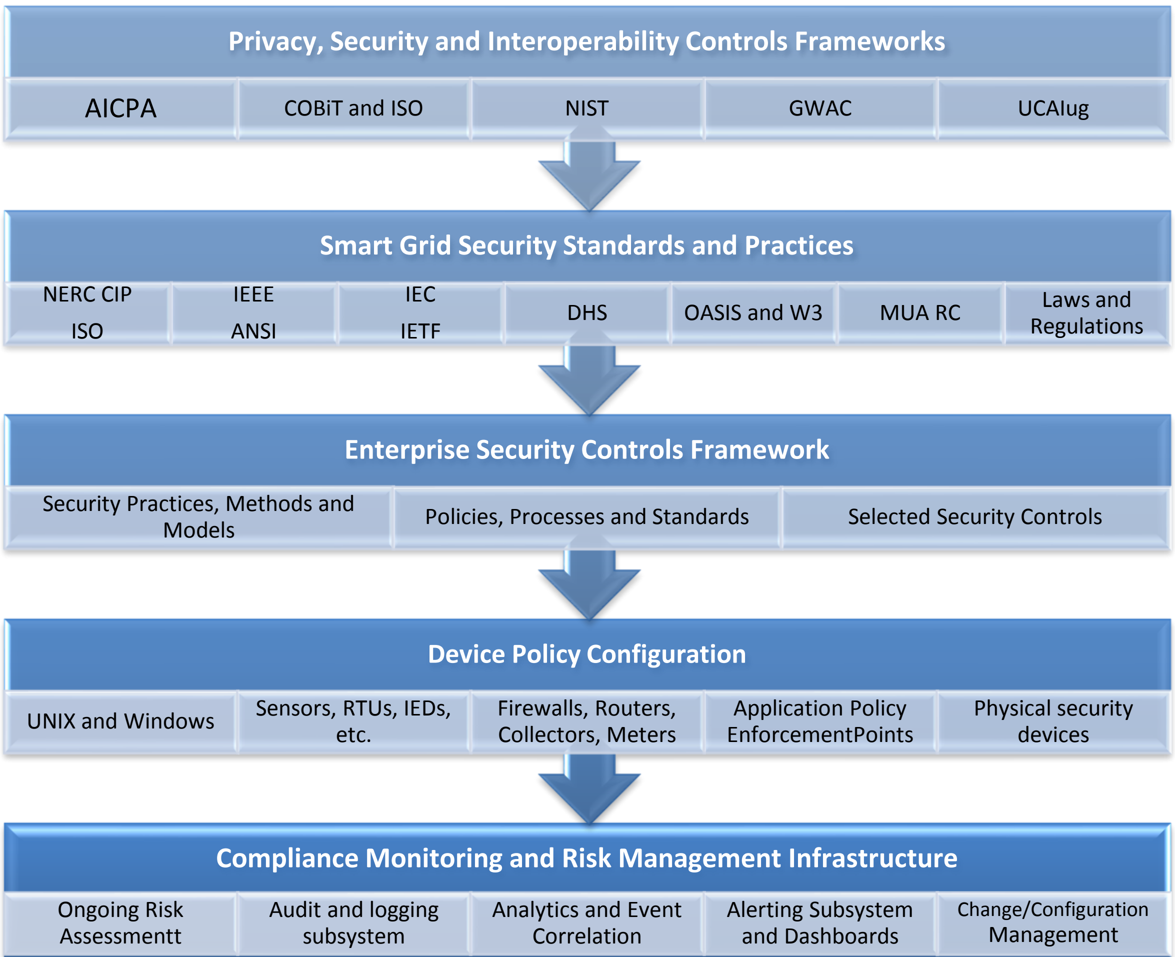
2.1.2.3 Smart Grid Cyber Security Design Considerations

2.1.2.3.1 Cyber Security Standards

In addition to being required by regulatory and compliance audit agencies, security policies, procedures and guidelines form the basis of a risk management program. They express management's intent with regard to the cyber security program and compliance with applicable laws and regulations, assign roles and responsibilities and define who is accountable for cyber security activities. The increasing interoperability of traditional IT systems and control systems, along with increased scrutiny of security controls by external agencies, makes the establishment and maintenance of a standards-based cyber security policy framework an essential component of the security program.

KCP&L has a policy framework that aligns security policies to IT and business policies. These policies will be analyzed for their relevance to the smart grid. Cyber security policies applicable to the operations environment will be reviewed and updates to reflect the requirements of smart grid operations and compliance with emerging standards will be identified. Gaps in the policy framework will be identified.

Figure 2-12: KCP&L GRC Management Framework



The standards and frameworks listed in Table 2-2 and Table 2-3 are relevant to smart grid cyber security best practices with particular emphasis on:

- NERC - Critical Infrastructure Protection (CIP) Version 3.0
- NISTIR-7628 Guidelines for Smart Grid Cyber Security – August 2010

Table 2-2: Summary of Applicable Cyber Security Standards

Standards	Description	Date
NISTIR-7628	Guidelines for Smart Grid Cyber Security	August 2010
NERC - CIP	Critical Infrastructure Protection (CIP) v3.0	Various
NIST SP 800-30	Guide for Conducting Risk Assessments Rev. 1	September 2012
NIST SP 800-53	Security and Privacy Controls for Federal Information Systems and Organizations Rev. 4	April 2013

Table 2-3: Summary of Applicable Cyber Security Frameworks

Frameworks	Description	Date
NIST SP 1108R2	NIST Framework and Roadmap for Smart Grid Interoperability Standards Release 2.0	February 2012
UCAIug	Security Profile for AMI v2.1	October 2012
UCAIug	Security Profile for DM v1.0	February 2012
UCAIug	Security Profile for OpenADR v0.03	March 2012
UCAIug	Security Profile for Substation Automation v0.15	September 2012

Controls implementing these standards where required or where warranted based on best practices from other evolving smart grid standards will be expressed in cyber security policies, procedures and guidelines as appropriate. Compliance will be assessed through use of the GRC framework. The framework will ensure that:

- Policies, procedures and guidelines will be documented in a central repository
- The policy maintenance life cycle will include regular review and incorporation of relevant standards
- Compliance is assessed periodically
- Exceptions will be documented and associated workflows created
- Audit readiness is maintained

2.1.2.3.2 Risk Management

The KCP&L risk management framework defines the processes for combining impact, vulnerability, and threat information to produce an assessment of risk to the KCP&L SmartGrid and to its domains and sub-domains, such as businesses and customer premises. Risk is the potential for an unwanted outcome resulting from an incident, event, or occurrence, as determined by its likelihood and the associated impacts. Because the smart grid includes systems and components from the IT, telecommunications, and energy sectors, the risk management framework will be applied on an asset, system, and network basis, as applicable. The goal is to ensure that a comprehensive assessment of the systems and components of the KCP&L SGDP is completed. The framework will make use of the NIST/EPRI cyber security framework as a reference construct to ensure that applicable requirements are incorporated.

The risks of operating a system cannot be completely eliminated. After the implementation of controls, residual risks will be tracked and subject to the further assessment activities to determine methods of reducing the residual risk to acceptable levels. The risk assessment is used as input into the KCP&L Risk Management Process, which includes methods and activities that result in risk mitigation or acceptance. The Risk Management Process is depicted in Figure 2-13 below.

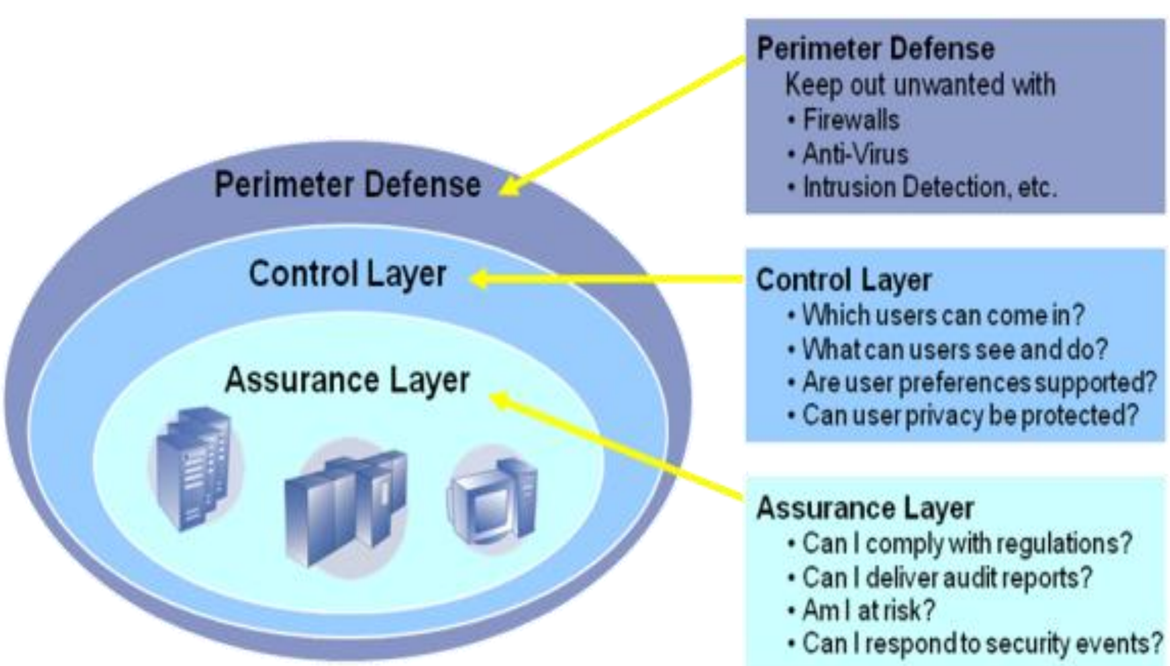
Following the risk assessment, the next step is to select and tailor the cyber security and business requirements. These requirements will drive a security architecture, which will be integrated with the systems architecture, NIST and other industry reference architectures. Integration with the NIST/EPRI reference architecture [8] [15] and other security standards will help ensure interoperability of components.

Figure 2-13: KCP&L Risk Management Process

2.1.2.3.3 Defense in Depth

Defense in depth is the layering of security controls in such a way that the damage of an exploit is minimized. An attacker must circumvent multiple controls to exploit vulnerabilities or gain unauthorized access. Security mechanisms are also layered in such a way as to limit the damage resulting from a compromise. A medieval castle with its moats, walls and other defenses is an example of a defense in depth security stance. A well-defended castle does not rely on a single defense to protect the most valuable assets, but on multiple layers. The security architecture, as illustrated in Figure 2-14 below provides for layers of security to form a defense in depth cyber security posture.

Figure 2-14: KCP&L *Defense in Depth* Security Posture



The architecture may include the following components to achieve a layered defense that complies with laws and regulations and meets KCP&L's business and budget requirements:

Perimeter Security:

- Protocol-level firewalls
- Intrusion detection (network and host-based)
- Application-level firewalls
- Wireless and endpoint security
- Physical security of cyber assets

Control Layer:

- Identity and access management
- Application security
- Compliance monitoring

Assurance Layer:

- Cyber security governance, risk and compliance management
- Cyber security policy development
- Cyber security testing
- Cyber security incident response

2.1.2.3.4 Trust Model

One important aspect of the smart grid that has not been sufficiently addressed by the industry is the development of a trust model for the smart grid. This section describes the method that KCP&L will use to develop a solution architecture that implements a trustworthy design.

Trust is defined as the measure of confidence that can be placed in the predictable occurrence of an anticipated event or an expected outcome of a process or activity. For business activities that rely on IT, trust is dependent on both the nature of the agreement between the participants and the correct and reliable operation of the IT solution.

An objective of a trust model for the KCP&L SGDP is to implement mechanisms and strategies for trustworthiness of systems protecting the confidentiality, integrity and availability of information between actors (requesters and consumers of information) and domains by ensuring accountability for actions. In a distributed information system, the ultimate concern of a trust model should be the information itself, rather than the sources that supply the information. A good trust model facilitates this type of interaction without hindering the more traditional approach to trustworthiness – i.e., interacting only with trusted sources of information.

The implementation of a trust model for the smart grid has many complex dimensions:

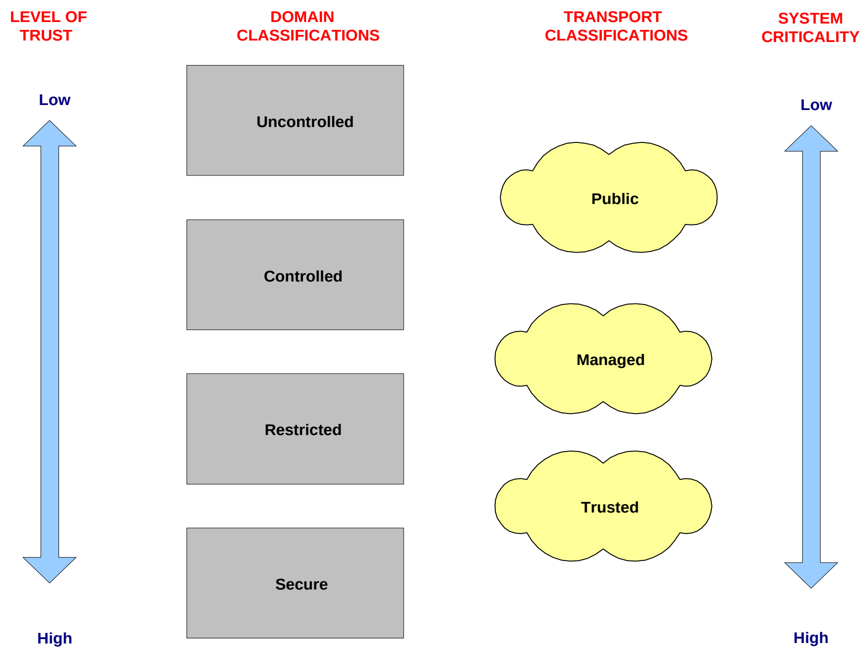
- Control systems with interfaces between them are often in different organizations, and therefore, the chain of trust between them is more important
- By definition, market operations are across organizational boundaries, thus posing trust issues
- The implementation of a model that enables network and systems architecture and facilitates effective communication among the various business entities without inadvertent or unauthorized sharing of trade secrets, business strategies or operational data and activities, while enabling sharing of fine-grained energy data and other information between organizations (and units within organizations) to realize the advantages of smart grid technology

- The management of large amounts of privacy-sensitive data in an efficient and responsible manner while complying with regulations regardless of the current state and location of data
- Trust of event or systems data
- Trust relationships between field devices and security policy enforcement points
- Trust within mesh networks, between leaf mesh nodes and gateways, and between mesh and non-mesh networks and interconnected mesh networks having different trust models
- The establishment of a user trust model for administration of keys, passwords and other sensitive data that does not create an undesirable amount of dependence on IT personnel and avoids an actor becoming a single point of failure

The activities undertaken using the secure architecture method will result in development of a conceptual trust model for the KCP&L SGDP.

Once the KCP&L solution architecture has been defined and mapped to the NIST framework, the architecture will be decomposed into its component domains. Figure 2-15 provides an example of semantics associated with varying trust levels of different domains and includes the security zones and the interfaces between them.

Figure 2-15: KCP&L Trust Model



Different semantics than those shown above may be used in the KCP&L SmartGrid trust model, however the process of applying the trust model will be the same. Different security levels that depend on the design of the network and systems architecture, security infrastructure and how trusted the overall system and its elements are will be assigned. This model will help put the choice of technologies and architectural decisions within a security context and guide the choice of security solutions.

One realistic expectation of the usefulness of the trust model, assured by application of this method, is that designers and integrators of IT solutions will enlist all reasonable measures to achieve the correct and reliable operation of IT solutions throughout the design, development, and deployment phases of the solution life cycle.

2.1.3 Education & Outreach Strategy & Plan [16]

The KCP&L project team developed and published a "SmartGrid Education & Outreach Plan" that detailed a strategy and approach for conducting SmartGrid Education and Outreach elements for the KCP&L SGDP. The following subsections provide an overview of the significant elements of the education and outreach plan developed for the project.

2.1.3.1 Introduction

There are numerous examples from other utilities around the country that demonstrate that the overall success of a smart grid project is closely tied to the overall success of the utility's public education and outreach plan. In the case of the KCP&L Green Impact Zone SGDP, the geographic boundaries and demographic mix of the customer base present a unique set of communications challenges and opportunities. In response, KCP&L has developed a highly targeted, multi-phased public education and outreach effort that will drive awareness and understanding of SmartGrid as well as encourage product acceptance and adoption. KCP&L is working in close collaboration with its vendor partners and a wide range of community groups, most notably, Kansas City's Green Impact Zone, an initiative led by U.S. Rep. Emanuel Cleaver II to focus federal stimulus dollars on a 150-square block geographic area in Kansas City's urban core. In addition, although the current SmartGrid pilot project is limited to only 14,000 KCP&L customers, there is the much broader audience of approximately 800,000 customers across the company's service territory. The success and lessons learned over the next five years will help determine the likelihood and plan for future deployment.

2.1.3.2 Education & Outreach Messaging

2.1.3.2.1 SmartGrid Demonstration Project Messages

The key SGDP messages that support KCP&L's SmartGrid communications objectives include:

- SmartGrid will provide customers with enhanced energy information and tools, helping them manage usage and control costs.
- SmartGrid will improve system reliability, energy efficiency and air quality.
- The SGDP will allow KCP&L to obtain valuable customer feedback, leading to system-wide improvements for the entire customer base.
- Through KCP&L's testing, evaluating and reporting, the SGDP will serve as a blueprint for future smart grid implementations, and it will accelerate the realization of the "utility of the future."
- SmartGrid will utilize advanced technology, including renewable generation, storage resources, cutting-edge substation and distribution automation and control, energy management interfaces, and innovative customer programs and rate structures.

2.1.3.2.2 Industry-wide Smart Grid Messages

The overarching messages above were crafted to support and enhance these broader smart grid objectives, as articulated by "Seven Principal Characteristics of the Modern Grid," outlined in The NETL Modern Grid Initiative:

- Self-heals: The modern grid will perform continuous self-assessments to detect, analyze, respond to, and as needed, restore grid components or network sections.
- Motivates and includes the consumer: The active participation of consumers in electricity markets brings tangible benefits to both the grid and the environment, while reducing the cost of delivered electricity.
- Resists attack: Security requires a system-wide solution that will reduce physical and cyber vulnerabilities and recover rapidly from disruptions.

- Provides power quality for 21st century needs: The modern grid will provide the quality of power desired by today's users, as reflected in emerging industry standards. These demands and standards will drive the grid.
- Accommodates all generation and storage options: The modern grid will seamlessly integrate many types of electrical generation and storage systems with a simplified interconnection process analogous to "plug-and-play."
- Enables markets: This characteristic is particularly important because open-access markets expose and shed inefficiencies. The modern grid will enable more market participation through increased generation paths, more efficient aggregated demand response initiatives and the placement of energy storage and resources within a more reliable distribution system.
- Optimizes assets and operates efficiently: The modern grid's assets and its maintenance will be managed in concert to deliver desired functionality at minimum cost.

2.1.3.3 Education & Outreach Audiences

Throughout the duration of this project, KCP&L needs to communicate its key messages to a number of audiences, including:

- SmartGrid Demonstration Area Customers (14,000)
- All KCP&L Customers (800,000)
- KCP&L Employees (3,600)
- State Agencies, Legislators and Regulators
- Utilities and Smart Grid Industry

Within each key audience group, KCP&L has identified a number of key stakeholder groups that are also targets for education and outreach. In some cases, these groups and organizations are the vehicle to reach the target audiences, and in other cases they are intended to serve as advocates and supporters for the SGDP.

2.1.3.3.1 SmartGrid Demonstration Area Customers

KCP&L's SGDP has unique customer demographics and geographic area – in and around the Green Impact Zone. This may be one of the only projects of its kind to be focused on the urban core with such a high percentage of low-to-moderate income residents. This presents a number of unique communications and education challenges that KCP&L will address.

Table 2-4: Green Impact Zone Demographic Chart

Metric	SmartGrid Demonstration Area	Green Impact Zone
Population	19,960	8,374
Population in Poverty	23%	31%
KCP&L Customer Accounts	11,265	2,897
Median Household Income	$28,000	$22,000
Ethnicity: White, non-Hispanic	38%	7%
Ethnicity: Black, non-Hispanic	52%	89%
Ethnicity: Hispanic	5%	2%
Age: < 25 years	37%	43%
Age: 25-39 years	25%	20%
Age: 40-59 years	24%	22%
Age: > 60 years	14%	15%
Average Monthly Electric Bill	$85.10	$87.01

Within this audience group, the key stakeholders include:

- Individual Customers
- Neighborhood Groups
- Schools
- Community Leaders
- Elected Officials
- Green Impact Zone Partners

2.1.3.3.2 All KCP&L Customers

While customers living within the SGDP area will be the first affected by SmartGrid initiatives, what KCP&L learns from the project will eventually impact all KCP&L customers. As such, outreach to the entirety of KCP&L's customer base will be an important part of SmartGrid communications.

Within this audience group, the key stakeholders include:

- Residential Customers
- Commercial Customers
- Industrial Customers

2.1.3.3.3 KCP&L Employees

As media coverage of and interest in the project in the broader service territory increases, KCP&L employees will be asked by friends, family and neighbors about SmartGrid. The 3,600 KCP&L employees can be utilized as SmartGrid ambassadors, but KCP&L will need to provide them with ongoing communications in order to make them effective.

Within this audience group, the key stakeholders include:

- Customer Care Departments
- Engineering and Operating Departments
- KCP&L Employees Living in the Project Demonstration Area

2.1.3.3.4 State Agencies, Legislators and Regulators

The individuals in this audience are charged with representing the community. They include elected or appointed individuals, who are especially sensitive to activities that may affect their constituents. Educating this audience is critical to ensuring continued support for SmartGrid, as these individuals will want to be informed so that they can answer any questions raised.

Within this audience group, the key stakeholders include:

- Missouri Public Service Commission & Staff
- Kansas Corporation Commission & Staff
- Missouri Office of Public Counsel
- Elected Officials

2.1.3.3.5 Utilities and Smart Grid Industry

One of the main goals of this project is to serve as a blueprint for future integrated smart grid demonstrations and implementations throughout the country. The project seeks to define, validate and verify the necessary parameters and potential solution adjustments for KCP&L, and the industry, to plan and implement a system-wide roll-out of the successful smart grid technologies and processes. In order to do this, KCP&L will need to effectively communicate and share knowledge with other utilities and the smart grid industry as a whole.

Within this audience group, the key stakeholders include:

- Department of Energy
- National Energy Technology Laboratory
- National Institute of Standards & Technology
- Smart Grid Interoperability Panel
- Professional Associations (IEEE, NSPE, etc.)
- Labor Organizations (IBEW)

2.1.3.4 Value Proposition Groups

The key, high-level messages outlined above will be tailored for each of the audience groups outlined above and focused on the appropriate value proposition area.

2.1.3.4.1 The Consumer

Individual residential consumers are primarily interested in what the smart grid will do for them as individuals. The consumer value proposition answers the question, "What's in it for me?" Some of the consumer benefits include the following:

- Information: Smart grid products will provide customers more information about their energy usage and help them learn which end-use devices and behaviors influence their consumption pattern the most.
- Choice: Customers will be offered products and services not previously available to them, and they will be able to decide which they want to use. Some of the new opportunities include consumer-owned generation and storage resources.
- Control: New smart grid products and tools will give customers the ability to manage their electricity use, which can help them save money on their monthly electric bills.
- Convenience: The new technologies will enable KCP&L to provide faster customer service: meter alerts of outages, remote service connect/reconnection and 15 minute interval data to help respond to customer inquiries.
- Reliability: The updated system will manage the grid to prevent outages and restore service more quickly when outages do occur.

2.1.3.4.2 The Utility

The utility value proposition answers the question, "What's in it for KCP&L?" It must be noted that direct utility benefits are also indirect consumer benefits, as utility savings are used to reduce the upward pressure on rates. The smart grid is expected to provide benefits in a number of utility operational areas, some of which include:

- Improved reliability by enabling distribution automation as well as access to real-time operating data on critical substation equipment
- Reduced energy delivery cost through increased automation and ability to predict and proactively address maintenance strategies
- Improved customer satisfaction
- Improved carbon footprint

2.1.3.4.3 Society

The societal value proposition answers the question, “What’s in it for us?” The smart grid is expected to provide benefits in a number of societal areas, some of which include:

- Downward pressure on electricity prices
- Improved reliability, reducing losses that impact consumers and society
- Increased grid robustness, improving grid security
- Reduced emissions
- New jobs and growth in gross domestic product
- Transformation of the transportation sector leading to a reduction in the U.S. dependence on foreign oil

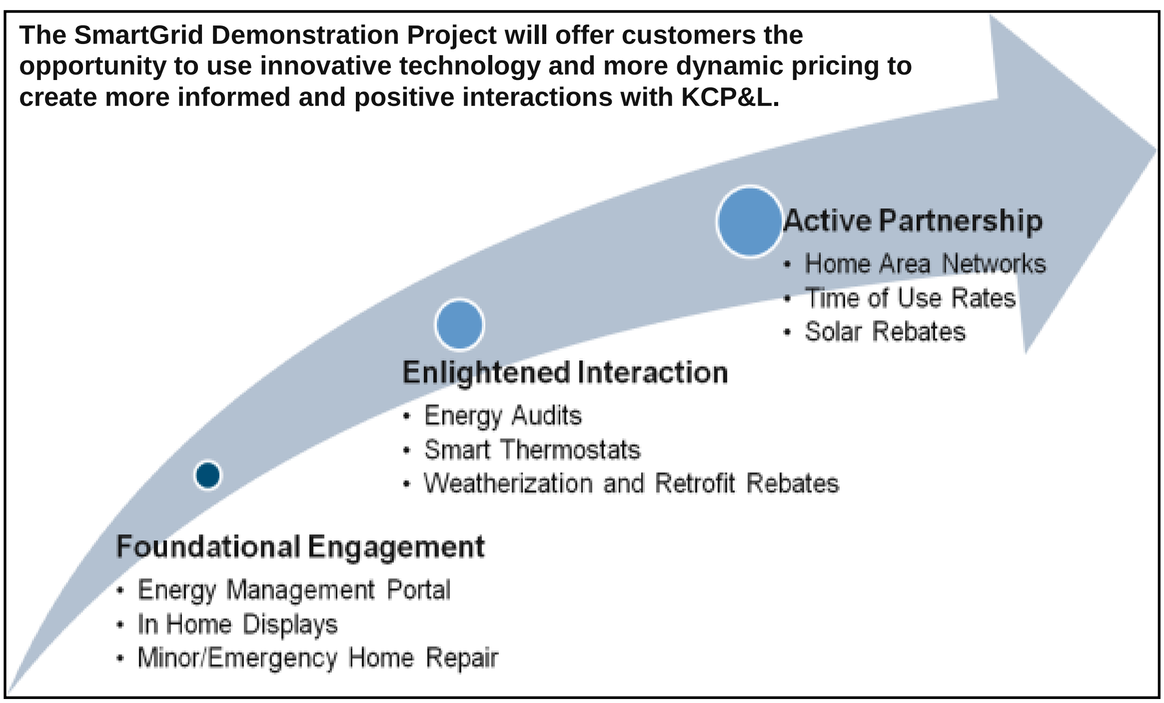
2.1.3.5 Communications Approach

KCP&L intends to educate and engage consumers through a highly targeted, integrated marketing campaign consisting of a variety of tactics across a range of channels for optimal impact. Strategic considerations include:

- Frequent and proactive customer communication, well ahead of customer impacts
- Engagement of key leaders and company ambassadors
- Regular face-to-face communication with customers
- Opportunities for customers to “touch and feel” improvements and products
- Pairing of KCP&L representatives with neighborhood groups and other key organizations
- Cultivation of third-party key leader support

As KCP&L progresses with its SGDP, customers are given the opportunity to move along a continuum tied to value proposition (Figure 2-16). SmartGrid gives them the opportunity to use innovative technology to create a more informed and effective interaction with KCP&L.

Figure 2-16: Customer Value Proposition



2.1.4 Metrics & Benefits [6]

At the beginning of the project, the KCP&L project team developed and published a "SmartGrid Metrics & Benefits Reporting Plan" that set forth the objectives, expected benefits, key asset deployment milestones, Build and Impact Metrics, associated data collection, aggregation and analysis methods, monetary investments, baseline data methodologies, market place innovation, and collaboration/interaction with the DOE necessary to accomplish KCP&L's fully integrated SGDP. The following sections provide a summary the plan along with plan adjustments that have been made in response to DOE guidance and to incorporate the DOE Smart Grid Computational Tool (SGCT) analysis techniques.

2.1.4.1 Project Benefits

KCP&L's SGDP is designed as a means to test and evaluate a potential step change improvement in KCP&L's electricity distribution system. Specifically, the project team is designing a system with a communication architecture that will facilitate automated system monitoring and control with open-source systems that will allow the integration of technologies and components from multiple vendors in a best-of-breed system of solutions — including a new architecture and system that will enable an interoperable, secure network of components.

The project team expects this SGDP to identify significant potential grid performance improvements as a result of the technologies and solutions considered. Substation and distributed feeder line automation systems can significantly reduce O&M costs, improve reliability, and enhance the environmental footprint through automated fault location detection, automated switch operation, improved voltage control and regulation, improved Outage Management System communications, enabled two-way end-user communication and information flow, and the integration of distributed energy resources; allowing for a greater role of renewable energy generation into grid operations.

Smart grid technologies are distinguished by how they improve the performance of the electric system. Each is associated with, or enables, Smart Grid and Energy Storage Functions that change in some (or several) aspects of the physical operation of the system that reduces utility costs, confers identifiable benefits to consumers or society, or all three. Evaluation of an individual smart grid or energy storage function requires establishing linkages between the deployment and operation of the technology and the impacts that are anticipated to result. When multiple technologies are deployed together, the team will, to the extent practical, isolate and assign the observed impacts to the individual technology.

The benefits will be evaluated using the DOE-specified four major benefit categories: (1) Economic, (2) Reliability, (3) Environmental, and (4) Security. Table 2-5 indicates the benefits KCP&L anticipates will be observed during the course of the project for each of the individual technologies that will be implemented. These technology/benefit linkages manifest KCP&L's initial project design objectives. These technologies were chosen because they have the possibility of providing extensive system benefits, individually, and collectively, they offer an even more effective means for achieving the smart grid objectives.

2.1.4.2 SmartGrid Project Metrics Reporting

The Department of Energy (DOE) requires all Smart Grid Demonstration Projects to report baseline, build, impact, and other metrics, along with Technology Performance Reports (TPR). KCP&L will report all applicable Build and Impact Metrics and TPRs for the KCP&L Green Impact Zone SmartGrid Demonstration according to the schedule shown in Table 2-6. Metrics reports will be submitted 30 days after the completion of a reporting period. For example, the first Build Metrics report is designated for Q2 of 2011; it will be submitted on or before July 30, 2011. Interim TPRs will be submitted annually before the end of calendar years 2012, 2013, and 2014. The Final Project Technical Report is due April 30, 2015 (90 days after the contract completion date).

Table 2-5: Smart Grid Benefits for KCP&L's Demonstration Project

Benefit Category	Benefit	Beneficiary	Provided by Project?	Remarks/Estimates
Economic	Arbitrage Revenue*	Consumer	NO	
	Capacity Revenue*	Consumer	NO	
	Ancillary Service *	Consumer	NO	
	Optimized Generator Operation	Utility	MAYBE	The impact of demand response may not impact the generation profile, but KCP&L will investigate if there are benefits.
	Deferred Generation Capacity Investments	Utility	MAYBE	Information will be collected for these benefits, however it has not been determined if these benefits will be demonstrated. Benefits will be highly dependent upon the number of customers enrolling in demand response or dynamic pricing programs.
	Reduced Ancillary Service Cost	Utility	MAYBE	
	Reduced Congestion Cost	Utility	MAYBE	
	Deferred Transmission Capacity Investments	Utility	MAYBE	Analysis will be performed by the KCP&L planning group to determine if the peak demand and energy conservation benefits will offset the need for proposed transmission and substation projects.
	Deferred Distribution Capacity Investments	Utility	YES	
	Reduced Equipment Failures	Utility	YES	The 2yr Project operational/monitoring is relatively short period to measure technology upgrade impacts on these benefit categories.
	Reduced Distribution Equipment Maintenance Cost	Utility	YES	
	Reduced Distribution Operations Cost	Utility	YES	
	Reduced Meter Reading Cost	Utility	YES	
	Reduced Electricity Theft	Utility	YES	
	Reduced Electricity Losses	Utility	YES	
	Reduced Electricity Cost	Consumer	YES	
	Reduced Electricity Cost*	Utility	YES	Based on cycling operation of grid connected battery
Reliability	Reduced Sustained Outages	Consumer	YES	
	Reduced Major Outages	Consumer	MAYBE	Based on asset monitoring and FISR
	Reduced Restoration Cost	Utility	YES	
	Reduced Momentary Outages	Consumer	MAYBE	PQ will be monitored, but it has not been determined if the proposed corrective action plan will reduce the number of momentary outages.
	Reduced Sags and Swells	Consumer	YES	
Environ-mental	Reduced carbon dioxide Emissions	Society	YES	
	Reduced SO_X, NO_X, and PM-10 Emissions	Society	YES	
Energy Security	Reduced Oil Usage	Society	YES	
	Reduced Wide-scale Blackouts	Society	NO	Demonstration project does not include any wide-area or transmission SmartGrid components.

Table 2-6: Build/Impact Metrics and TPR Reporting Schedule

	2011				2012				2013				2014			
Report	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Build Metrics		X	X	X	X	X	X	X	X	X	X	X				
Impact Metrics			X		X		X		X		X		X		X	
Interim TPRs								X				X				X
Final TPR/Draft FTR*																X*

* The Final TPR will be issued as a Draft Final Technical Report March 31, 2015. The final Technical Report, will be submitted by April 30, 2015 (90 days after contract completion)

This section describes the Baseline, Build and Impact Metrics that KCP&L will report to the DOE. The metrics apply to the total project supported by the DOE and KCP&L cost-shared funds. Baseline, Build, and Impact Metrics are detailed in Appendix A Each table lists the metrics which are applicable to this project, indicates the measurement units associated with the metric, and any notes.

2.1.4.3 Build Metrics – Measurement of Smart Grid Progress

KCP&L will report both project and system Build Metrics throughout the project for those Build Metrics listed. Project Build Metrics pertain to only those assets deployed by and funded by this Project. System Build Metrics pertain to all assets deployed on the KCP&L system, including Project assets.

The DOE developed a framework for reporting project Build metrics that organizes the reporting into five categories: Monetary Investments; Electricity Infrastructure Assets; Policies and Programs; Job Creation; and Marketplace Innovation. The following subsections present the build metrics that will be reported for the KCP&L SGDP.

2.1.4.3.1 Electricity Infrastructure Asset Metrics

The Baseline and Build Metrics KCP&L will report for the Distribution infrastructure assets funded by the ARRA and cost share are contained in Appendix A. KCP&L will report the system metrics for the applicable smart grid assets that are already in place or will be deployed using non-DOE award funding during the reporting period. Baseline and Build Metrics will be reported for the following assets classifications deployed in the KCP&L Green Impact Zone SGDP:

- AMI Assets
- Customer Systems Assets
- Electric Distribution Assets
- Distributed Energy Resources

2.1.4.3.2 Policies and Programs

The Baseline and Build Metrics KCP&L will report for KCP&L's pricing programs funded by the ARRA and cost share are contained in Appendix A. KCP&L will report the system metrics for the applicable smart grid programs that are already in place or will be deployed using non-DOE award funding during the reporting period. Baseline and Build Metrics will be reported in the following table:

- KCP&L's Pricing Programs

2.1.4.3.3 Job Creation Reporting

KCP&L will track and report the number and types of jobs by labor category and SGDP project classification, quarterly. In coordination with the DOE, jobs created and retained will be reported using the appropriate DOE full-time equivalents (FTEs) calculation, resulting from both ARRA funding as well as KCP&L's cost-share funds.

2.1.4.3.4 Monetary Investment Reporting

KCP&L will report funds that have been expended for the deployment of the SGDP, quarterly. The report will include the DOE awards and the cost share of all recipients. KCP&L will report investments related to the cumulative installed cost of equipment once the assets are deployed and considered utility assets. Investments metrics that will be reported by KCP&L are highlighted in Table 2-7 below. Financial analysts will utilize the KCP&L Financials System to determine or estimate the monetary investments related to the installation of equipment. KCP&L expects to develop estimates for project management and oversight related to equipment installation, testing, and commissioning, and apply those estimates to each category of investments as assets are installed.

Table 2-7: Applicable Monetary Investment Build Metrics ($000)

AMI				Customer Systems					
Monetary Investment	AMI Back Office Systems	Communication Equipment	AMI Smart Meters	Customer Back Office Systems	Customer Web Portals	In-Home Display	Smart Appliances	Programmable Controllable Thermostats	Participating Load Control Device
ARRA	-	-	-	-	-	-	-	-	-
Cost Share	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-
Other Assets and Costs that do not align with the categories listed above:									
Electric Distribution									
Monetary Investment	Back Office Systems	Distribution Management System	Communications Equipment/SCADA	Feeder Monitor/Indicator	Substation Monitor	Automated Feeder Switches	Capacitor Automation Equipment	Regulator Automation Equipment	Fault Current Limiter
ARRA	-	-	-	-	-	-	-	-	-
Cost Share	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-
Other Assets and Costs that do not align with the categories listed above:									
Electric Distribution – Distributed Energy Resources (DER)									
Monetary Investment	DER Interface/Control Systems	Communication Equipment	DER/DG Interconnection Equipment	Distributed Generation (DG)	Renewable DER	Stationary Electricity Storage	Plug-in Electric Vehicles	Plug-in Electric Charge Stations	
ARRA	-	-	-	-	-	-	-	-	
Cost Share	-	-	-	-	-	-	-	-	
Total	-	-	-	-	-	-	-	-	
Other Assets and Costs that do not align with the categories listed above:									

2.1.4.3.5 Market Place Innovation Reporting

Based upon the review of the project proposal and discussions with the DOE, KCP&L does not believe the Marketplace Innovation Build Metric pertains to this SGDP. Marketplace Innovation will not be tracked and reported, but the SGDP will potentially create additional markets and opportunities that KCP&L and its project partners can pursue.

- The customer facing SmartGrid technologies demonstrated will open the door to an abundance of new products and services that will better allow customers to monitor and manage their energy consumption.
- The next-generation grid management technologies and interoperability demonstrated will provide new SmartGrid products and services that project partners can take to the market furthering the ability of utilities to more economically evolve a more robust SmartGrid.

2.1.4.4 Impact Metrics – Measurement of Smart Grid Impacts

In order to measure, evaluate, and report the performance of smart grid technologies implemented through this project, KCP&L will prepare and submit Impact Metrics Reports semi-annually, in accordance with the schedule in Table 2-6. Impact Metrics will consist of measured or calculated characteristics of the functioning smart grid system throughout the project contractual period. These metrics will enable trending and evaluation of technologies on an aggregate level by the DOE. Impact Metrics to be reported are described in Appendix A according to the following classifications.

- AMI and Customer Systems
- Electric Distribution Systems
- Battery Energy Storage System

Depending on the Impact Metric to be reported and the availability of data, KCP&L will report either a directly-observed project Impact Metric on project-only assets or will report system level impacts. Since this project affects only a small portion of the KCP&L service territory and customers, noticeable impacts are not expected at the system level. However, system level data may be used to estimate project level metrics.

2.1.4.5 Demonstration Subprojects and Expected Benefits

The KCP&L SGDP includes various smart grid technologies that will be integrated and operated through advanced automation and interfacing of back office systems. The primary project objective is to demonstrate interoperability of these diverse systems and capabilities. As permitted, the KCP&L SGDP will evaluate the performance of and benefits from the implementation of each individual subprojects.

The SmartSubstation subproject is intended to enable the following benefits:

- Improved real-time operating data on critical substation equipment will be provided that will lower operating costs and improve reliability
- O&M cost of relay maintenance will be reduced
- Distribution automation will be enabled through the substation controller which leads to reduced outage time and improved reliability to the consumer

The SmartDistribution subproject implementation is intended to enable the following benefits:

- Improved service reliability by reducing the frequency and duration of sustained outages
- Reduced frequency of momentary outages
- Reduced operational expenses as many functions will occur automatically without human intervention or be performed remotely without a field crew
- Reduced maintenance expenses by providing rich data to enable predictive and proactive maintenance strategies

The SmartGeneration subproject is intended to enable the following benefits:

- Improve general or localized reliability through grid-connected storage and load management
- Demand reduction on circuits equipped with DER/Solar/Battery

The Smart DR/DER Management subproject is intended to enable the following benefits:

- Reduce customer load during DR events through DERM execution of DR devices and programs
- Reduced circuit/feeder load through select execution of demand response
- Defer investments in generation and transmission/distribution assets

The SmartMetering subproject is intended to enable the following benefits:

- Improved frequency of meter reads and flexibility of read scheduling by enabling customers to select dates for turn on/turn off requests without associated field visits
- Improved accuracy of meter inventory and reduction in untracked meters
- Increased percentage of automated reads and reduced amount of stale reading within the existing automated one-way meter reading system
- Increased percentage of near real-time outage notifications and power restoration that would be supplied by a two-way metering system
- Ability to monitor power quality at the customer service entrance
- Provided real-time, two-way communication for DR program control initiation and verification of program participation

The SmartEnd-Use subproject is intended to enable the following benefits:

- Reduced peak demand
- Reduced energy consumption
- Improved customer engagement and participation in DR programs

2.1.4.6 Smart Grid and Energy Storage Functions and Benefits

The KCP&L SGDP has been divided into five subprojects to demonstrate the expected benefits described in the previous section. Details of each subproject are described above in Section 2.1.4.5. During Phase 2 (Project Administration and Detailed Design) of the project, the KCP&L SmartGrid Demonstration Team performed a detailed review of the SGDP technologies being implemented and identified the DOE defined SmartGrid and Energy Storage Functions that will be demonstrated within the scope of the project. Table 2-8 lists the Smart Grid Functions to be demonstrated and analyzed by subproject.

Table 2-8: Smart Grid Functions by KCP&L Demonstration Subproject

Smart Grid Functions D = Direct S = Support		Demonstration Subproject: Smart Metering	Smart End-Use	Smart Substation	Smart Distribution	Smart Generation
Smart Grid Functions	Fault Current Limiting					
	Wide Area Monitoring, Visualization, and Control					
	Dynamic Capability Rating					
	Power Flow Control					
	Adaptive Protection					
	Automated Feeder Switching			S	**D**	
	Automated Islanding and Reconnection			S	S	**D**
	Automated Voltage and VAR control			**D**	**D**	
	Diagnosis and Notification of Equipment Condition			**D**	**D**	
	Enhanced Fault Protection					
	Real-Time Load Measurement and Management	**D**				
	Real-Time Load Transfer				**D**	
	Customer Electricity Use Optimization	**D**	**D**			
	Distributed Production of Electricity					**D**
	Storing Electricity for Later Use					**D**

Each SGDP subproject will support one or more SmartGrid or Energy Storage Functions and in many cases a SmartGrid or Energy Storage function will require the integration of technologies multiple subprojects. Operational Test Plans have been developed for each applicable SmartGrid and Energy Storage functions are described in Section 2.4 later in this document. These Operational Test Plans establish linkages between the deployment of the technologies and changes in the performance of the electric system and detail the operational testing steps, data to be collected, anticipated benefits, and outline the analysis to be performed.

Smart grid benefits identified in Table 2-5 are realized by each Smart Grid Function according to the matrix presented in Table 2-9 below.

2.1.4.7 Data Gathering and Benefit Quantification

Impact metric reporting and benefit quantification for the SGDP will be accomplished through a variety of different tools and methods. This Project is diverse and will implement numerous smart grid technologies and applications that will need to be evaluated in different ways. Benefits associated with changes to how energy is used on the KCP&L system will be evaluated through the capture and analysis of detailed interval usage data for all customers, circuits/feeders, and necessary equipment within the project area. Benefits associated with operational efficiency will be evaluated through detailed operational and automated event tracking contained within the various systems to be implemented.

Table 2-9: Smart Grid Benefits Realized by SmartGrid Functions

Smart Grid Benefits D = Direct Benefit I = Indirect Benefit		Smart Grid Function: Automated Voltage & VAR Control	Real-Time Load Transfer	Automated Feeder & Line Switching	Automated Islanding & Reconnection	Diagnosis &Notification of Equipment Condition	Real-Time Load Measurement & Management	Customer Electricity Use Optimization	Distributed Production of Electricity	Storing Electricity for Later Use
Economic	Arbitrage Revenue*									
	Capacity Revenue*									
	Ancillary Services Revenue*									
	Optimized Generator Operation									
	Deferred Gen. Capacity Investments							D	D	D
	Reduced Ancillary Service Cost									
	Reduced Congestion Cost									
	Deferred Trans. Capacity Investments									
	Deferred Dist. Capacity Investments		D				I	D	D	D
	Reduced Equipment Failures					I				
	Reduced Dist. Equip. O&M Cost									
	Reduced Distribution Operations Cost			D						
	Reduced Meter Reading Cost						D			
	Reduced Electricity Theft						D			
	Reduced Electricity Losses	D	D				I	I	D	D
	Reduced Electricity Cost							D	D	D
Reliability	Reduced Sustained Outages			D	D	I	D		I	D
	Reduced Major Outages		D		D		D			
	Reduced Restoration Cost			D		I	D			
	Reduced Momentary Outages									
	Reduced Sags and Swells									
Environmental	Reduced carbon dioxide Emissions	I	I	I			I	I	I	I
	Reduced Emissions (SO_X, NO_X, PM-2.5)	I	I	I			I	I	I	I
Energy Security	Reduced Oil Usage			D			D		I	
	Reduced Wide-scale Blackouts									

*These benefits are only applicable to energy storage demonstrations.

Interval and historical daily meter data for circuits and customers within the SmartGrid Demonstration area will be accessed through KCP&L's DMAT. This web-based database will enable filtration and selection of relevant meter data that may then be extracted and aggregated for load profile generation. All accounts within the Project area will be tagged with relevant demographic information for efficient and accurate filtration. Load profile generation, weather normalization, and comparative analysis will be accomplished through the use of computational spreadsheet software such as Microsoft Excel.

Operational metrics such as the tracking of events for specific incidents on specific equipment will be recorded by the appropriate management system:

- Manual activities executed will be tracked by the Mobile Workforce Management System
- Automated substation and distribution circuit activities executed will be tracked by the DMS/DCADA
- Various equipment failures and subsequent automated actions will be tracked by the DMS/DCADA
- Outages tracked by the OMS
- Compliance in DR events will be tracked by the HEMP
- AMI performance by the AMI Head-end and MDM system
- Grid-connected battery performance will be tracked through AMI metering, the inverter and switchgear control system, and the battery data acquisition system

Usage and operational data will be gathered in accordance with the Operational Test Plans in Section 2.4 for each Smart Grid Function. KCP&L will then report data and impact metrics to the DOE as required. In addition, KCP&L will attempt to quantify benefits associated with each Smart Grid Function in accordance with Section 2.5. Benefit quantification will be focused on assessing the potential impact of each Smart Grid Function on the KCP&L system. For example, KCP&L will attempt to quantify the amount of demand reduction that is achieved by each demand response technology deployed by comparing the hourly load profiles of each group during demand response events with weather-adjusted hourly load profiles of the same group from a previous day. Impacts to overall energy usage will be quantified through comparisons of daily, monthly, and annual load profiles of participant groups with those of control groups for the same time period. Impacts to operations and reliability will be quantified by comparing numbers of experienced events to forecasted events based on historical data. System average costs will then be applied to events reduced or increased.

2.1.4.8 Baseline Data for Impact Metrics and Benefits Assessment

The KCP&L Green Impact Zone SmartGrid Demonstration will demonstrate many diverse smart grid technologies. Each application of those technologies will provide different benefits which will need to be compared to appropriate baseline data. Therefore, multiple baseline development methodologies will be required for of each impact metric within the project.

2.1.4.8.1 Historical Baseline Data

KCP&L will collect and report historical usage and system performance data on customers and assets within the Project area:

- Historical usage data will consist of daily kWh readings, beginning February, 2010, as collected by the KCP&L AMR system for all customers within the SGDP area. Additionally, KCP&L has initiated 15 minute interval usage reading on approximately 6,000 customers within the project area, the maximum allowed by the system, beginning July, 2010.
- AMI and interval metering will be near fully deployed by March, 2011, providing additional interval data on all customers within the SGDP area prior to the project observation period scheduled to begin in July, 2012.
- System performance data on the assets affected by smart grid technology deployment will consist of five years of operational statistics such as SAIDI, SAIFI, MAIFI, CAIDI, and known incidents and outage events.

Interval data for all customers within the SGDP area will be collected through the AMI system throughout the duration of the project and will be reported to the DOE at each reporting milestone (semi-annually) in the form of hourly usage data grouped by customer class and sub-class. In some cases, this data may be utilized to generate historical baselines by which to compare project usage data.

2.1.4.8.2 Baseline Methodology for Automated Operations

Some smart grid applications will automate operational activities that were previously accomplished manually. For these applications, baseline data will consist of a forecast of estimated manual activities that KCP&L expects would have occurred on the applicable assets if smart grid technologies were not implemented. These forecasted estimations will be based on historical manual activity information available within KCP&L's historical records, specific to the relevant assets within the project area. Actual automated and manual actions that occur within the project area and during the project period will be recorded and compared to these baselines.

2.1.4.8.3 Baseline Methodology for Reduced Event Occurrence

Some smart grid applications will reduce distribution system equipment failures through monitoring and automated switching. For these applications, baseline data will consist of a forecast of estimated failure events that KCP&L expects would have occurred on the applicable assets if smart grid technologies were not implemented. These forecasted estimations will be based on historical failure event information available within KCP&L's historical records and outage management system, specific to the relevant assets within the project area. Actual monitoring and subsequent avoidance activities will be recorded and compared to these baselines.

2.1.4.8.4 Baseline Methodology for Changes to Energy Consumption

Some smart grid applications will reduce overall energy consumption on the system or enable enhanced customer information that will empower customers to control and conserve energy consumption. These impacts occur continuously and are not isolated to discreet events. For these applications, baseline data will consist of hourly, daily, and monthly load profiles for control groups of similar customers that do not have access to or choose not to participate in the relevant smart grid technology and information. Control group load profiles will cover the entire project duration and the data will be acquired through the existing AMR and newly deployed AMI and MDM systems that KCP&L is implementing as part of this project for all customers within the project area. Impacts of these energy conservation applications will be contained in required periodic reports to the DOE under the customer hourly load metrics for various customer classes and sub-classes.

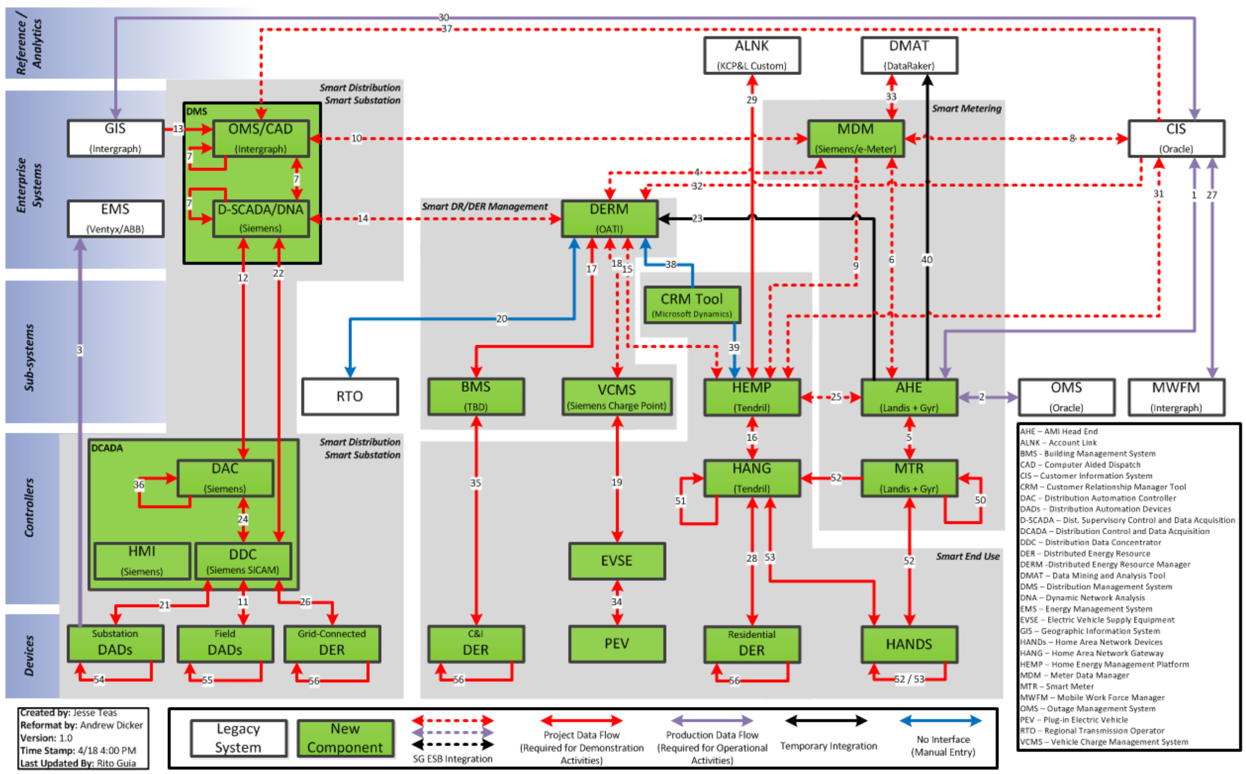
2.1.4.8.5 Baseline Methodology for Demand Response Events

Other smart grid applications will reduce system peak load and energy consumption during scheduled and discreet events to accomplish temporary system, circuit, or customer demand reduction. Demand reductions may be executed for either economic value (sold into capacity markets) or to improve system performance and reliability (relieve distribution system congestion). For these applications, event baseline data for evaluation will consist of weather-normalized hourly load profiles for applicable equipment and event participants from either a previous similar day or from a proxy day or a control group. Baseline load profiles will be calculated as hourly average load for applicable equipment, assets, and groups of smart grid technology participants for each demand reduction event. Actual average load profiles for day of an event will be compared to the baseline load profiles. Demand response impact analysis results for events associated with this project will be summarized in technical performance reports to the DOE.

2.2 Systems Implementation

The KCP&L SGDP is based on deploying an integrated end-to-end solution, illustrated in Figure 2-17 below, that demonstrates interoperability across the five (5) SmartGrid subproject components that included eight (8) major new back office distribution control, systems (AMI, MDM, HEMP, DMS, OMS, D-SCADA, DERM, & VCMS), five (5) existing legacy back office systems (CIS, ALNK, DMAT, GIS, & OMS) and numerous substation and field automation controllers. The implementation of these systems is summarized in the following sections.

Figure 2-17: KCP&L SmartGrid Demonstration Systems Integration



The implementation of the SGDP systems was carried out using a disciplined project management approach, through a collaborative effort between leadership and cross-functional and individual subproject implementation teams. The SmartGrid Demonstration Leadership was provided by members of a Partner Leadership Team, Program Director, and members of the KCP&L Executive Advisory Team. The KCP&L SGDP Management Plan [17] [18] [19] [20] that was approved by the DOE and revised annually by the project PMO staff.

Each cross-functional and subproject had an assigned lead that reported to the Program Management Director. Each subproject implementation team was required to utilize a disciplined project management approach to provide integration into the overall program management responsibilities and deliverables. The Program Director provided project management requirements, guidance, oversight and had overall responsibility for the direction and performance of the project. The Program Management Director, PMO staff, and Implementation Team Leads provided periodic updates to the Partner Leadership Team and the KCP&L Executive Advisory Team.

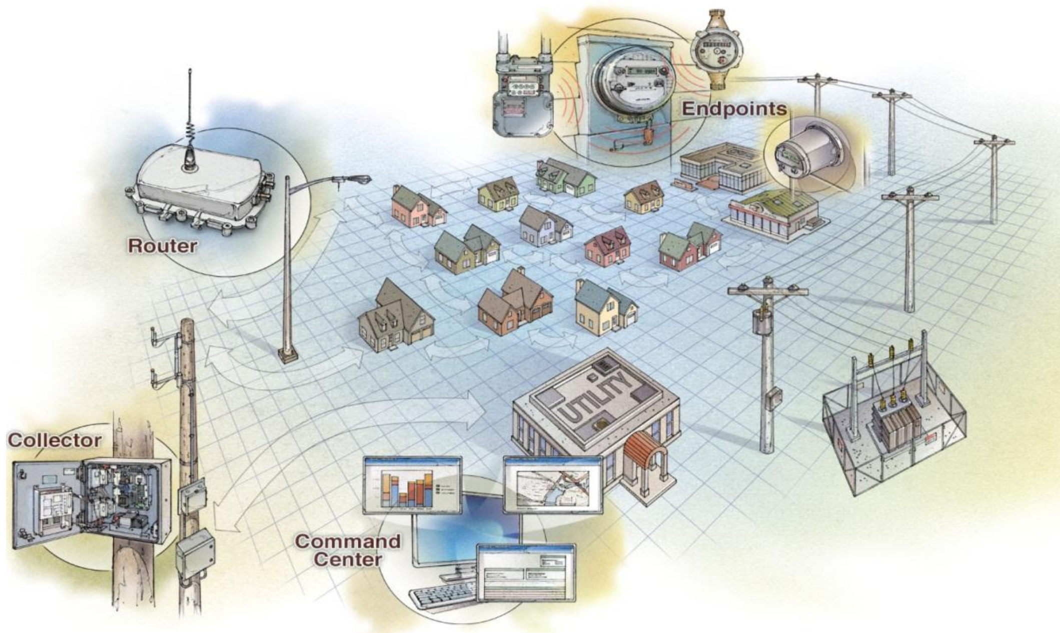
2.2.1 SmartMetering

The SmartMetering subproject deployed a state-of-the art integrated AMI and MDM solution. The following subsections summarize these system implementations.

2.2.1.1 Advanced Metering Infrastructure

Figure 2-18 illustrates the Landis+Gyr Gridstream AMI system and FAN infrastructure components implemented as part of the SmartMetering subproject.

Figure 2-18: L+G Gridstream AMI Command Center and FAN



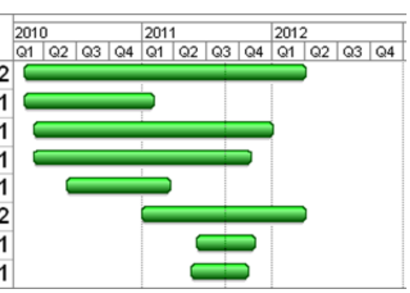
2.2.1.1.1 Build

The KCP&L Demonstration AMI System was deployed over an approximately nine month period beginning in October, 2010 and ending in June, 2011. The implementation consisted of the deployment of smart meters to all customers within the project area, installation of an AMI Head-End (Command Center) to manage information traffic and meter endpoint registration, the deployment of a wireless communication network to connect meter endpoints to the AMI Head-End, and the integration of the AMI Head-End to KCP&L back office systems.

The KCP&L Demonstration AMI System network and endpoints were deployed over approximately a nine month period with additional project planning and software maintenance activities stretching the entire project out to approximately two years as is shown in Figure 2-19.

Figure 2-19: KCP&L SmartGrid Demonstration Project AMI Deployment Timeline

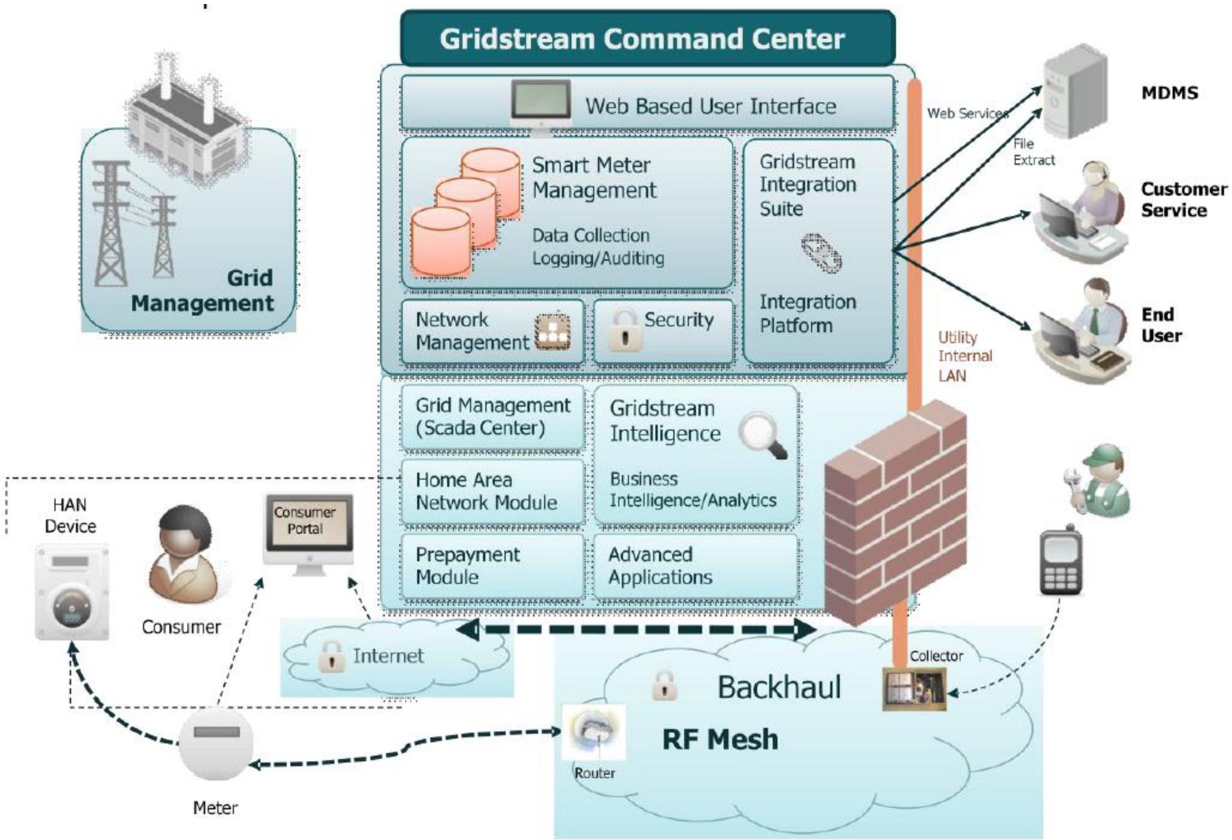
Task Name	Start	Finish
SmartMetering Implementation	Mon 2/1/10	Fri 3/30/12
SmartMeter Partner Project Management	Mon 2/1/10	Mon 1/31/11
SmartMetering Project Planning	Tue 3/2/10	Fri 12/30/11
SmartMetering Project Design/Development	Mon 3/1/10	Mon 10/31/11
SmartMetering Deployment	Tue 6/1/10	Fri 3/18/11
SmartMetering System Acceptance	Mon 12/27/10	Fri 3/30/12
Prepare SmartMetering Implementation Report	Wed 6/1/11	Fri 11/11/11
Command Center (AMI Headend) Upgrades	Mon 5/16/11	Fri 10/21/11



2.2.1.1.1.1 Hosted AMI Head-End Solution

KCP&L chose to implement the Gridstream AMI Head-End system, Figure 2-20, as a managed-service and hosted-platform, with Landis+Gyr hosting the backend servers and systems and capturing meter reads to meet contractual performance criteria.

Figure 2-20: AMI Head End - L+G Gridstream Command Center



For the demonstration development/lab environment, KCP&L implemented the Gridstream AMI head-end internally within the KCP&L internal systems development infrastructure to facilitate the application, web, and external integration needs of the lab AHE and other systems.

An AMI lab was built-out in KCP&L facilities featuring AMI collectors, routers, and over 25 meters associated to development CIS accounts to emulate real-life customer meters. This lab was used to test all aspects of AMI from a project-perspective, including system-to-system integration, AHE-to-SmartMeter testing, and SmartMeter-to-HAN device testing.

2.2.1.1.1.2 AMI RF Network Build-Out

KCP&L used internal construction crews, assisted by L+G personnel, to deploy the communications network. Collectors, illustrated in Figure 2-21, were installed at the Midtown Substation in the SGDP area and on a transmission pole near the future site of a new substation just north of the area. One collector communicates via a fiber-based network and the other via a wireless network. Landis+Gyr provided an optimized network installation guide for the routers within the FAN. Routers were installed on distribution feeder poles where possible.

Figure 2-21 Installed AMI FAN Infrastructure

2.2.1.1.1.3 AMI Meter Exchange

SmartMeter installers for the project were hired through a third party from the SGDP area. This was in line with KCP&L's commitment to hire and train local labor as one of the overarching themes of the Green Impact Zone. These employees were given training on basic electricity, proper residential metering configuration, meter exchange procedures, workplace safety, and customer service. KCP&L journeymen meter technicians deployed all 3-phase meters in the SGDP area due to their expertise and high level of safety awareness.

Meter reading routes were selected for the determined project geographic area. Prior to implementation, KCP&L conducted a route audit to check for safety concerns, determine accessibility issues, identify non-standard and A-base meter enclosures, and identify potential customer concerns. During KCP&L's previous Automated Meter Reading (AMR) deployment, A-base meter sockets were used to retrofit many legacy meter types housed within meter enclosures. Minor safety issues (e.g. meter seals missing, diversion issues, etc.) were identified and corrected prior to beginning the installation of SmartMeters.

Through pre-deployment testing, KCP&L Measurement Technology staff determined that the greater physical depth of the SmartMeter would not allow the meter enclosure cover to close properly on many of these installations. KCP&L contracted with Milbank, a local Kansas City meter socket manufacturer, to design and construct modified covers for those legacy meter enclosures.

Meters were installed according to sequential routes established by KCP&L. Installers used hand held computer devices to record old meter numbers and readings, latitude/longitude of each smart meter service point, and a picture of both the old and new meters. All new meter identification information was captured and data was uploaded and sent to KCP&L electronically at the end of each day of installation. This helped ensure data transfer was accurate and the pictures assisted in investigations and resolutions of issues that arose.

2.2.1.1.2 Integration

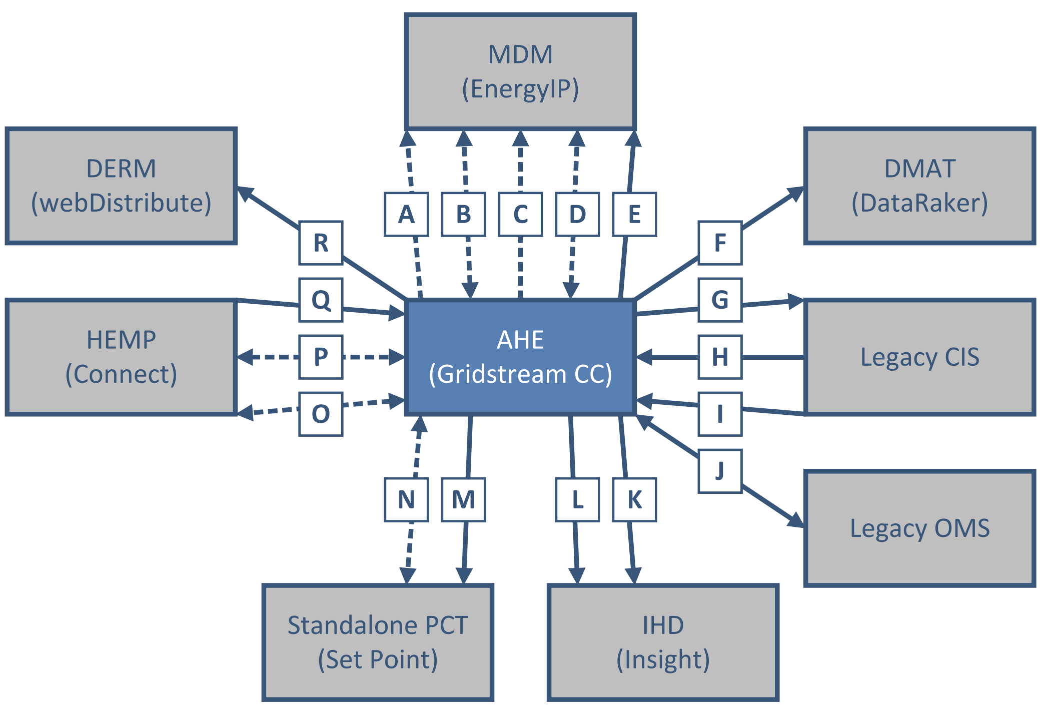
KCP&L utilized use case development to define the AMI system functionality and system-to-system integration requirements early on in the design process. These use cases help define scenarios to be addressed and the systems that are involved, the standards used for the interfaces between systems, and the message formats and payloads required for these interfaces to achieve these scenarios successfully.

KCP&L chose a two-phase approach to the AMI integration implementation. The first phase included point-to-point interfaces between the AHE, the Legacy CIS, the Legacy OMS, and the HEMP to ensure a quick, but functional initial system stand-up. This first phase utilized existing legacy interfaces that were already being used by the Legacy AMR system in an effort to reduce impact on KCP&L Production systems and processes, such as billing in the Legacy CIS and outage/restoration analysis in the Legacy OMS.

The second phase focused on standing-up new SmartGrid interfaces between the AHE and other SmartGrid systems, including the MDM, HEMP, and DERM, utilizing an Enterprise Service Bus (ESB) approach for message routing and transformations. This approach is an alternative to point-to-point interfaces and provides KCP&L greater flexibility in control of message routing and system interfaces by bringing all transactions in-house and removing direct interfaces between systems.

An overview of AHE system-to-system interfaces and applicable messages is illustrated in Figure 2-22.

Figure 2-22: KCP&L SmartGrid Demonstration Project AHE Integration



The integration touch points for the AMI are as follows:

A. Outage/Restoration Event notification initiated from SmartMeters to MDM and sent from MDM to OMS. This is an IEC 61968 CIM-formatted event message used to notify MDM (and OMS) of an outage or restoration event occurring at a SmartMeter.

B. Power Status Verification request-reply initiated from OMS to MDM and sent from MDM to AHE in the form of an On-Demand Read request-reply. This is an IEC 61968 CIM-formatted request-reply used to verify power status (On, Unknown, or Service Disconnected) at a target SmartMeter.

C. General Event notification initiated from AHE to MDM. This is an IEC 61968 CIM-formatted event message used to notify MDM of various MDM-supported events (using the corresponding CIP 4-part IDs) that occur within the AMI system. MDM can then log these events and/or route them to other subscribing systems.

D. Remote Service Order request-reply messages, including On-Demand Read and Remote Service Connect/Disconnect, initiated from CIS to MDM and sent from MDM to AHE. These are IEC 61968 CIM-formatted request-reply messages used to get on-demand reads and execute remote service connect/disconnects on eligible target SmartMeters.

E. Daily Register and Interval Read data initiated from AHE to MDM. This is California Metering Exchange Protocol (CMEP)-formatted data sent hourly to be stored in the meter usage data repository and used for TOU billing determinants.

F. Daily Register and Interval Read data initiated from AHE to DMAT. This is CMEP-formatted data sent daily to be used for load research.

G. Daily Register and Interval Read data initiated from AHE to CIS via a middleware database. This is CMEP-formatted data sent daily to be used for billing determinants.

H. Database Maintenance (DBMAINT) process messages and integration calls initiated from the CIS DBMAINT process. This DBMAINT process is used to keep CIS and AHE in-sync for customer records, service connectivity, and meter deployment/exchange purposes.

I. Estimated Bill True-Up and Consumption Pricing messages initiated from CIS to AHE. These daily notifications are used to update estimated bill true-up information on customer IHDs and consumption pricing information on customer IHDs and Stand-alone PCTs.

J. Power Outage Analysis (POA) messages initiated from AHE to Legacy OMS and Restoration Verification Analysis (RVA) messages initiated from Legacy OMS to AHE. These are MultiSpeak-formatted messages used for outage and restoration analysis within Legacy OMS.

K. Estimated Bill True-Up messages initiated from AHE to IHDs. These “tunnel text messages” are ZigBee SEP 1.0-formatted messages sent daily to update customer IHDs with up-to-date estimated billing information.

L. Consumption Pricing messages initiated from AHE to IHDs. These “tunnel text messages” are ZigBee SEP 1.0-formatted messages sent daily to update customer IHDs with pricing so the IHD can display real-time consumption cost information.

M. Consumption Pricing messages initiated from AHE to Stand-alone PCTs. These “tunnel text messages” are ZigBee SEP 1.0-formatted messages sent daily to update the PCT with pricing information.

N. Demand Response Event requests initiated from AHE to AMI-based DR assets (Stand-alone PCTs for this project) via SmartMeters, and Event Opt-Out/Opt-In replies initiated from AMI-based DR assets to AHE via SmartMeters. These are ZigBee SEP 1.0 -formatted request-reply messages used to notify AMI-based DR assets of creation, modification, or cancellation of impending DR events and to notify AHE of AMI-based DR asset event participation status.

O. Get Device Info request-reply initiated from HEMP to AHE. This is an IEC 61968 CIM-formatted request-reply used to gather HAN device information for AMI-based DR assets (Stand-alone PCTs).

P. Demand Response Event request initiated from HEMP to AHE, and Event Opt-Out/Opt-In reply initiated from AMI-based DR assets (Stand-alone PCTs for this project) to HEMP. These are IEC 61968 CIM-formatted request-reply messages used to notify AMI-based DR assets of creation, modification, or cancellation of impending DR events and to notify HEMP of AMI-based DR asset event participation status.

Q. Consumption Pricing and Billing True-Up messages initiated from HEMP to AHE. These "tunnel text messages" are sent daily to update customer IHDs with real-time per-kWh consumption pricing information and up-to-date estimated billing information.

R. Daily Register and Interval Read data initiated from AHE to DERM. This is CMEP-formatted data sent daily to be used for customer load profile baselines within DERM.

2.2.1.1.3 Post-Implementation Operational Issues

Throughout the SGDP, numerous upgrades to the AMI system and SmartMeters were executed to add support for project-necessary functionalities and increase overall performance of the AMI system as a whole. The upgrades were performed on an as-needed basis, with careful planning and scheduling in an effort to reduce impacts on AMI performance and system-to-system interfaces, and were first tested in the Development environment to verify the upgrades prior to moving them to Production.

- Command Center 5.0 Upgrade – As the first major functionality-based upgrade, the move to Command Center 5.0 included many key components that are functionality cornerstones of AMI portion of the SGDP. Security improvements implemented core security requirements for the AMI implementation including security configuration tokens, RF traffic encryption keys, and AMI system security modes with varying degrees of security. The upgrade added support for CIM-compliant meter event messages to further simplify system-to-system integration. Furthermore, CIM-based interfaces for on-demand meter reading, meter disconnect/reconnect, and bulk meter reading were added to the AMI system integration core. This upgrade was performed in the summer of 2011.
- Command Center 5.1 Upgrade – Primarily, the Command Center 5.1 upgrade added the much-needed benefit RF broadcast commands. This functionality allows for commands, meter programs, and firmware upgrades to be sent to large groups of meter based on meter type, firmware versions, and other criteria, as opposed to the having to leverage commands sent to meters one-by-one or to predefined groups of meters. This significantly reduced the time and manual effort required to execute meter program updates and firmware upgrades to large groups of SmartMeters.

  Added support for new peripheral software aimed to improve performance and integration with other SmartGrid systems. Additionally, performance-tuning within the back office server software and RF collector, router, and endpoint firmware helped improve latency issues that were seen on previous releases. This upgrade was performed in the fall of 2011.
- Command Center 5.6 Upgrade – On the performance side, the Command Center 5.6 added support for Oracle 11g to improve load balancing and database performance. Also, the memory utilization within the SmartMeter was improved which helped mitigate potential storage, processing, and communications issues.

  On the end-use side, the improved utilization of memory within the SmartMeter also corrected an issue seen when multiple demand response replies were sent from HAN devices in a short period of time. Support for the Smart Energy Profile 1.1 stack was added enabling the use of added features in SEP 1.1. An interface for third-party DR event processing was also added to enable the AHE to receive DR event requests from external systems and send DR event response back to the requesting systems. This upgrade was performed in the summer of 2012.

- Command Center 5.7 Upgrade – The Command Center 5.7 upgrade brought about additional performance enhancements. These enhancements have the added benefit of improving the AMI system scalability, if needed in the future. This upgraded included RF mesh improvements for more efficient network routing and improved outage and restoration reporting. It also included full 64-bit server support on the back end to improve memory utilization and message queuing from field collectors.

  The upgrade also added support for more CIM-based event messages and updated 4-part IDs for CIM 2.0 compliance. Additionally, CIM-based support was added for Power Status Verification using a modified on-demand read request-reply that can be issued to SmartMeters regardless of the SmartMeters last-known status in the AHE. This upgrade was performed in the spring of 2013.

- Command Center 6.0 Upgrade – The decision to upgrade to Command Center 6.0 was primarily driven by the needs of KCP&L's AMR/AMI Refresh Project that ultimately is an expansion of the AMI system that has been implemented as a part of the SGDP. To facilitate a smooth transition from the Legacy KCP&L AMR system to the newly implemented AMI system, KCP&L is deploying AMR-AMI concentrator node into the AMI RF mesh that will route both AMR and AMI traffic accordingly during the three-year AMR-AMI meter exchange process. This AMR-AMI routing capability is a new functionality for the Gridstream RF mesh, and Command Center 6.0 adds necessary layered-routing support for these new AMR-AMI concentrator.

  In addition, the strict security requirements defined for the SGDP include added security and encryption features that are not included in the Legacy AMR system. Thus, Command Center 6.0 adds the capability to provide both strict security and encryption on the AMI-side while maintaining the more relaxed security on the AMR-side in the new AMR-AMI concentrator nodes. This upgrade was performed in the winter of 2013-2014.

2.2.1.1.4 Lessons Learned

Throughout the build, integration, and daily operation of the AMI system, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- KCP&L had a very successful AMI deployment in terms of customer reaction and satisfaction due to strong and deliberate education effort through grassroots communication paths (goal of 10 touch points prior to installation) and a "white glove" installation approach for GIZ (3300 meters) that included a welcome packet, a knock on the door, and an IHD offer. For the entire SGDP area, each installation included a door knock to inform the customer of their smart meter installation occurrence and to ensure safety of the installer, the customer, and the home. Also, KCP&L met with concerned and objecting AMI customers face-to-face to discuss their concerns. This helped ensure a full deployment of AMI meters to all service points within the project area.
- The choice to select a relatively unskilled workforce resulted in time delays, quality sacrifices, and a reduction in quality and consistency of customer interactions. Additionally, there was a high turnover of that unskilled workforce. Positively, this selection resulted in significant goodwill due to local job creation and local knowledge of the installers.
- A pre-implementation meter audit to identify safety, theft, and non-standard situations was effective and necessary but could have been executed more robustly with increased detail and more organization. This ancillary information could have significantly improved

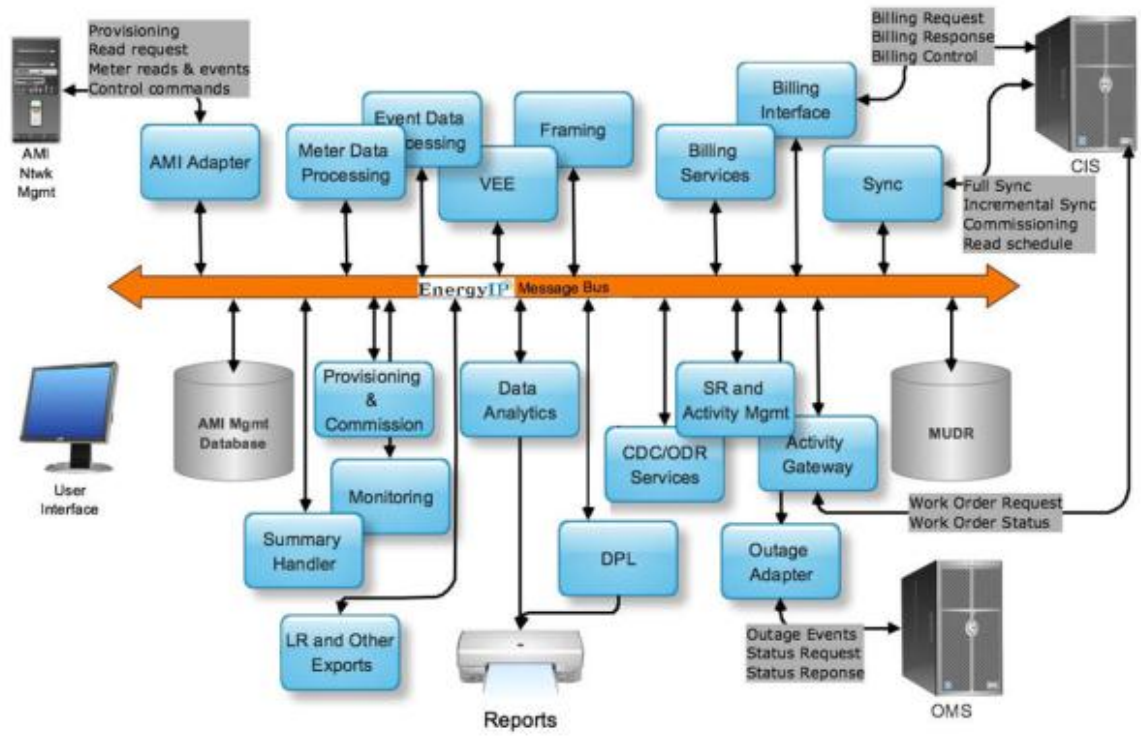
the efficiency of the installation process. For example, non-A-based cans were not accurately identified resulting in wasted trips to premises by installers. FOCUS AX meters cannot be installed in these cans resulting in KCP&L needed to decide if/how to replace cans which are technically owned by the customer.

- The IHD offering in conjunction with meter installation resulted in goodwill but created some technical and user challenges. For example, device installation codes need to be correlated with the proper meter IDs to ensure communications between the IHD and the meter. This requires strict attention to detail when recording codes and meter IDs. Also, the meter-to-device associations need to be made in a timely manner and could have benefited from a more hands-on provisioning process instead of relying on the customer to contact KCP&L support to finish the device pair process.
- Selection of a current vendor partner for AMI resulted in beneficial treatments such as ensured meter quantities despite industry shortage (supply/demand), pre-established relationships with open communications, a local project manager that could react to issues quickly, and meter-to-cash executed very successfully due to vendor knowledge of KCP&L systems, metering, and billing processes.
- Installation of AMI communications hardware, such as collectors and routers, on utility electric service assets helped ensure the hardware received power most or all of the time. Devices were not installed on light poles, as light poles are the last priority for outage restoration.
- Installers used handheld digital devices to capture bar codes of old and new meters at each premise to enable accurate and immediate tracking of installation progress and issues. Unskilled workers struggled to use these devices properly at times, but the devices were still an extreme improvement over manual paper or spreadsheet tracking.
- Expedited timeline and non-sequential deployment process resulted in some oversights regarding software quality assurance and version control issues that resulted in inadvertent disconnects on a small set of customers.
- The importance of clear and frequent communications between the utility and the AMI vendor and the SmartEnd-Use vendors cannot be underestimated. Technology and device references, including device installation codes, must be consistent or robustly mapped between vendors. Discrepancies often led to some confusion with the implementation of IHDs and other HAN devices. Full disclosure of issues between the vendors regarding technology and schedule risks provided increased confidence and more efficient issue resolution.
- System software and meter firmware upgrades must be highly-coordinated to ensure timely delivery and thorough completion of all upgrades.
- As illustrated by the number of upgrades performed over the course of the project, the team has come to realize the routine AMI system and meter firmware upgrades will be a way of life for enterprise deployments. This was not the case for the legacy AMR system.

2.2.1.2 Meter Data Management

Figure 2-23 illustrates the complex nature of the Siemens eMeter MDM implemented as part of the SmartMetering subproject.

Figure 2-23: EnergyIP MDM Application Components



2.2.1.2.1 Build

The KCP&L MDM system was deployed during Q1 2012 using the eMeter EnergyIP 7.2 software platform hosted by Siemens at their Customer Pilot Hosting Environment (CPHE) in Houston, TX. Initial interfaces were built between the MDM and KCP&L's internal CIS system and SmartGrid Middleware to deliver service point information and meter read data to the MDM. Additional interfaces were added following the initial launch to provide interactive two-way capabilities for Time-of-Use billing, remote service order processing, outage/restoration events and other meter events involving MDM, CIS, the AHE and Enterprise Service Bus (ESB). All meter read data (15 minute intervals and daily register reads) from the beginning of the AMI rollout in October 2010 is stored in the MDM system.

2.2.1.2.1.1 Phase 1 – Initial Launch

The MDM was implemented jointly by KCP&L and Siemens in three major phases, each made up of several subprojects. Phase 1 consisted of the initial launch of the system and key interfaces as well as the load of all historical meter read data from October 2010 through March 2012; this phase completed in March 2012. The MDM work necessary to support TOU billing was completed as part of this phase.

Preliminary scoping workshops were conducted in mid-2011 with development and configuration beginning in earnest in September. A key element was the stand-up of Siemens Customer Pilot Hosting Environment in Houston; this was the first time that eMeter or Siemens had implemented an eMeter installation in a Software-As-A-Service (SaaS) model. This included an internal Siemens-only Development environment as well as Test and Production environments that are connected to the corresponding KCP&L systems.

Basic configuration of the MDM included Validation, Estimation and Editing (VEE) settings, the various meter data services that process information within the MDM, all of the field values necessary to operate, configuration of the system calendar (bill cycles, holidays, etc.), user setup and security configuration. The TOU rates, calendar and usage framing setup work was also performed during this initial round of configuration activity.

KCP&L and Siemens implemented a number of core interfaces during this initial phase. They included the "FlexSync" interface to transmit incremental changes in service point information from CIS to MDM to keep the two systems in-sync with CIS acting as the system of record. KCP&L was the first customer to implement the "FlexSync" method instead of the traditional "batch" synchronization method that would send a full set of service point information for all customers on a regularly scheduled basis.

Meter reads are being sent to the MDM from the AHE via a secure file transfer process that transmits the register read file once daily with all 14,000 reads; the 15-minute interval reads are sent on an hourly basis to the MDM with approximately ¼ of the meters sending four hour blocks of intervals every hour which results in roughly 56,000 reads being sent every hour from AHE to MDM in the SmartGrid Demonstration Zone.

The final interface delivered during this phase was the "Pull Billing" interface that KCP&L is using to retrieve daily framed usage totals to be used in billing TOU customers. The "Pull Billing" interface uses the standard MDM interface in a non-traditional manner by pulling daily "Off-Cycle, Informational" reads instead of the standard monthly billing determinants; these daily totals are then fed through KCP&L's SmartGrid middleware where they are converted into virtual daily dial reads that can be used by the legacy CIS system for billing the TOU customers.

The final component of Phase 1 involved loading both service delivery point information and meter read data to the MDM system. Using the FlexSync process, KCP&L loaded approximately 14,000 records that included customer, account, service delivery point, premise and meter data to establish the appropriate and corresponding information within the MDM. All relationship records between these various data sets were loaded as of January 2012 and did not include any historical changes – i.e. move-ins/outs, meter exchanges, etc. that may have occurred from the beginning of the SGDP and AMI roll-out in October 2010. Once these service delivery points' records were fully loaded, KCP&L and Siemens then loaded the set of historical AMI data from October 2010 onward. By the time this load was completed in March 2012, approximately 5.8M historical daily register reads and 550M historical 15-minute interval reads had been loaded into the MDM. The ability to load this was aided by Landis+Gyr's willingness to retain the data longer than would typically be held during the gap between AMI roll-out and MDM stand-up and by Siemens flexibility in developing a load process; per the vendors, an MDM is typically implemented at the start of an AMI roll-out so that the data can begin loading from the onset.

2.2.1.2.1.2 Phase 2 – ESB Integration

The second phase of the MDM implementation took place over the middle and latter part of 2012. This phase focused on improving the security of the end-to-end system by moving the MDM and its interfaces to a VPN tunnel, as well as adding integration of the MDM with the ESB to allow KCP&L to take advantage of the various workflow, service order, and event management capabilities provided by the MDM. This phase completed in November 2012.

While preliminary workshops occurred in February 2012, work began in earnest in the April/May 2012 timeframe with a preliminary security assessment as well as a set of detailed Joint Design Sessions (JDS) that were hosted by KCP&L and included participation from the Siemens delivery team and eMeter/Siemens architects, as well as technical and project management support from Landis+Gyr and Intergraph.

Integration with the KCP&L SmartGrid ESB was one of the main development activities for both KCP&L and Siemens during Phase 2 of the MDM Implementation. The KCP&L ESB development provided interfaces between the MDM and CIS, OMS, AHE. Collectively, these interfaces support three different business processes. Siemens supported this integration work by implementing the eMeter L+G 5.1 Adapter (IEC61968-9 Version 1 compliant) which faces the AHE and supports receipt of outage, restoration and general meter event messages and the handling of remote connect/disconnect and on-demand read commands. Between CIS and MDM, to support the transmission of remote connect, remote disconnect, and on-demand read commands from CIS to the AHE, Siemens developed the "CIM2AG" adapter (IEC61968-9 Version 2 compliant) for transmitting messages between the EnergyIP Activity Gateway and KCP&L's ESB. Between OMS and MDM, Siemens developed the "OMS2CIM" adapter (IEC61968-9 Version 2 compliant) which currently supports transmission of Outage/Restoration events via the ESB to OMS. Configuration of the MDM was also performed by Siemens to support the necessary workflow for translation and management of the remote service orders as well as the outage and restoration events. General meter events (non-outage, non-restoration) are simply logged in the MDM for future analysis.

2.2.1.2.1.3 Phase 3 – Wrap-Up

The final phase of the MDM Implementation was completed in July 2013. Major elements completed in this phase can be broadly grouped into two categories: Functionality and Operational Support.

The category of "Functionality" includes both internal MDM configuration as well as some additional interface work between the MDM, ESB and other KCP&L SmartGrid Systems. The eMeter L+G Adapter was upgraded from the originally implemented 5.1 Adapter to the newer 5.7 Adapter; this enabled support for the Power Status Verification (PSV) interface between the OMS system and AMI infrastructure and also resolved outstanding defects in the original 5.1 adapter that KCP&L had identified. The PSV project enables the OMS system to send a PSV request message via the ESB to MDM where it is translated to the appropriate message type and then sent on to the AMI system for response. MDM provides workflow management for this process.

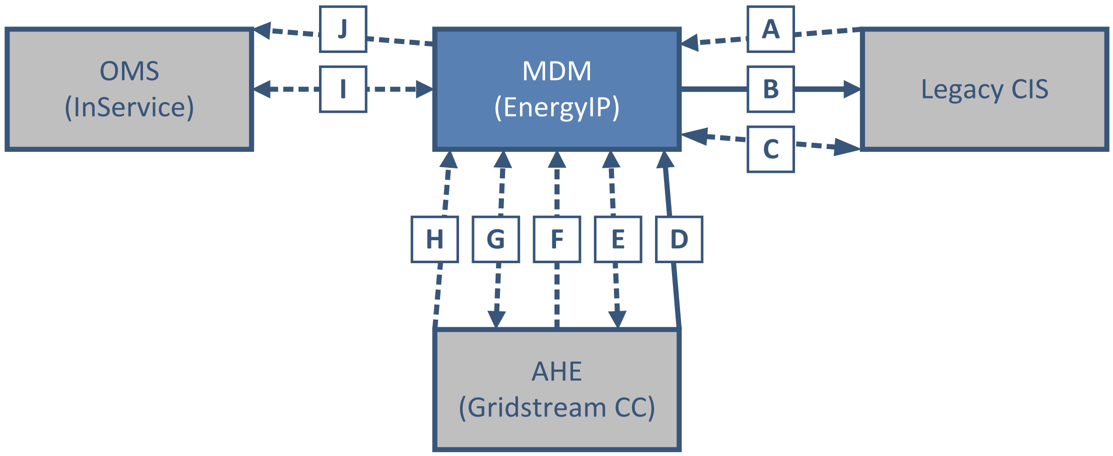
Interval data is at the core of two additional work packages – the aggregation of interval data for load research by KCP&L as well as the delivery of post-VEEed interval data from MDM to downstream systems such as the HEMP, DMAT and DERM. Configuration to deliver both of these outputs was performed in the MDM. While testing the delivery of post-VEEed data process, it was discovered that historical gap filling and the re-VEE of data caused data synchronization problems for many of the downstream systems and would cause adverse impacts to some of the existing downstream workflows, therefore KCP&L decided not to move forward with delivering this post-VEEed data to downstream systems.

A final set of functionality expanded the remote service order capability delivered in phase 2 to include remote disconnects and reconnects related to non-payment by customers; the majority of this work was performed in the CIS system to identify these customers whereas MDM re-used the existing workflow and support testing.

2.2.1.2.2 Integration

An overview of MDM system-to-system interfaces and applicable messages is illustrated in Figure 2-24.

Figure 2-24: KCP&L SmartGrid Demonstration Project MDM Integration



The integration touch points for the MDM are as follows:

A. Customer Information data initiated from CIS to MDM. Also known as "FlexSync", this incremental data is used to keep CIS and AHE in-sync for customer records, service connectivity, and meter deployment/exchange purposes.
B. Billing Determinant data initiated from MDM to CIS. This data is requested daily by CIS and is used to update CIS with proper billing determinant information for TOU customers including summer On-Peak, summer Off-Peak, and winter Off-Peak consumption data.
C. Remote Service Order request-reply messages initiated from CIS to MDM. This consists of a single IEC 61968 CIM-formatted service order request from CIS to MDM and a single IEC 61968 CIM-formatted service order reply from MDM to CIS once the service order has been executed between MDM and AHE. See Item E. below.
D. Daily Register and Interval Read data initiated from AHE to MDM. This is California Metering Exchange Protocol (CMEP)-formatted data sent hourly to be store in the meter usage data repository and used for TOU billing determinants.
E. Remote Service Order request-reply messages, including On-Demand Read and Remote Service Connect/Disconnect, initiated from CIS to MDM and sent from MDM to AHE. These are IEC 61968 CIM-formatted request-reply messages used to get on-demand reads and execute remote service connect/disconnects on eligible target SmartMeters. See Item C. above.
F. General Event notification initiated from AHE to MDM. This is an IEC 61968 CIM-formatted event message used to notify MDM of various MDM-supported events (using the corresponding CIP 4-part IDs) that occur within the AMI system. MDM can then log these events and/or route them to other subscribing systems.
G. Power Status Verification request-reply initiated from MDM to AHE in the form of an On-Demand Read request-reply. This is an IEC 61968 CIM-formatted request-reply used to verify power status (On, Unknown, or Service Disconnected) at a target SmartMeter. See Item I. below.
H. Outage/Restoration Event notification initiated from SmartMeters to MDM. This is an IEC 61968 CIM-formatted event message used to notify MDM of an outage or restoration event occurring at a SmartMeter.

I. Power Status Verification request-reply initiated from OMS to MDM. This is an ESB-translated request-reply used to verify power status (On, Unknown, or Service Disconnected) at a target SmartMeter. See Item G. above.

J. Outage/Restoration Event notification initiated from MDM to OMS. This is used to notify OMS of an outage or restoration event occurring at a SmartMeter.

2.2.1.2.3 Post-Implementation Operational Issues

Following the standup, integration, and preliminary testing of the MDM system, numerous post-implementation operational issues needed to be mitigated and considered. These issues included the following:

- VPN connection has periods of instability; there is not a redundant connection, so when the tunnel is down, the MDM system is inaccessible. For future off-site hosting, redundant connection should be implemented similar to what was done with the L+G MPLS connection.
- Siemens has experienced several power outage and connectivity issues with their hosting solution. While the solution was only built to support this as a “demonstration”, it underscores the need for a robust hosting solution including redundant power supplies and redundant lines of communication.
- The MDM system appears to have a “race” condition within its order processing when handling Remote Service Orders. The MDM receives an “asynchronous” response for On-Demand Reads from the AHE and has to do two things with this data. (1) MDM writes the read value to an internal table; (2) MDM updates the status of the open order which triggers the response message to KCP&L’s CIS+ system. There does not appear to be anything internal within the MDM that forces #1 to happen prior to #2, so the CIS regularly receives a response that does not have a meter read value included. Upon investigation, the read value can be seen in MDM, hence the belief by KCP&L that a “race” condition is occurring. Siemens has been unable to identify or resolve this issue.
- Daylight savings time (both “spring forward” and “fall back”) has caused issues with system processing on both the KCP&L side as well as the MDM side.
  - The MDM product required a bug fix to resolve an issue on the “fall back” date where it wouldn’t allow the load of a file with 100 intervals instead of the regular 96. This was resolved in 1Q 2013 and ran successfully in November 2013.
  - The MDM product doesn’t handle the “standard” CMEP format file on the “spring forward” date which sends a file with only 92 intervals. Since MDM is expecting 96 intervals, it estimates the missing 4 intervals. L+G has an “enhanced” CMEP format, however the Siemens MDM does not accept that format with its current adapter. This was handled manually by KCP&L team members for 2013 and the same approach will be used to handle this in 2014.
  - KCP&L interface sends a date/time stamp on pull billing requests for TOU; KCP&L development resources were unable to successfully deploy a working fix to modify the “UTC” value sent over on the days when the daylight savings time change occurs, so the requests had to be manually resubmitted. The manual workaround will be used to support the remaining DST changes.
- KCP&L primarily used contract resources to implement the interfaces to MDM. Once these resources rolled off, the internal team members were left to support solutions that were not within their primary area of expertise and which were not the KCP&L target state solution. This has made it more difficult to troubleshoot issues.

2.2.1.2.4 Lessons Learned

Throughout the build, integration, and daily operation of the MDM system, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- Industry standards were not readily available from vendors to support interoperability; in every case (MDM, OMS, and AHE), KCP&L was required to have either KCP&L, project vendors, or both perform custom development work to support these standards, despite the claim that the vendor systems were supposed to be standards compliant.
- For future off-site hosting, a redundant connection should be implemented similar to what was done with the L+G MPLS connection.
- Future hosted solutions should be installed and maintained at a traditional industry standard data center which provides a robust hosting solution including redundant power supplies and redundant lines of communication.
- Per feedback from Siemens as part of this project, as well as other MDM vendors, an MDM solution is more commonly deployed prior to or at the beginning of an AMI rollout which eliminates the need for a historical data load.
- The legacy CIS+ system was unable to accept billing determinants from the MDM. KCP&L had to build a custom process to load MDM generated billing determinants into the CIS+ system to support TOU billing. This MDM-CIS integration point is a key benefit that will be delivered by the new target state systems.
- For future systems that will be implemented by 3rd party system integrators or contract resources, it is imperative that an effective knowledge transfer and system training plan be put into place to ensure that the KCP&L team members will be able to fully support the system once the external resources have rolled off the project.
- Future MDM systems need enhanced workflow management internal to their systems to prevent issues such as the RSO “race” condition from occurring.
- Due to this being a “demo” project, KCP&L business users have not been actively using the MDM system and have only used their existing legacy CIS+ systems to view meter read data. This has left the IT team as the only active user of the system for troubleshooting and support of order processing. For future installations, it will be imperative to get business teams such as Billing Services, Customer Care and Meter Technology engaged in actively using and supporting MDM activities.
- Efforts to export data from the MDM for downstream systems met with mixed success due to difficulty in identifying and mapping the necessary data from the MDM for each target system. Delivery required customization by either Siemens or KCP&L to deliver and in several cases was abandoned due to preference for target systems (i.e. DMAT) to receive “raw” data directly from the AHE instead of VEE’d data from MDM.
- eMeter MDM implementation did not include the “Analytics” package that came with a later release. Lack of an analytics friendly data schema limited effectiveness of user interaction within the MDM system and drove end users to rely on DMAT or other systems for analytics. For future KCP&L projects, implementation of the appropriate MDM Analytics schema will be an important long term success factor for the implementation.

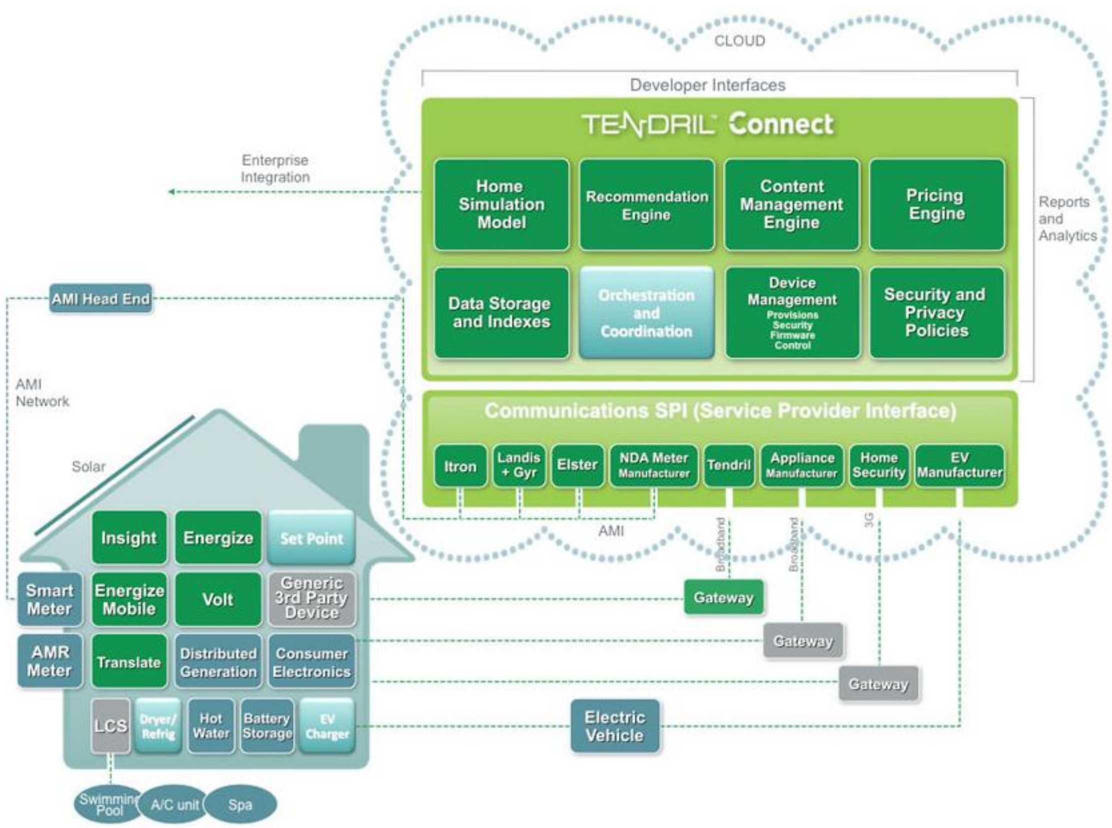
2.2.2 SmartEnd-Use

The SmartEnd-Use subproject deployed a state-of-the art Home Energy Management Portal with optional In-Home Displays, Stand-alone PCTs, complete HAN implementations, and TOU pricing programs. The following subsections summarize these Smart-End Use component deployments.

2.2.2.1 Home Energy Management Web Portal

The Customer Home Energy Management Web Portal program was rolled-out to KCP&L customers in October 2010, coinciding with the AMI implementation and IHD deployments. KCP&L chose to implement Tendril's Connect platform to provide customers with both a web-based portal and in-home devices.

Figure 2-25: Tendril™ Connect Platform Architecture



2.2.2.1.1 Build

KCP&L chose to implement the HEMP system as a managed-service and hosted-platform, with Tendril in charge of hosting the backend servers and systems and capturing meter reads to meet contractual performance criteria.

For the development environment, Tendril stood-up a hosted back office platform cloned from the production system. The hosted development environment interfaced with the development DERM and AHE. Over 25 meters in the AMI lab were associated to development HEMP accounts to emulate real-life customer meters. These development environments and interfaces were used to test all HEMP requirements, including system-to-system integration and HAN device testing.

Integration with the customer AccountLink was completed to enable Single Sign-On (SSO) access to the portal for customers. Secure account sign-on is managed by an interface between HEMP and AccountLink that utilizes Security Assertion Markup Language (SAML).

2.2.2.1.1.1 Energy Usage Information

Historical AMR usage meter reads were loaded into the HEMP up-front to give customers immediate access to up to two years of historical usage information. Integration was completed with the AHE to populate the portal with accurate customer usage. Day-behind meter reads are passed from the AHE through Message Queue (MQ) Broker interfaces to the HEMP on a daily basis. The data is then offset by a fixed value equal to the customer's last AMR read to provide a seamless transition between AMR data and AMI data. Customers with a HAN configuration receive real-time meter reads in their portal from the HAN Gateway pulling real-time meter reads from the SmartMeter and sending them to the portal via the Internet.

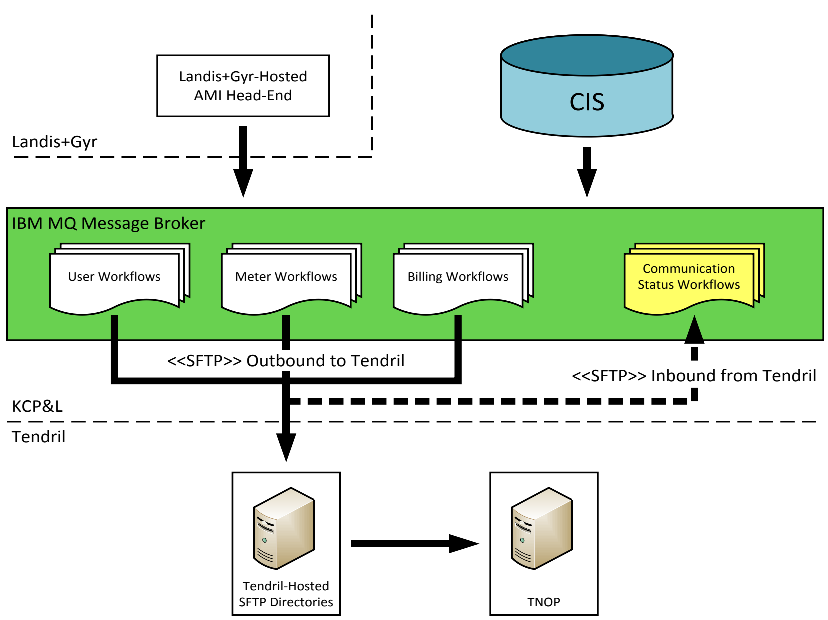
2.2.2.1.1.2 Billing Information (Estimated Billing True-Ups)

Integration was completed with the CIS to populate the portal with accurate customer historical and estimated billing information. A special process was created to estimate the customer billing information with accurate taxes and fees based on the customer's current rate. The bill estimate provides and end-of-bill-cycle projected bill based on usage-to-date in a given billing cycle. Historical billing information and daily estimated bill "true-ups" (including taxes and fees) are created by the CIS and passed through an MQ Broker interface to HEMP to be displayed in the portal. Upon receipt of successful estimated bill "true-up" messages to HEMP, CIS pulls the "true-up" back from Tendril to be sent to customer IHDs on a daily basis by use of a "tunnel text message". The tunnel text message provides a means of getting custom data into the IHD via the built-in ZigBee text messaging mechanism by use of special characters within the message for the device to interpret appropriately.

2.2.2.1.1.3 Pricing Signals

Integration was completed with the CIS to populate the portal with accurate customer pricing information. Pricing signals based on customers rates are created by the CIS and passed through an MQ Broker interface to HEMP to be displayed in the portal. Upon receipt of successful pricing signals, CIS pulls the pricing message back from Tendril to be sent to IHD via the AHE and SmartMeter using the ZigBee SEP 1.0 "publish price" command. A special event pricing signal was required to support TOU rates. Sent on a daily basis, TOU event pricing signals are sent to trigger a peak-price change from 3 – 7 PM.

Figure 2-26: Customer Web Portal Data Flows



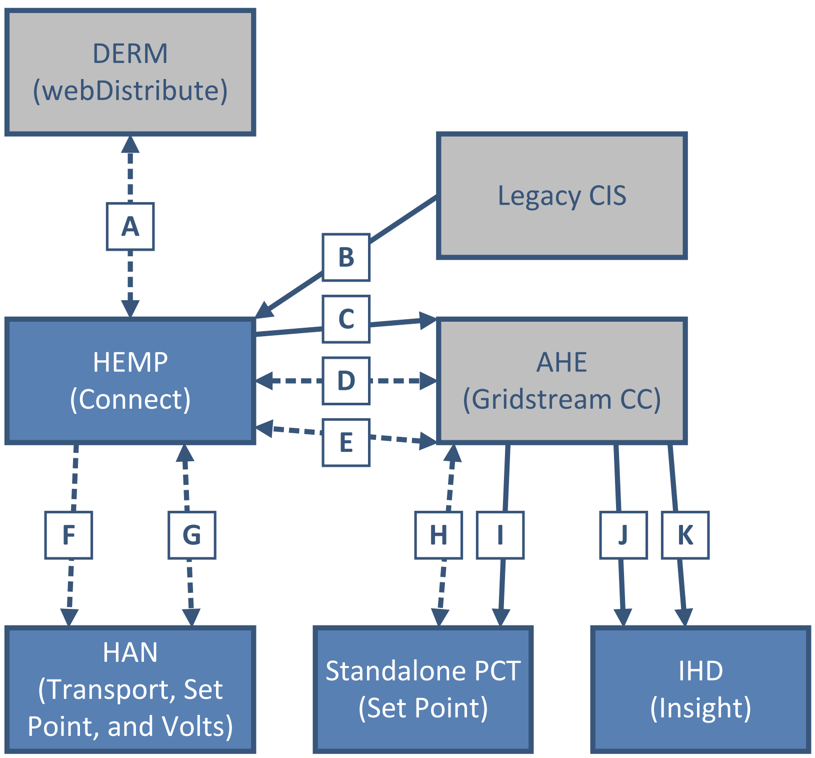
2.2.2.1.1.4 Demand Response Events

Integration was completed with the DERM to receive OpenADR-based demand response events. Demand response events are received into an OpenADR adapter at HEMP, where they are routed base on the target asset(s) (HAN vs. Stand-alone PCT). For messages directed to HANs, HEMP sends the demand response events directly to the HAN gateway via the Internet and receives event participation messages from the HAN via the same interface. For messages directed to Stand-alone PCTs, integration was completed with the AHE to allow demand response events and event participation messages to be sent between the two systems. The AHE manages the interface and messaging between the AHE and the Stand-alone PCTs.

2.2.2.1.2 Integration

An overview of HEMP system-to-system interfaces and applicable messages is illustrated in Figure 2-27.

Figure 2-27: KCP&L SmartGrid Demonstration Project HEMP Integration



The integration touch points for the HEMP are as follows:

A. Demand Response Event request initiated from DERM to HEMP, and Event Opt-Out/Opt-In reply initiated from HEMP (for both HANs and Stand-alone PCTs) to DERM. These are OpenADR-formatted request-reply messages used to notify HEMP of creation, modification, or cancellation of impending DR events and to notify DERM of DR assets' event participation status.

B. Consumption Pricing and Billing True-Up messages initiated from CIS to HEMP. These messages are sent daily to update the customer portal and IHDs with real-time per-kWh consumption pricing information and up-to-date estimated billing information.

C. Consumption Pricing and Billing True-Up messages initiated from HEMP to AHE. These “tunnel text messages” are sent daily to update customer IHDs with real-time per-kWh consumption pricing information and up-to-date estimated billing information.

D. Get Device Info request-reply initiated from HEMP to AHE. This is an IEC 61968 CIM-formatted request-reply used to gather HAN device information for AMI-based DR assets (Stand-alone PCTs).
E. Demand Response Event request initiated from HEMP to AHE, and Event Opt-Out/Opt-In reply initiated from AMI-based DR assets (Stand-alone PCTs for this project) to HEMP. These are IEC 61968 CIM-formatted request-reply messages used to notify AMI-based DR assets of creation, modification, or cancellation of impending DR events and to notify HEMP of AMI-based DR assets' event participation status.
F. Device Control signals initiated from HEMP to HAN devices via the Internet. These are ZigBee SEP 1.0-formatted request messages triggered by customer actions in the portal and used to control HAN devices including changing PCT temperature set point and turning LCS devices on/off.
G. Demand Response Event requests initiated from HEMP to HAN DR assets via the Internet, and Event Opt-Out/Opt-In replies initiated from HAN DR assets to HEMP via the Internet. These are ZigBee SEP 1.0-formatted request-reply messages used to notify HAN DR assets of creation, modification, or cancellation of impending DR events and to notify HEMP of HAN DR asset event participation status.
H. Demand Response Event requests initiated from AHE to AMI-based DR assets (Stand-alone PCTs for this project) via SmartMeters, and Event Opt-Out/Opt-In replies initiated from AMI-based DR assets to AHE via SmartMeters. These are ZigBee SEP 1.0-formatted request-reply messages used to notify AMI-based DR assets of creation, modification, or cancellation of impending DR events and to notify AHE of AMI-based DR asset event participation status.
I. Consumption Pricing messages initiated from AHE to Stand-alone PCTs. These "tunnel text messages" are ZigBee SEP 1.0-formatted messages sent daily to update customer Stand-alone PCTs with real-time per-kWh consumption pricing information.
J. Estimated Bill True-Up messages initiated from AHE to IHDs. These "tunnel text messages" are ZigBee SEP 1.0-formatted messages sent daily to update customer IHDs with up-to-date estimated billing information.
K. Consumption Pricing messages initiated from AHE to IHDs. These "tunnel text messages" are ZigBee SEP 1.0-formatted messages sent daily to update customer IHDs with real-time per-kWh consumption pricing information.

2.2.2.1.3 Post-Implementation Operational Issues

Following the standup, integration, and preliminary testing of the HEMP, numerous post-implementation operational issues needed to be mitigated and considered. These issues included the following:

- As part of the initial stand-up, KCP&L decided to add the last pre-exchange AMR meter read to the new AMI meter reads (all of which started at 0 kWh). This was done to give customers immediate access to their historical usage data with a seamless transition between AMR data and AMI data that started at "0" kWh. However, this eventually caused issues for customers who had meter exchanges performed (due to meter issues) because additional offsets were not tracked and added for AMI meters that were exchanged. This discontinuity in the meter data led to meter data "spikes" due to the change in the order of data magnitude. See next item.
- Tendril's platform was designed to utilize register reads, as opposed to interval reads. This caused issues in the case of meter exchanges because the new meter reads would be on a different order of magnitude from the previous meter (for example, the previous meter

register reads could be “30,000 kWh”, while the new meter register read would be “0 kWh”). These abrupt order of magnitude changes in meter read data would cause data “spikes” in the customer presentation in the portal. This resulted in inaccurate representations of usage and cost at the time of the meter exchange. This issue would not present itself in an environment that utilized interval reads as the interval reads would remain at a relatively steady magnitude regardless of the register read magnitude.

- Tendril’s platform did not initially support block rate pricing. The short-term fix for this involved manually send price updates to Tendril’s platform – this was fixed by manually sending pricing information to the Tendril platform to pick up any rate changes that may have gone into effect on the previous day (i.e. customer moved into the next usage block of the rate on the previous day). This issue was resolved in the long-term when Tendril included support for block rates in the first platform upgrade.
- Customer portal accounts in the HEMP platform were each given a unique ID made up of a concatenation of customer Account ID and Service Point ID. This meant that each customer account was associated to a specific customer at a specific location, instead of being associated to a specific customer. This means that new accounts had to be created every time a customer moved to a new residence, thus resulting in the loss of historical usage data from the customer’s new account.
- KCP&L undertook two major HEMP platform upgrades during the project to support required project functionality and maintain technical support from Tendril. These upgrades required extensive testing of bugs and fixes. The time required for testing was initially underestimated and required additional resources than expected.
- Numerous issues arose with the device installation process of the IHD program. One issue was the device IDs not being communicated properly to the AHE during the device provisioning process. Another issue was that KCP&L was unable to verify whether or not the IHDs were plugged-in by the customer after delivery during the “white glove” process. Most of these issues were mitigated during the Stand-alone PCT and HAN installations due to the fact that these devices required in-home installation and verification by a trained workforce. Installers were able to correctly verify device IDs and successfully complete device provisioning to the Smart Meter while in the customer’s home.
- Meter exchanges caused issues with HAN device association in that the device(s) would stay associated with the old meter that was exchanged. In order to get the same device provisioned to the new meter, the device(s) needed to be manually cleaned from the AMI database whenever meters were exchanged. This reallocated the device(s) within the AHE database to be provisioned to the new meter.

2.2.2.1.4 Lessons Learned

Throughout the build, integration, and daily operation of the HEMP system, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- Interval data is much more desirable than register reads due to the issues that register reads can cause. With interval reads, data presentation has no dependence on the relationship between reads over time. However, processing register reads can cause issues in the event of meter exchanges, as significant changes in the order of magnitude between two consecutive reads can cause abnormalities in data presentation.
- Loading two years of historical AMR data and creating a process to offset customers new AMI data by a fixed value equal to their last AMR read had benefits up-front in that it allowed customers access to their historical consumption data with a seamless transition between AMR data and AMI data. However, this caused data presentation issues any time

a customer had a meter exchange in that the offset only account for the last AMR read and did not account for the last AMI read of any interim AMI meters.

- Due to the fact that customer HEMP IDs were associated to a specific customer at a specific premise, historical customer usage data did not carry over when customers would move to new locations in the Project Area. High customer turnover in the Project Area led to an exorbitant number of unused accounts that were not deleted after the customers moved out.
- ZigBee SEP 2.0 was not completed during the product development and deployment cycles, so all functionality was limited to functionality available in SEP 1.x. Certain functionalities that exist in Legacy KCP&L thermostat programs (i.e. Energy Optimizer) are not supported by SEP 1.x, such as HVAC cycling, so these functionalities were not available or implemented as a part of this project.
- The OpenADR 2.0 Profile A standard was implemented for the DR interface between HEMP and DERM. This was the first OpenADR integration that Tendril had been involved with, thus Tendril had to develop a special OpenADR appliance to handle OpenADR-formatted DR messaging between HEMP and DERM.
- A special bill-estimation tool needed to be created to generate accurate billing true-ups that included taxes and fees. This was required due to varying customer fees across different customer rates. This tool helped deliver accurate estimated billing information to customers on a daily-basis. This estimated-billing information includes price-to-date as well as projected end-of-month costs based on usage-to-date in the current billing cycle.
- Tendril's platform does not currently support net metering and negative usage data (-kWh) was not displayed properly in the portal. Thus, customers with net metering did not have the same experience as non-net metered customers.
- A sufficient lab environment was not created early on in the project to give KCP&L and Tendril an accurate representation of the KCP&L implementation. This made it difficult to replicate the customer environment for troubleshooting issues. This was resolved in the middle of the project when robust lab was built-out including a HEMP system cloned from Production, an AMI infrastructure, and numerous HAN devices spanning all three HAN device programs.

2.2.2.2 In-Home Display

The IHD was rolled out to KCP&L customers in October 2010, coinciding with the AMI and Customer Web Portal deployments. Integration was completed with the AHE, CIS, and SmartMeters to populate the IHDs with accurate real-time usage information, real-time energy cost information, and estimated billing information.

2.2.2.2.1 Build

The IHD core capabilities are part of Tendril's a commercially available, productized software solution which can be configured to the needs of a given utility. By pursuing this "off-the-shelf" philosophy to the maximum degree possible, limited design and development was required. The following sections provide a summary of the development and configurations that were required to implement and deploy the desired IHD functionality.

2.2.2.2.1.1 AMI Backhaul and HAN Management

The IHD is provisioned to the SmartMeter-managed HAN. The HAN is a ZigBee network supporting SEP 1.x. The IHD receives real-time usage information directly from the SmartMeter. Daily estimated bill "true-up" messages and pricing information are sent to the IHD via the AMI network and through the

SmartMeter. Device management (provisioning, de-provisioning, etc.) is performed within the AHE by customer service representatives within KCP&L.

2.2.2.2.1.2 Energy Usage Information

The IHD receives real-time demand (kW) and consumption (kWh) data directly from the SmartMeter. The IHD processes this information, along with pricing signals from the SmartMeter, to give customers and accurate real-time estimate of cost and consumption for the present day as well the previous day.

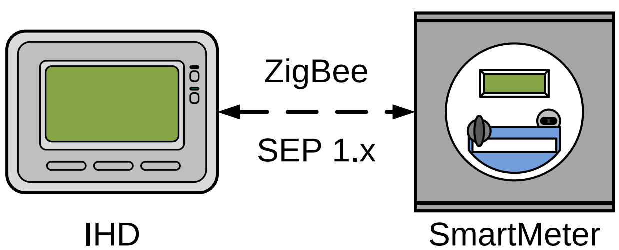
2.2.2.2.1.3 Billing Information (true-up)

A special process was created to estimate the customer billing information with accurate taxes and fees based on the customer's current rate. The bill estimate provides and end-of-bill-cycle projected bill based on usage-to-date in a given billing cycle. Estimated bill "true-up" messages are sent to customer IHDs on a daily basis by use of a "tunnel text message". The tunnel text message provides a means of getting custom data into the IHD via the built-in ZigBee text messaging mechanism by use of special characters within the message for the device to interpret appropriately.

2.2.2.2.1.4 Pricing Signals

Pricing signals based on customers rates are created by the CIS and passed through an MQ Broker interface to the AHE. Pricing signals are sent to the IHD via the AMI network through the SmartMeter using the ZigBee SEP 1.0 "publish price" command. Customers can then see their real-time energy price and accumulated daily costs. A special event pricing signal was required to support TOU rates. Sent on a daily basis, TOU event pricing signals are sent to trigger a peak-price change from 3 – 7 PM.

Figure 2-28: In-Home Display Communication



2.2.2.2.2 Post-Implementation Operational Issues

Following the initial integration, testing and deployment of the IHDs, numerous post-implementation operational issues needed to be considered and mitigated. These issues included the following:

- During the IHD program deployment, an issue was found in the IHD firmware that modified the IHD screen contrast rendering the screen unreadable. This issue was resolved by returning the current inventory of IHDs to Tendril and receiving a new shipment of IHDs on a newer firmware version containing a fix for this bug. As for the IHDs that were already deployed, these were replaced one-by-one as the affected customers contacted KCP&L to report the issue.
- While not an IHD issue directly, a bug with the ZigBee chip in the meter caused a modification to the price pushing process for the IHD where the ZigBee chip had to be reset for pricing changes to take effect on the IHD. This was temporarily remedied with a workaround that involved sending multiple commands to the meter to reset the chip and send the price. Long term, this was remedied with a firmware upgrade to the meter.
- Furthermore, since the Tendril platform did not initially support block rates, including the KCP&L standard residential declining-block rate, pricing changes were not automatically

triggered to the IHDs when the customer moved into a new usage block within the rate. The short-term fix for this issue involved sending the correct price to the IHD on a daily basis, in order to pick up any rate changes that may have gone into effect on the previous day (i.e. customer moved into the next usage block of the rate on the previous day). This issue was resolved in the long-term when Tendril included support for block rates in the first platform upgrade.

- Prior to the first HEMP platform upgrade, Tendril frequently encountered issues when processing estimated bill "true-up" messages. Consequently, CIS was never notified of a successful "true-up" receipt at HEMP and was unable to pull the "true-up" message back from HEMP. This broke the defined "true-up" process and resulted in "true-up" messages not getting sent to customer IHDs.

2.2.2.2.3 Lessons Learned

Throughout the deployment and daily operation of the IHDs, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- A special "tunnel text message" was implemented to support getting estimated billing information into the IHD. This message contained unique identifiers to enable it to "tunnel" into the IHD and was required to update the billing information within the IHD.
- Tendril's IHD does not currently support net metering. Negative usage data (-kWh) was not displayed properly on the IHDs. Thus, customers with net metering did not have the same experience as non-net metered customers.
- The IHD offering in conjunction with meter installation resulted in goodwill but created some technical and user challenges. For example, device installation codes need to be correlated with the proper meter IDs to ensure communications between the IHD and the meter. This requires strict attention to detail when recording codes and meter IDs. Also, the meter-to-device associations need to be made in a timely manner and could have benefited from a more hands-on provisioning process instead of relying on the customer to contact KCP&L support to finish the device pair process. Despite the convenience of having a device delivered to them through the "door knock" initiative, many customers did not utilize their IHDs. KCP&L saw better customer engagement on the Stand-alone PCT and HAN programs, as these programs involved devices that customers already use on a daily basis (thermostats, water heaters, etc.). Furthermore, device reliability and persistent connectivity issues negatively affected on-going customer participation. After deploying over 1,200 IHDs, approximately 600 IHDs remained operational at the end of the project.

2.2.2.3 Stand-alone Programmable Communicating Thermostat

The Stand-alone PCT program was rolled-out to KCP&L customers in June 2012. Along with the built-in programmable schedule, the Stand-alone PCT supports pricing signals and demand response events via communications with the SmartMeter. Integration was completed with the AHE, CIS, and SmartMeters to populate the Stand-alone PCTs with real-time pricing information to enable customers to make energy and cost conserving decisions when programming the temperature set point and programmable schedule.

2.2.2.3.1 Build

The PCT core capabilities are part of Tendril's a commercially available, productized software solution which can be configured to the needs of a given utility. By pursuing this "off-the-shelf" philosophy to the maximum degree possible, limited design and development was required. The following sections provide a summary of the development and configurations that were required to implement and deploy the desired PCT functionality.

2.2.2.3.1.1 AMI Backhaul and HAN Management

The Stand-alone PCT is provisioned to the SmartMeter-managed HAN. The HAN is a ZigBee network supporting SEP 1.x. DR event messages and pricing information are sent to the Stand-alone PCT via the AMI network and through the SmartMeter. Prior to provisioning the Stand-alone PCT to a customer's SmartMeter, the customer's Customer Web Portal account is configured to support the PCT. Device management (provisioning, de-provisioning, etc.) is performed within the AHE by customer service representatives within KCP&L.

2.2.2.3.1.2 Programmable Schedule

The Stand-alone PCT contains a built-in programmable schedule that allows the customer to choose when and how to change their thermostat set point at multiple times throughout the day. The customer can select the set point and time to change it for four different time slots on each day of the week. The customer can also select the mode for the thermostat to operate under, with the options of Schedule (follows the customer-programmed schedule), Hold (holds the set point at a fixed value), and Vacation (adjusts the set point for a selected window of time).

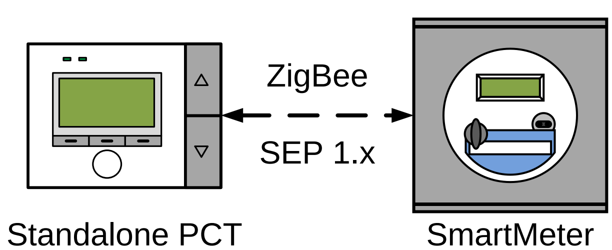
2.2.2.3.1.3 Pricing Signals

Pricing signals based on customers rates are created by the CIS and passed through an MQ Broker interface to the AHE. Pricing signals are sent to the Stand-alone PCT via the AMI network through the SmartMeter using the ZigBee SEP 1.0 "publish price" command. Customers can then see their real-time energy price. A special event pricing signal was required to support TOU rates. Sent on a daily basis, TOU event pricing signals are sent to trigger a peak-price change from 3 – 7 PM.

2.2.2.3.1.4 Demand Response Events

The Stand-alone PCT also supports demand response functionality. Through integration between the DERM, HEMP, and AHE, the Stand-alone PCTs can receive demand response events to help reduce, level, or shift load during peak demand periods. The DERM can forecast demand on the distribution grid and call on the Stand-alone PCTs for load reduction, if necessary. A message is sent from the DERM to the HEMP to identify the Stand-alone PCT customers needed to meet the load reduction requirements. The HEMP then routes the demand response messages to the AHE. The AHE passes the demand response events to the Stand-alone PCTs via the SmartMeters prior to or at the start time of the event, depending on the event parameters. Once received at the Stand-alone PCT, the customer is automatically opted into event participation with the option to opt out of the event at any time prior to the end of the event. This opt-out/in decision can be made directly at the device. Customer event participation information is then passed to the DERM via the AHE and HEMP to be used for post-event analysis and future demand response forecasting.

Figure 2-29: Stand-alone PCT Communication



2.2.2.3.2 Post-Implementation Operational Issues

Following the initial integration, testing and deployment of the Stand-alone PCTs, numerous post-implementation operational issues needed to be considered and mitigated. These issues included the following:

- The initial shipment of Stand-alone PCTs had to be returned to Tendril because they did not meet project requirements, with the primary issue being that they were not SEP 1.1-certified. These devices were returned to Tendril and replaced with Tendril's newer model PCT that met project requirements for Standards and DR integration.
- Standards-based DR integration between Tendril and L+G did not exist out of the box. Tendril and L+G worked together to develop CIM-based DR integration between the HEMP and the AHE. This additional work led to delays in the deployment schedule of the Stand-alone PCT. Due to the SEP 1.x compliance of both the SmartMeter and the Stand-alone PCT, no integration development was required between the two devices.
- A "get HAN device information" request was required from the HEMP to the AHE to register the Stand-alone PCT to a customer's account. This messaging integration was not ready when the Stand-alone PCTs were rolled out to customers, so KCP&L had to go back and register each device in the HEMP once the integration was completed.
- The HEMP included the customer's Tendril networkId for each Stand-alone PCT in the DR event request messages to the AHE, but the AHE required the Meter ID to be included in the DR event request message. Thus, the ESB utilized a call to the CIS to perform the translation from Tendril's networkId to the KCP&L Meter ID.
- Even though the translation from Tendril's networkId to the KCP&L Meter ID was performed in the ESB, the HEMP required the meter ID information associated with each Stand-alone PCT. A valid meter ID was required to be associated to the networkId for the Stand-alone PCT to perform Stand-alone PCT account registration and to participate in DR events, which caused an additional point of maintenance within the HEMP.
- When a meter swap occurred on a meter that had a Stand-alone PCT registered to it, the Stand-alone PCT had to be re-provisioned to the new meter and the Meter ID had to be updated in the HEMP platform.

2.2.2.3.3 Lessons Learned

Throughout the deployment and daily operation of the Stand-alone PCTs, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- The number of compatible HVAC systems was lower than expected among customers in the project demonstration zone, thus customer enrollment and participation in the Stand-alone PCT program turned out to be lower than initially anticipated. Many homes either had non-central heating/cooling (e.g. window air-conditioner) or had systems that were not compatible with Tendril's thermostat. In some instances, KCP&L utilized an "add-a-wire" kit to enable compatibility between the Tendril thermostat and the customer's 4-wire HVAC system. Often times, a customer would be interested in signing up for the Stand-alone PCT program, but would be disqualified during the pre-installation screening or at the in-home visit due to these incompatibilities.
- Meter ID information should not be stored in the HEMP, because this creates an extra point of maintenance when meter swaps occur.
- If any translations are required between system asset identifiers (account number, service point ID, meter ID, etc.), the ESB should handle these translations.

2.2.2.4 Home Area Network

The HAN program was rolled-out to KCP&L customers in February 2012. The HAN was initially available to a small set of “friends and family” to verify functionality. Once these “friends and family” HANs were installed and verified, customers within the SGDP were then able to enroll in the HAN program based on a set of prequalification criteria (broadband internet connectivity, HVAC type, presence of a 240V load, etc.). Integration was completed with the CIS to send pricing information to the HAN via the HEMP to populate the HAN PCT devices with real-time pricing information to enable customers to make energy and cost conserving decisions when programming the temperature set point and programmable schedule.

2.2.2.4.1 Build

The HAN core capabilities are part of Tendril’s a commercially available, productized software solution which can be configured to the needs of a given utility. By pursuing this “off-the-shelf” philosophy to the maximum degree possible, limited design and development was required. The following sections provide a summary of the development and configurations that were required to implement and deploy the desired HAN functionality.

2.2.2.4.1.1 Broadband Backhaul and HAN Management

The HAN consists of a broadband-connected HAN gateway that interfaces directly with the HEMP servers, one or two PCTs depending on the customer’s HVAC configuration and compatibility, two 120V LCSs and an optional 240V LCS if the customer has a compatible load (e.g. pool pump, electric water heater, etc.).

The HAN is provisioned to the SmartMeter-managed HAN. The HAN is a ZigBee network supporting SEP 1.x. DR event messages and pricing information are sent to the HAN via a broadband-connection from Tendril servers to the HAN gateway. Prior to provisioning the devices to the customer’s SmartMeter, the customer’s Customer Web Portal account is configured to support the HAN devices. Device management (provisioning, de-provisioning, etc.) is performed within the AHE by customer service representatives within KCP&L. Once the devices are provisioned to the SmartMeter, they are registered within the Customer Web Portal using the device MAC Address. Once registered within the Customer Web Portal, the customer can then access and control the devices, including changing temperature set point, PCT schedule, and pricing rules for the PCT and LCSs within the HAN.

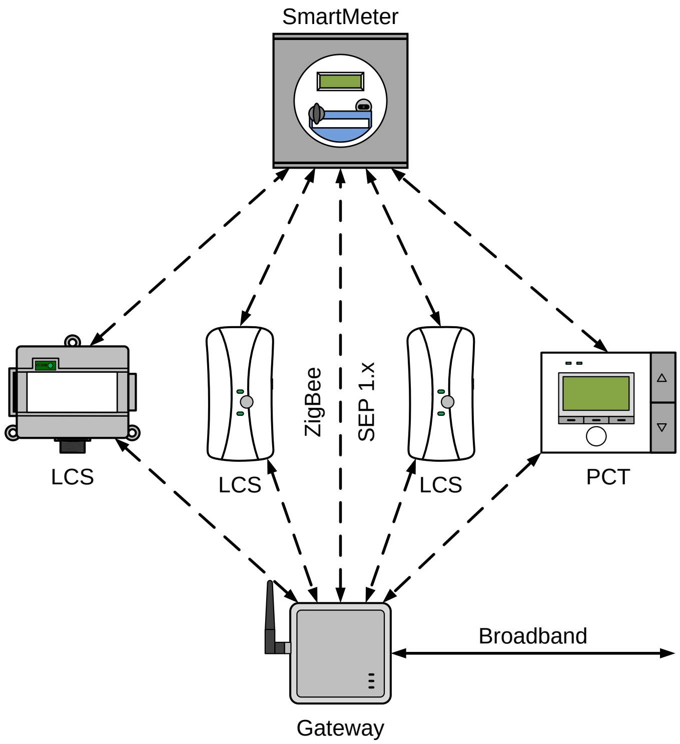
2.2.2.4.1.2 Programmable Schedule

The PCT contains a built-in programmable schedule that allows the customer to choose when and how to change their thermostat set point at multiple times throughout the day. The customer can select the set point and time to change it for four different time slots on each day of the week. The customer can also select the mode for the thermostat to operate under, with the options of Schedule (follows the customer-programmed schedule), Hold (holds the set point at a fixed value), and Vacation (adjusts the set point for a selected window of time).

2.2.2.4.1.3 Pricing Signals

CIS was configured to send pricing signals to the HEMP based on the customers’ rate codes. These pricing signals are pulled from the HEMP by the HAN gateway rather than through the metering network and are displayed on the PCT. Customers are able to see real-time pricing information on the screen of the PCT to make energy conserving decisions when programming the temperature set point and schedule. TOU pricing signals are managed within the HEMP based on rate information sent from CIS. TOU peak/Off-Peak pricing signals are sent to HAN devices via the HAN gateway at 3 PM (peak) and 7 PM (Off-Peak).

Figure 2-30: Home Area Network Communication



2.2.2.4.1.4 Demand Response Events

The HAN also supports demand response functionality. Through integration between the DERM and the HEMP, the HAN can receive demand response events to help reduce, level, or shift load during peak demand periods. The DERM can forecast demand on the distribution grid and call on the HANs for load reduction, if necessary. A message is sent from the DERM to the HEMP to identify the HAN customers needed to meet the load reduction requirements. The HEMP then routes the demand response messages to the HAN gateways via the broadband connection. The HAN gateway passes the demand response events to the PCT(s) and LCSs prior to or at the start time of the event, depending on the event parameters. Once received at the PCT(s) and LCSs, the customer is automatically opted into event participation with the option to opt out of the event at any time prior to the end of the event. This opt-out/in decision can be made directly at the PCT(s) and LCSs or via the Customer Web Portal. Customer event participation information is then passed to the DERM via the HEMP to be used for post-event analysis and future demand response forecasting.

2.2.2.4.2 Post-Implementation Operational Issues

Following the initial integration, testing and deployment of the HANs, numerous post-implementation operational issues needed to be considered and mitigated. These issues included the following:

- Device Firmware had to be upgraded on all HAN devices during the second HEMP platform upgrade to fix various bugs and functionality issues. This was performed via the broadband connection, and this had no impact from a customer point-of-view. Also, due to issues with the HAN inventory PCTs having a higher rate of provisioning issues on their older firmware version, a decision was made during the HAN deployment to use PCTs from the Stand-alone PCT inventory, as they were on a newer firmware version.
- A successful HAN installation process requires a carefully planned set of coordinated steps between the device installer and the customer service representatives performing the device provisioning to the SmartMeter. The majority of issues encountered during the

device installation process were due to the steps not being completely in the correct order. When the process was not followed properly, issues would arise with devices joining improperly or not joining the network at all. Typically, this required resetting the SmartMeter HAN and restarting the provisioning process again. Occasionally, the devices had to be replaced all together.

- Customer broadband connectivity issues prevented KCP&L from calling on many HAN PCTs for DR events, whereas the Stand-alone PCTs were more reliably called-upon due to the AMI backhaul used for DR messaging.

2.2.2.4.3 Lessons Learned

Throughout the deployment and daily operation of the HANs, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- Broadband internet access was lower than expected among customers in the project demonstration zone, thus customer enrollment and participation in the HAN program turned out to be lower than initially anticipated.
- The number of compatible HVAC systems was lower than expected among customers in the project demonstration zone, thus customer enrollment and participation in the HAN program turned out to be lower than initially anticipated. Many homes either had non-central heating/cooling (e.g. window air-conditioner) or had systems that were not compatible with Tendril's thermostat. In some instances, KCP&L utilized an "add-a-wire" kit to enable compatibility between the Tendril thermostat and the customer's 4-wire HVAC system. Often times, a customer would be interested in signing up for the HAN program, but would be disqualified during the pre-installation screening or at the in-home visit due to these incompatibilities.
- Customer broadband connectivity issues prevented many HAN PCTs participation in DR events. If the utility DR program is going to rely on the customer broadband and Wi-Fi network, the utility needs to implement a proactive HAN monitoring and initiate customer contact to restore HAN communications so that DR devices are available to participate in events.
- 120V and 240V load control devices were not differentiated within the HEMP reporting mechanism, due to both devices falling under the same ZigBee device class. This made it difficult to differentiate between these two types of devices without consulting additional customer enrollment information in another system.

2.2.2.5 Time-of-Use Rate

One of the objectives of the KCP&L SGDP was to leverage pilot smart grid technologies to evaluate the effectiveness of time-of-use rates (TOU) on customer usage patterns. As a result, KCP&L designed and implemented an aggressive residential pilot TOU rate and offered it to all qualifying residential customers within the project area.

2.2.2.5.1 Build

Following regulatory approval in December 2011, KCP&L's TOU Pilot tariff went into effect on January 1, 2012. The systems interfaces and configurations were deployed during May/June 2012 and the first customers were enrolled effective with their bills at the beginning of June 2012. Over the course of this initial Summer Season, a total of 68 customers enrolled. Four of the customers have since exited the program with two customers moving out and two customers withdrawing as they had determined it wasn't the right fit for them.

System implementation included the following components:

- CIS - Rate and measuring component setup in CIS
- MDM - Configuration of the TOU calendar and rates
- SmartGrid Middleware - Deployment of the Pull Billing Interface and the TOU Register Read Calculator
- HEMP – interface and rate changes to transmit TOU data to the Tendril back office systems as well as the price push to the meter via the AHE

The project also developed an enrollment/cancellation process jointly with the SmartGrid Support Team and Billing Services. Several training sessions were held with these teams to introduce the overall TOU program including the rate structure, customer benefits and business support processes. Ongoing customer support is provided on a day-to-day basis by the SmartGrid Support Team. The IT team is engaged in production operational support of the various system interfaces to ensure that they are transferring and processing the necessary meter read and billing data correctly. The Billing Services team has roughly a five to seven day window of time each month when the SmartGrid Bill Cycles (3-7) are billed; during this timeframe, they review the bills for errors and also manually add the TOU bin detail to the bills for printing.

2.2.2.5.1.1 Tariff Design and Details

In designing a pilot TOU program, the project team established the following primary objectives:

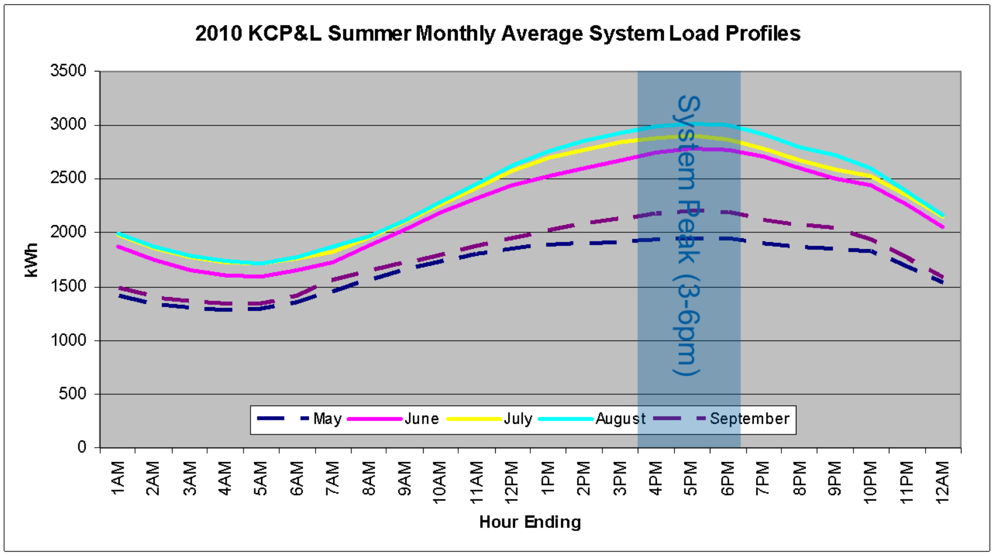
- Evaluate the effectiveness of smart grid technology to enable a TOU rate implementation
- Inform and educate KCP&L customers on the time-varying costs to supply electricity
- Use aggressive rate design to provide valuable learning to KCP&L and the industry with regards to customer behavior and response to price signals
- Implement a simple rate structure that could easily be understood by customers and that could be billed through KCP&L's legacy billing system without major modification
- Utilize effective rate design to provide load reduction during both the KCP&L system and typical residential customer peak load periods

In accordance with the stated objectives above, customer historical preference, the size of the eligible customer pool and some technical limitations with the existing KCP&L billing system, the project team settled on a simple yet aggressive TOU rate structure. This rate consists of two distinct pricing periods, a relatively short peak price period with a noticeably increased price and a discounted price the remainder of the day, effective on non-holiday weekdays throughout the summer months.

Once the general structure of the rate was established, the project team collaborated with various departments to analyze relevant data and develop an effective revenue neutral rate design that met the stated objectives.

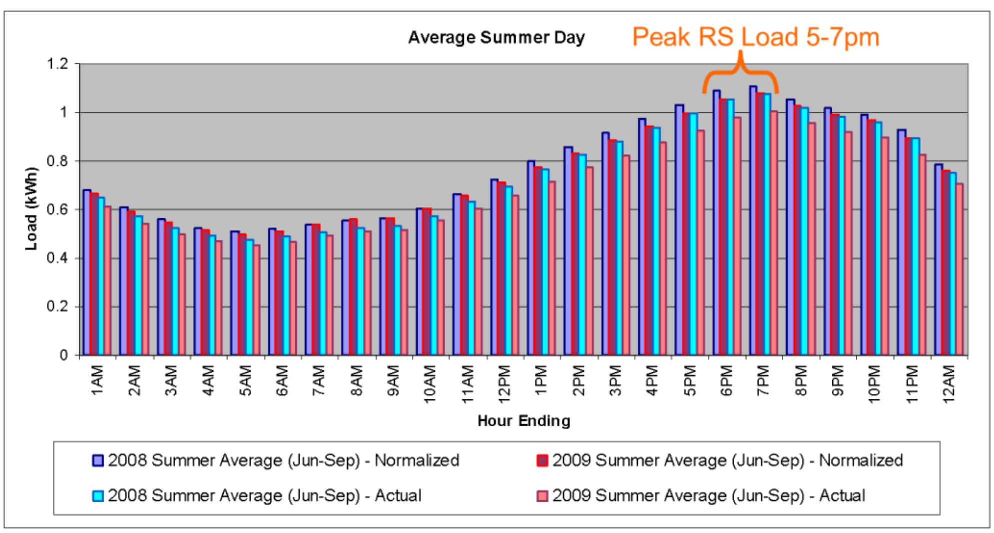
The first step was to investigate historical average daily summer system load profiles. As shown in Figure 2-31, the KCP&L system summer load profile is elevated yet relatively flat with a broad peak period centered on the 4:00-5:00 pm hour. The data shown consist of average monthly weekday hourly load for the aggregate KCP&L system.

Figure 2-31: KCP&L Summer Monthly Average System Load



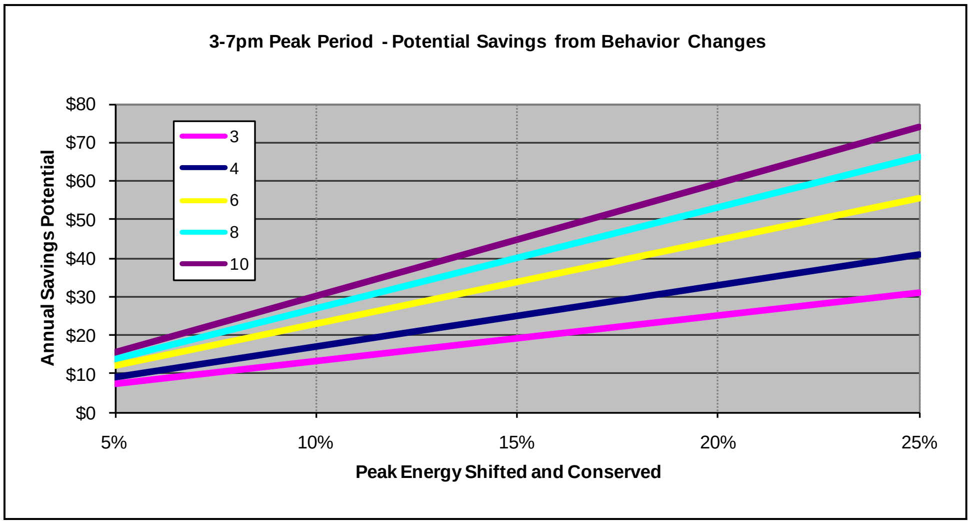
The second step was to investigate historical average residential load profiles. Figure 2-32 summarizes typical summer residential load profiles for customers in and around the project area. Peak residential loads occur later in the day, centered on the 5:00-7:00 pm hours. As a result from assessing both system and residential load profiles, the project team settled on a four hour peak period from 3:00-7:00 pm.

Figure 2-32: KCP&L Summer Average Residential Load



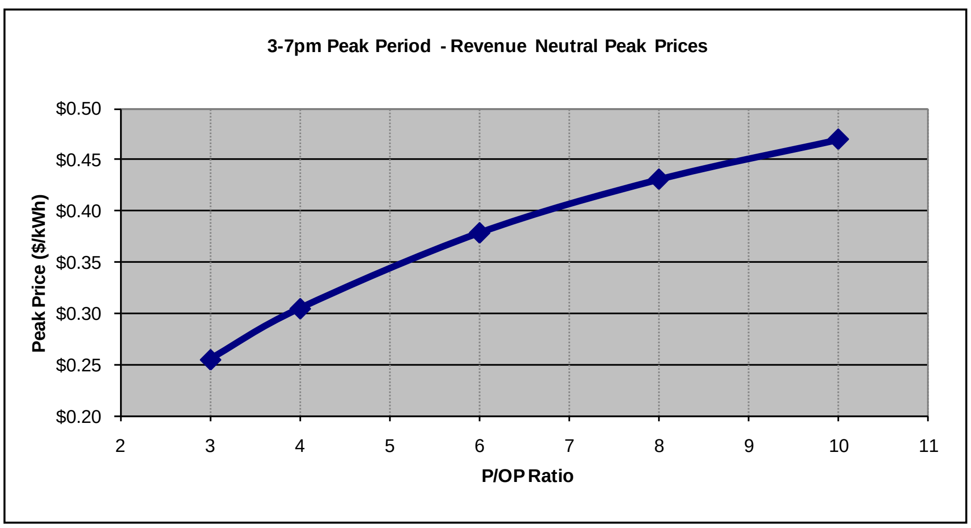
Next, the project team evaluated numerous revenue neutral price options within the determined rate structure to investigate price risk versus customer savings potential. Figure 2-33 summarizes the potential customer savings associated with the amount of peak energy shifted for five targeted peak-to-Off-Peak price ratios (3x, 4x, 6x, 8x, and 10x).

Figure 2-33: Customer Savings Potential in Various Revenue Neutral Price Options



While price ratios of 8x and 10x offer the most savings potential to customers, Figure 2-34 shows they require aggressive peak prices of over $0.40/kWh in order to maintain revenue neutrality in this rate structure. Therefore, the project team settled on a 6x price ratio which still offers an unprecedented regional rate option expected to provide valuable customer response learning.

Figure 2-34: Peak Price in Various Revenue Neutral Price Options



A revenue neutral TOU rate with 6x price ratio and four hour peak period from 3:00-7:00 pm resulted in peak price of $0.3784/kWh and Off-Peak price of $0.0631/kWh which represents a significant discount relative to the typical standard rate price of approximately $0.12/kWh from which participating customers would be switching. Additionally, an Off-Peak period of twenty hours offers significant flexibility and energy shifting potential to maximize this discounted Off-Peak price. A summary of these rate details is shown in Table 2-10.

Table 2-10: Pilot TOU Rate Details

Peak Period:	**3:00 – 7:00 pm**
Peak/Off-Peak Price Ratio:	**6x**
Summer Peak Price:	**$0.3784/kWh**
Summer Off-Peak Price:	**$0.0631/kWh**
Winter Rates:	**Declining Block**
Summer Dates:	**May 16 – Sept 15**
Customer Charge:	**$9.00/mo.**

Along with the rate structure and pricing described above, the following business rules were determined by KCP&L and the project team:

- Voluntary TOU rates only affect summer pricing. During winter, customers revert back to standard winter rates equivalent to standard flat rate
- TOU rate is available to both standard and all-electric customers
- Customers with dual meters are not eligible
- The TOU rate will expire at the end of the SGDP, December 31, 2014
- Customers may sign-up anytime throughout the year; however, the rates will not be affected until the first day of their next billing cycle
- Customers may exit the program at any time; however, they cannot re-join at a later time
- Upon request, KCP&L will credit customers for losses incurred by the pilot TOU rate relative to standard rate treatment for the current and previous billing cycles only

2.2.2.5.1.2 AMI Capture of Meter Read Interval Data

A foundational element of KCP&L's TOU program is the ability of the Landis+Gyr AMI meters to collect and transmit 15-minute interval data that includes date and timestamp information. On a typical day, the meter will capture 96 15-minute intervals with the initial interval running from 12:00:01AM – 12:15:00AM and the final daily interval running from 11:45:01PM – 12:00:00AM. These intervals are transmitted on a regular basis to downstream systems, including the MDM, for further processing. The AMI meters are all set up generically to collect this 15-minute interval data along with the regular daily register read value; a custom metrology solution was not required for TOU due to KCP&L's leveraging of the capabilities of the MDM and SmartGrid Middleware as outlined below.

2.2.2.5.1.3 MDM Usage of Meter Read Interval Data

The 15-minute interval data collected by the AMI system is stored in the eMeter EnergyIP MDM hosted by Siemens. The MDM provides two major capabilities that are critical for TOU: usage framing and billing determinant generation.

Usage framing sums up a customer's interval data over a specified period of time into a total usage amount for that period and stores it in the appropriate "bin". During the Summer Season, on non-holiday weekdays, the MDM sums all 16 of a customer's 15-minute interval values between 3PM-7PM to create a "peak" usage bin and the remaining 80 daily interval values between 12AM-3PM and 7PM-12AM to provide an "Off-Peak" usage bin. For weekends and holidays, all 96 daily intervals are added to the "Off-Peak" total. During the winter, all usage is added to the "Off-Peak" bin.

KCP&L also uses the MDM to deliver billing determinant information to the CIS using a modified version of the MDM's "Pull Billing" method where the CIS makes the request for data to the MDM and receives the necessary response back. Framed usage is retrieved on a daily basis via an "off-cycle", "informational" request to the MDM Pull Billing interface and is returned in "peak" and "Off-Peak" bin values.

2.2.2.5.1.4 KCP&L SmartGrid Middleware (incl. TOU Register Read Calculator)

KCP&L's legacy CIS currently receives register read values from a variety of metering systems including both AMR and AMI to bill customers. To support integration of these multiple systems, KCP&L has deployed a custom, in-house middleware solution that collects and stores daily register read values from all meters across the territory and normalizes the data to feed to CIS. For integration of the SmartGrid AMI meters, KCP&L added a SmartGrid specific component to the middleware which in turn required an additional enhancement to support TOU billing: the TOU Register Read Calculator.

The TOU Register Read Calculator translates the daily peak and Off-Peak usage values retrieved from the MDM into a daily dial read, effectively creating a virtual dial for each of the TOU bins: summer On-Peak, summer Off-Peak and winter Off-Peak. These register read values are then fed into the CIS following the normal meter billing process when needed for monthly bill cycle processing. In addition to the translation from usage values to register values, the calculator provides some additional important capabilities. It provides error tracking and reporting capabilities for use by the IT team and AMI Analyst. It converts AMI- and MDM-provided decimal values to integer values for the CIS; the AMI and MDM systems provide values with up to four decimal places – i.e. 12345.1234. It also supports the accounting requirement that the sum of the TOU kWh bin values match the billed kWh value; this true-up capability is critical due to the decimal-to-integer translation necessary as well as any decimal/integer gap that may occur on a customer's initial enrollment.

2.2.2.5.1.5 CIS/Billing Updates

Additional CIS coding was not required to support TOU billing. Existing system capabilities were leveraged to enable the setup of the virtual register dials noted above in the CIS for billing without requiring a physical meter exchange. During the enrollment process, the meter is temporarily deactivated from the customer account during which time it has the three TOU measuring components for summer peak (SKP), summer Off-Peak (SKO) and winter Off-Peak (WKH) added and activated on the customer's meter. Once these measuring components are added, the meter is reactivated on the customer account and once the customer is moved to the 1TOUA/1TOAA rate, including an initial install read, they are then active on the TOU Billing Pilot Program.

2.2.2.5.1.6 TOU Tendril

To aid customers in more effectively participating in the TOU program, various cues are provided to participants who are users of the HEMP and/or KCP&L provided IHDs. Upon enrollment, KCP&L pushes a rate change via the existing MQ interface to the Tendril back office system that supports the HEMP which causes the Portal to display their 1TOUA/1TOAA rate instead of the previous 1RS1A/1RS6A rate. It also changes the pricing information in the Portal to reflect the TOU prices (outlined in the Tariff section above). The rate change on the customer record also triggers the Portal to display the appropriate TOU pricing based on the season and time of day.

A similar solution was implemented to ensure that the correct pricing amount was pushed out to the AMI meters for display on the IHD. The existing TTM (Tunnel Text Message) interface that pushes customer pricing details out to the meters was updated to send the TOU Summer Peak pricing as a "pricing event" to the meter so that the peak rate will display on the IHD from 3PM-7PM and then revert back to the Off-Peak price once the TOU period ends each day.

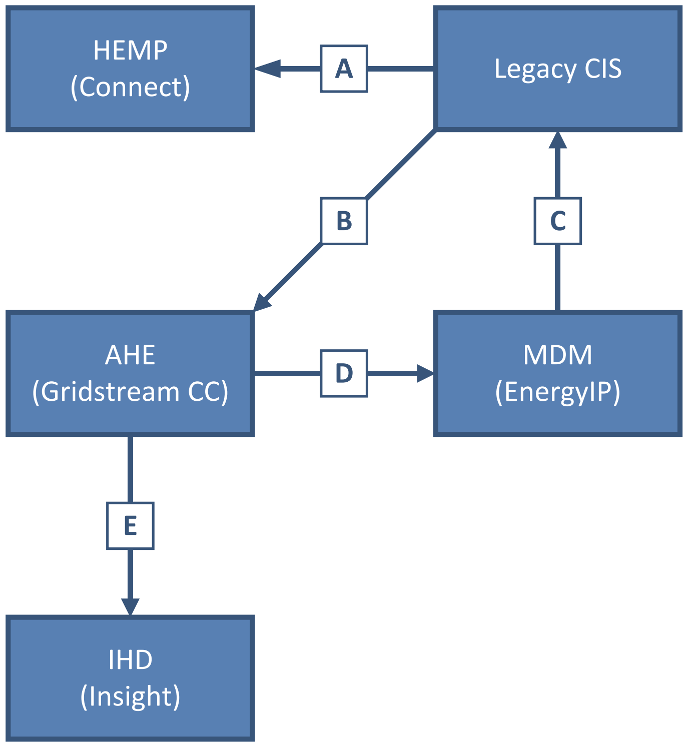
2.2.2.5.1.7 Customer Printed Bill

The final visual cue provided to the customer is the billing detail received on their monthly printed (or PDF) bill. At the present time, this is being added manually by the Billing Services team through use of Adobe Writer to edit each monthly customer bill and to add the three lines displaying their register dial values and usage totals for each of the three TOU bins. This is expected to be automated as part of KCP&L's upcoming OneBillPrint Project.

2.2.2.5.2 Integration

An overview of TOU system-to-system interfaces and applicable messages is illustrated in Figure 2-35.

Figure 2-35: KCP&L SmartGrid Demonstration Project TOU Integration



The integration touch points for the TOU implementation are as follows:

A. Consumption Pricing messages containing 1TOUA/1TOAA rate information pulled from CIS and sent to HEMP via a REST call executed by MQ Broker. These messages are sent once a customer enrolls in the TOU program to update the customer portal with real-time per-kWh consumption pricing information.
B. Consumption Event Pricing messages initiated from CIS to AHE. These "event pricing" commands are sent daily to update per-kWh consumption pricing information on customer IHDs during the TOU peak hours.
C. Billing Determinant data initiated from MDM to CIS. This data is requested daily by CIS using MDM's "Pull Billing" interface and is used to update CIS with proper billing determinant information for TOU customers including summer On-Peak, summer Off-Peak, and winter Off-Peak consumption data.
D. Daily Register and Interval Read data initiated from AHE to MDM. This is California Metering Exchange Protocol (CMEP)-formatted data sent hourly to be stored in the meter usage data repository and used for TOU billing determinants.
E. Consumption Event Pricing messages containing 1TOUA/1TOAA rate information initiated from AHE to IHDs. These messages are ZigBee SEP 1.0-formatted "event pricing" messages sent daily to the IHD via the AMI network through the SmartMeter using the ZigBee SEP 1.0 "publish price" command to update customer IHDs with real-time per-kWh consumption pricing information during the TOU peak hours.

2.2.2.5.3 Post-Implementation Operational Issues

Following the initial integration, testing and deployment of the TOU program, numerous post-implementation operational issues needed to be considered and mitigated. These issues included the following:

- A special, daily "event" pricing had to be set up to create a pricing event from 3-7 PM on the IHDs to display the correct price during TOU peak hours. This was needed because KCP&L chose not to use the TOU-specific registers within the SmartMeter because this would have required special programming for each individual TOU customer meter. The "event" pricing required a special pricing signal to be sent to the SmartMeters during overnight hours, so that all SmartMeters would be ready to push the pricing event to their IHDs during peak hours.
- The FlexSync interface from CIS+ to MDM has frequent errors in synchronizing customers; this sometimes impacts TOU enrollments by not updating the MDM in a timely manner to trigger the TOU usage framing; this also has caused delays in meter exchanges for TOU customers being processed properly which leads to gaps in usage; it's expected that with a new MDM/new CIS+ platform that are more tightly integrated this will be less of an issue.
- The custom Pull Billing interface that was written to support KCP&L's legacy CIS+ system experiences request failures that require constant monitoring and frequent manual submission of the requests to correct errors in the TOU usage being presented to CIS+; it is expected that with a new MDM/new CIS+ platform that are more tightly integrated this will be less of an issue.
- There have been several instances where meters have stopped reporting intervals or all reads; this has sometimes taken 1-2 months to correct in the field which then results in significant manual effort to recreate/estimate the missing TOU reads and feed them through the MDM and TOU Calculator processes.

2.2.2.5.4 Lessons Learned

Throughout the build, implementation, and daily operation of the TOU program, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- An additional enhancement was required within the SmartGrid middleware interface to CIS to support TOU billing. This TOU Register Read Calculator was required to convert usage data into register reads and feed the TOU data into CIS in a tolerable format for billing purposes.
- Overall, enrollment in the TOU program was higher than anticipated. TOU enrollment exceeded enrollment for both the Stand-alone PCT and HAN programs. As of October 2013, TOU enrollment was 131 customers.
- Legacy CIS+ system was less capable in supporting a billing program such as TOU that required customized inputs; the ability to provide this capability "out of the box" is being noted as a requirement and business case benefit for KCP&L's upcoming CIS+ replacement.
- Tight integration between the MDM and CIS systems was identified as a key business requirement for the selection of a new enterprise MDM platform as KCP&L expects to use the new MDM to support billing of ALL customers and not just the TOU customers; this was driven in part by KCP&L's experience with the SmartGrid TOU program.

2.2.3 SmartSubstation

The SmartSubstation subproject deployed a state-of-the art distribution SmartSubstation with an IEC 61850 substation protection network, a distribution data concentrator, human machine interface, GOOSE messaging, and distributed control and data acquisition components.

These various components were initially planned for simultaneous deployment. However, as the project progressed and KCP&L further assimilated the scope and complexity of this overall project, questions arose regarding the feasibility of the original intent to conduct one comprehensive configuration and test effort for all SmartSubstation functions. An analysis was performed to better understand the critical interdependencies between systems to ensure successful testing and deployment. The result of this analysis showed that complexity in the related systems would benefit from increased focus on narrower definitions of scope. To this end, and as pursued with each component system below, it was decided to break the configuration and deployment of the overall SmartSubstation into four phases. Each of the phases of work would include configuration and testing as applicable to the given system.

- Phase 1 – Substation Device Monitoring: All substation devices to be automated through the project (breakers, differentials, tap changers, etc.) were configured and installed at KCP&L's Midtown Substation as part of the Substation Protection Network. In parallel, preliminary efforts were conducted to deploy the Distribution Data Concentrator (SICAM) to establish preliminary communications for remote monitoring of substation device point changes. Point-to-point monitoring-only checkouts were conducted on all points for all substation devices to ensure proper communications from the devices.
- Phase 2 – Substation Device Control: End-state networking and configurations for the Substation Protection Network were deployed and stabilized. Point-to-point monitor and control checkouts were conducted on all points for all substation devices to ensure proper communications to/from the devices through to the Distribution Data Concentrator (SICAM). HMI capabilities were configured, tested, and deployed to the substation control house.
- Phase 3 – Substation DCADA: Activities highly synchronized with SmartDistribution, once the advanced application algorithms were proven out via centralized First Responder test efforts in the DMS, the algorithms were ported to the DCADA for autonomous substation control. Further controlled tests were performed to gain confidence in the system and establish initial configurations for automatic operation (particularly with VVC).
- Phase 4 – Substation GOOSE Messaging: Initial configuration efforts for GOOSE were pursued throughout earlier phases, but deployment and real-world testing of the protection schemes were pursued independently upon a stabilized base of previously deployed capabilities.

Another key takeaway from the initial implementation analysis was the need to establish and maintain several integrated environments to ensure that functionality was safely segregated for forthcoming development and testing efforts. Due to the complexity of integrating systems within each of these environments, the effort to set these up was commenced early to ensure their readiness as needed.

- Vendor Environment: The first and most basic environment was the vendor environment. The UI/CAD, D-SCADA, and SICAM DDC applications were installed on KCP&L owned servers that were sent to the Siemens facility for initial configuration. In addition, sample substation controllers were also provided for vendor use. All hardware was extensively used to establish initial configurations and ensure they were working under controlled conditions.
- Lab Environment: The second and more complex environment was the lab environment. It was initially setup to augment the vendor environment, as sample field devices were setup and connected to a lab dedicated network which was interfaced with the servers of

the vendor environment for preliminary tests. Later in the project lifecycle, the sample substation devices were transferred back to KCP&L's facility and additional KCP&L procured servers were then setup in the lab to establish a stand-alone environment; the connection to the vendor environment was severed. By that point, the lab also had integration with numerous other systems to more robustly mimic demo and was used to test out preliminary integration configurations.

- Demo Environment: The final and most complex environment was the demo environment. This was KCP&L's real-world environment where the systems were supported by redundant servers, configured for full integration with other systems, and connected to all of KCP&L's smart grid devices deployed to the substation and certain highly automated distribution feeders. Redundant HMI, DCADA, and SICAM DDC servers were deployed in the Midtown Substation Battery Control Enclosure for this environment. As these devices result in real-time, real-world distribution network changes, special care was taken to ensure that no negative consequences resulted from the team's efforts when testing in the demo environment.

The following subsections summarize these SmartSubstation component deployments.

2.2.3.1 Substation Protection Network

The Midtown Substation Protection Network is an Ethernet-based substation control network utilizing the IEC 61850 network architecture. Because substation protection and control networks are deployed in harsh environments and transport critical data, the network was designed to have high availability and low latency, providing fast, reliable communication between networked devices. Additionally, the networking equipment is environmentally hardened, as it is expected to operate across extreme humidity and temperature ranges.

2.2.3.1.1 Build

The high level network architecture was shown in Figure 1-21, Midtown Substation Protection and Control Network Architecture. In general, the IEC 61850 network consists of redundant 1 Gbps Ethernet backbones routed throughout the substation. These backbones interconnect remote primary and backup Ethernet switches installed in various switchgear enclosures to main Ethernet switches located in the main control enclosure. Protective relays, equipped with redundant Ethernet ports, connect to the appropriate primary and backup remote switches using 100 Mbps Ethernet. The following sections provide a summary of the tasks performed to implement and deploy the substation protection network.

2.2.3.1.1.1 Network Design

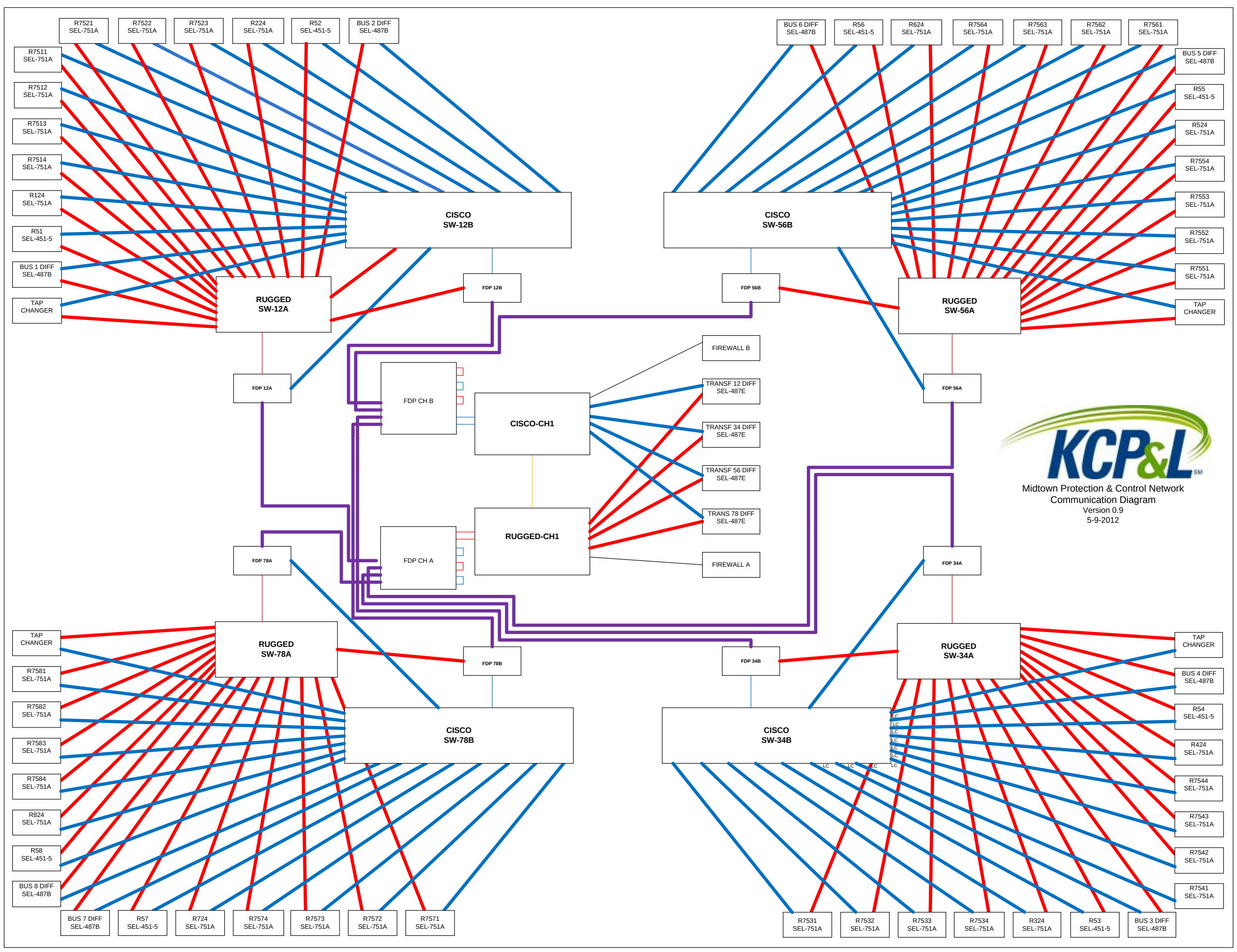
The IEC 61850 network was designed as a redundant Ethernet ring architecture. Ring architectures allow for self-healing networks, increasing availability and reliability. The Ethernet switches comprising the network are arranged in rings, providing redundant pathways between two points in the network via the Ethernet backbone. This configuration protects against loss of communication between devices due to failure of a communication link or loss of an intermediate switch. Loss of communication only occurs when there is a failure in the edge switch to which one of the two communicating devices is connected. To further increase reliability, redundant rings were deployed. This allows devices with redundant Ethernet interfaces to take advantage of a standby Ethernet network, reducing the probability of a loss of station control due to failure of any single piece of network equipment. This redundant ring configuration eliminates single points of failure for all Ethernet hardware when the communication devices are configured in fail-over mode. Figure 2-36 provides an overview of the substation protection and control network that was implemented. The complete IEC 61850 Communications Network design document is included in this report as Appendix D.

2.2.3.1.1.2 Lab Testing

Ethernet switch testing was conducted in a lab environment to verify the configuration and performance of a multivendor, IEC 61850 LAN. Cisco CGS 2520 and Ruggedcom 2100 Ethernet switches were selected by KCP&L for the Midtown Substation 61850 LAN trial. This section provides a summary of the network lab testing that was performed. The complete IEC Switch Test Results document is included in this report as Appendix E.

The topology KCP&L selected for the Midtown Substation 61850 LAN trial was tested in three parts: the Cisco ring, the Ruggedcom ring, and the combined rings. There were two types of tests run on the network to determine network convergence following two types of failures that can occur on an Ethernet LAN: port failures and link failures.

Figure 2-36: SmartSubstation Protection and Control Infrastructure



The primary purpose of the inter-vendor testing was to determine the performance of using the proprietary Layer 2 loop-reduction protocols offered by each vendor. In addition to the industry-standard IEEE 802.1w, Rapid Spanning Tree Protocol (RSTP), each vendor offers a proprietary algorithm with faster than RSTP performance. Cisco offers Resilient Ethernet Protocol (REP), which is designed to interoperate with RSTP. Ruggedcom offers Enhanced Rapid Spanning Tree Protocol (eRSTP), which is designed as an extension of RSTP and offers backwards compatibility with RSTP.

Throughout the testing, intra-vendor performance was mostly consistent with each of the vendors. There was a reproducible anomaly with specific failure scenarios with REP in the Cisco ring. Other convergence times in the Cisco ring were in the sub 50 ms range. Cisco RSTP convergence was very consistent with repair times, but the convergence times were never under 50 ms, and typically more than 100 ms. Additionally there was difficulty configuring REP to interoperate with RSTP in an intra-vendor setup, so there was no testing conducted in an inter-vendor configuration.

Cisco showed consistently better times when failing a single relay port by approximately 120 ms on average with an SEL-451. There were no other relays available for comparison so this could be an issue with the SEL-451 specifically.

The Ruggedcom implementation of eRSTP is very consistent with convergence and repair times and was across every test that was run on the Ruggedcom and combined rings. Both convergence and repair times on each test were within 1 ms of every other respective convergence and repair time for each configuration.

VLAN configuration had to be adapted, and an extra VLAN was added to accommodate the way Cisco handles tagged traffic going into a trunk port with a native VLAN. Although the workaround poses no operational issues, the difference in the way each manufacturer handles both tagged and untagged packets on a trunk port caused some issues during the initial configuration.

2.2.3.1.1.3 IED Replacement

KCP&L began replacing the Midtown IEDs in February 2011. The devices were replaced in a systematic manner, one switchgear or transformer at a time. Devices associated with five switchgear were replaced in 2011, three switchgear were replaced in 2012, and all four transformers were replaced in 2012. Sixty three total IEDs were installed in the Midtown Substation, as described in Table 2-11.

Table 2-11: Substation IEDs Installed

IED	Model	Monitor/Control	Quantity
Bus Main Breakers	SEL-451-5	Monitor Only	8
Tie Breakers	SEL-751A	Monitor Only	8
Transformer Differential Relays	SEL-487E	Monitor Only	4
Bus Differential Relays	SEL-487B	Monitor Only	8
Feeder Breakers*	SEL-751A	Monitor Only	20
Feeder Breakers*	SEL-751A	Control	11
Load Tap Changers	Eberle REG-DA	Control	4
**11 of the 31 circuits in Midtown Substation feed the Green Impact Zone, or the project area. The feeder breakers for these circuits have monitor and control capabilities, whereas the non-smart grid feeders can only be monitored.*			

The point of demarcation between KCP&L's existing transmission EMS and the SGDP DMS is the substation feeder breaker. Both systems have monitor and control capabilities of these devices. The feeder breakers will continue to send data to the existing Midtown RTU, but the 11 smart grid feeder breakers will also send information to the new substation data concentrator, the SICAM. In order to avoid having controls come from both the EMS and the DMS, a control authority selector has been added to the EMS so that the distribution operators can toggle control between the two systems.

Although the Midtown Substation devices have the necessary IEC 61850 Configured IED Description (CID) files loaded, the IEC 61850 GOOSE messaging hasn't been activated as of yet. Currently, the devices are communicating via 61850 MMS messaging to the SICAM, but they won't perform the peer-to-peer GOOSE communications until a multi-bus test can be conducted.

2.2.3.1.1.4 Fiber Installation

The fiber installation occurred during April and May of 2012. The Midtown Substation physical infrastructure is laid out in a star configuration with one cable trench for each bay in the ring bus. These trenches extend from the control enclosure, which is in the center of the substation, out to each switchgear enclosure. Two twelve-fiber, single-mode fiber optic cables were installed between each switchgear enclosure and the main control enclosure. Fiber distribution panels (FDPs) were installed in each switch location, as well as within the control enclosure. At Midtown Substation, it was impractical to install new conduit directly between each switchgear enclosure to create a truly physical ring, so the Ethernet switches were connected in a ring by patching in the FDPs located in the control enclosure. These new fiber optic cables were installed in the existing cable trench with other control cable.

2.2.3.1.1.5 Switch Installation

The network switches were also installed in April-May 2012. As part of the pilot, the Midtown Substation was retrofitted with a redundant Ethernet communications network with hardware from two switch vendors (Ruggedcom and Cisco) for protection operation. Using two vendors allowed KCP&L to evaluate the products simultaneously to determine which was best suited for substation protection and control networks. Each vendor's equipment was used to build a ring in the substation, and each relay has an interface connected to both rings. The rings are interconnected at two points for redundancy. The core ring was built using gigabit fiber connections. The relays each have two 100-Mbps Ethernet interfaces used in a hot standby configuration. Each vendor has its own proprietary protocol for blocking loops from forming in the Ethernet network while recovering from a link failure in less than 50 msec. In between the rings, rapid spanning tree protocol was used to provide failover in less than 250 msec.

2.2.3.1.1.6 Production Testing

After the network was physically installed, the Network Services team conducted testing on the production network. The testing occurred in October, 2012, and it included the following tests:

- Verify Baseline Control House L2 Traffic Flow
- Verify Baseline Battery Control House L2 Traffic Flow
- Verify Baseline Cisco Switch House L2 Traffic Flow
- Verify Baseline Ruggedcom Switch House L2 Traffic Flow
- Ruggedcom eRSTP Devices interact with Cisco MST Devices via RSTP
- Control House Link Failure 1
- Control House Link Failure 2
- Battery Control House Link Failure
- Cisco Switch House Link Failure 1
- Cisco Switch House Link Failure 2
- Ruggedcom Switch House Link Failure 1
- Ruggedcom Switch House Link Failure 2
- Ruggedcom Switch House Link Failure 3

All test cases passed, and upon completion, the substation protection network was put into service.

2.2.3.1.2 Post-Implementation Operational Issues

For the most part, the substation protection network has functioned smoothly thus far. The team has only encountered two post-implementation operational issues with this portion of the project.

2.2.3.1.2.1 Ruggedcom Switch Replacement

Although the Ruggedcom and Cisco rings were functioning sufficiently, the KCP&L team decided to move forward with a Ruggedcom replacement. From the outset of the SPN design, one of the major reasons for using two vendors for the initial implementation was so that KCP&L could evaluate multiple manufacturers. After a year of operation using this mixed-vendor network, KCP&L's Network Services group recommended a change to the production network. They suggested replacing the Ruggedcom switches with Cisco switches for the following reasons:

- No "accounting" functions on Ruggedcom switches: There is a networking standard called AAA which stands for Authentication, Authorization, and Accounting. The Ruggedcom switches can perform the Authentication and Authorization pieces of AAA, but not the Accounting function. The Cisco switches can perform all three functions of AAA and are currently passing NERC/CIP audits in the KCP&L production environments. Accounting in the network environment provides logs of any user activities performed on the switch by users that have been authenticated and authorized. These logs provide evidence that is used to fulfill a NERC/CIP requirement.
- Banners: Login banners are presented to anyone attempting to connect to the management interfaces of the network devices to notify any potential users that they are responsible for what they do when logging in to a KCP&L device and that unauthorized access is prohibited. KCP&L's current standard is to present a banner prior to login and also after login. The Ruggedcom switches do not allow for a login banner to be presented prior to login, but rather only after a user has logged in to the device. This lack of functionality would require an exception to be filed if the substation were to fall under the purview of current NERC/CIP standards.
- Workflow and Procedures: Since the protection hardware is located in the switchgear buildings at the substation, the Network Services team cannot install or replace the physical switch hardware. This process can be straight forward and simple with the Cisco hardware, but the Ruggedcom hardware requires a more highly coordinated effort between Network Services and the KCP&L relay technicians.
  - **Cisco:** Spare hardware can consist of one switch, many SFPs (small form-factor pluggable), and many memory cards. The memory cards can be labeled to match the names of the switches. When a switch replacement is required, the relay technician simply inserts the appropriate memory card into the spare switch that contains the proper configuration for the switch that is being replaced. The process is simple enough that the relay technicians won't need direct assistance from the Network Services team. The Cisco switches also use SFPs (port adapters) to generate the optical signals for each independent connection to the IEDs. The independent, field replaceable units can be replaced without swapping out the entire switch. Additionally, the SFPs are hot swappable and can be replaced without powering down the switch.
  - **Ruggedcom:** Spare hardware would consist of spare switches stored at Network Services' location, so that Network Services has physical access to them for initial configuration. The spare switch would require configuration by the Network Services team through the use of TFTP (trivial file transfer protocol), and the configuration would vary depending on which switch needs to be replaced. Then, the switch would be delivered to the relay technician for installation. In the event of a single access port failure, the complete switch would need to be replaced.
  - **Reliability:** Running two switch vendors in the same substation environment presents concerns about multiple protocols being used in a single implementation. When both vendors are used, Reliable Ethernet Protocol (REP), Enhanced Rapid Spanning Tree (eRSTP), and Rapid Per VLAN Spanning Tree (RPVST) protocols are all utilized. When the entire network utilizes Cisco equipment, then only REP is used.

2.2.3.1.2.2 Compromised Fibers:

The other post-operational issue pertaining to the substation protection network has been a few compromised fibers. In 2013, a fiber connected to tap changer 5/6 failed and the communications didn't switch over to the other ring. This was a fortunate issue, as KCP&L didn't realize that the tap changers weren't properly set up to have redundancy. After resolving the issue with the fiber, KCP&L also worked to configure the tap changers to function in a redundant mode.

During HMI retesting in November 2013, the fiber between switches SW-34A and SW-56A was deemed problematic. After investigating the issue, KCP&L replaced the faulty fiber. This resolved the issue.

2.2.3.1.3 Lessons Learned

Throughout the build, implementation, and daily operation of the SPN, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- Pros and Cons of Multivendor SPN – KCP&L learned a lot on this portion of the project in regards to a multivendor implementation of the redundant network. In general, KCP&L learned that it is feasible to design, construct, and run a multivendor substation protection network, but there are certainly drawbacks to this approach. As described in the sections above, the hybrid approach yields uncertainty in regards to functionality and failover time. Testing out the proposed network architecture in a lab environment was critical prior to deployment of the networking equipment in the production environment.
- Ownership of the SPN – As KCP&L designed, tested, and built the Midtown Substation SPN, it became obvious that this type of project was outside of any one department's normal set of tasks. The Substation Protection and Relay System Protection groups are very familiar with the IEDs, but they have minimal experience with local area networks. The Network Services personnel are well-versed with the actual network, but they typically have minimal experience with the IEDs, and they usually don't have access to the substations.

  From KCP&L's research and discussions with other utilities, it seems as though this issue is one that many utilities are currently facing. Some utilities are having the Network Services team take ownership of the IEC 61850 network, and some are adding this to the Substation or Relay System Protection team. Meanwhile, other utilities are creating a third, hybrid group that specifically addresses this mix of skill sets. For the SGDP, KCP&L has chosen to tackle this new domain with a coordinated effort between the Network Services, Substation Protection, and Relay System Protection groups.

2.2.3.2 Distribution Data Concentrator

Siemens' SICAM PAS was deployed as the DDC or communications gateway for the substation relays and field devices reporting through the Midtown Substation.

2.2.3.2.1 Build

The SICAM is one of Siemens commercially available utility products. By pursuing this "off-the-shelf" philosophy to the maximum degree possible, limited design and development efforts are required and the SGDP is provided the opportunity to evaluate the capabilities of existing products and technologies in meeting the emerging smart grid requirements. The following sections provide a summary of the development and configurations that were required to implement and deploy the desired DDC functionality.

2.2.3.2.1.1 Training

Training on the SICAM occurred from August 13, 2012 through August 16, 2012. This training was conducted by Siemens and it covered the basics of the system – loading devices, creating templates, mapping points to other interfaces, and basic troubleshooting. Additional training on the SICAM continued through the SICAM go-live and after it became operational.

2.2.3.2.1.2 Hardware Installation

KCP&L chose to implement redundancy for most of the critical systems in this project. The Distribution Data Concentrator is certainly considered a critical piece of hardware, so two SICAMs were rack-mounted in the Battery Control Enclosure, right next to Midtown Substation.

2.2.3.2.1.3 Substation Device Point Configuration

The process of loading the substation devices into the SICAM was a long and detailed endeavor. Once KCP&L chose all of the devices for use in Midtown Substation, they determined the data points that were desired for each substation device type. They started with the default maps (what is published by default by each device) and then added some additional data points to their list as desired. A complete listing of data and control points configured for each substation device are contained in Appendix F.

Next, the project team used SEL Architect (the relay vendor's configuration tool) to create the CID files. These files define the logical nodes for each device. These logical nodes are essentially groupings of data points for functional purposes. When a device reports or is polled, if one of these nodes is read, all of the associated data points in that node are also sent back to the concentrator. In addition to the logical nodes, the CID files also have reporting capabilities (frequency, integrity poll, whether or not they're buffered), deadband definitions for analog values, data types, how data is formatted. Lastly, the CID files include the IP address of the device.

In terms of naming the points, IEC61850 has a format that must be followed, so the point names were basically determined by default once the team determined the data to be sent from the device to the SICAM. The team also used the 61850 names for the ICCP naming, which is discussed further in the DMS UI/CAD and Distribution-SCADA Implementation sections.

Once the CID files for each device were created, the team loaded each one into the SICAM. Upon completion of each CID file load, the SICAM creates a device template. The device templates contain the information necessary to build the communication interface from the device to the SICAM. The SICAM then uses this template to build the device mapping, which contains the information necessary to build the communication interface from the SICAM to the DMS/DCADA/HMI. The team didn't have to select any points for alarming at the SICAM; rather, the SICAM is just a pass through for the alarms to get to I/Dispatcher.

Once the template and mapping is complete, the team selected the data points that they wanted to see on the 61850 client interface. This interface is used to determine what points are shown in the SICAM's Value Viewer, which is essentially the SICAM's GUI. Not all the points that are sent from the device to the SICAM need to be included in this interface – it can be just a subset of the original points transferred. Similarly, the team chose the subset of data points for the 61850 server interface. These points are sent to any upstream systems, such as the DMS, the DCADA, and the HMI.

The screenshot in Figure 2-37 shows some of the information that is brought in when a CID file is loaded on the SICAM for an IEC61850 device.

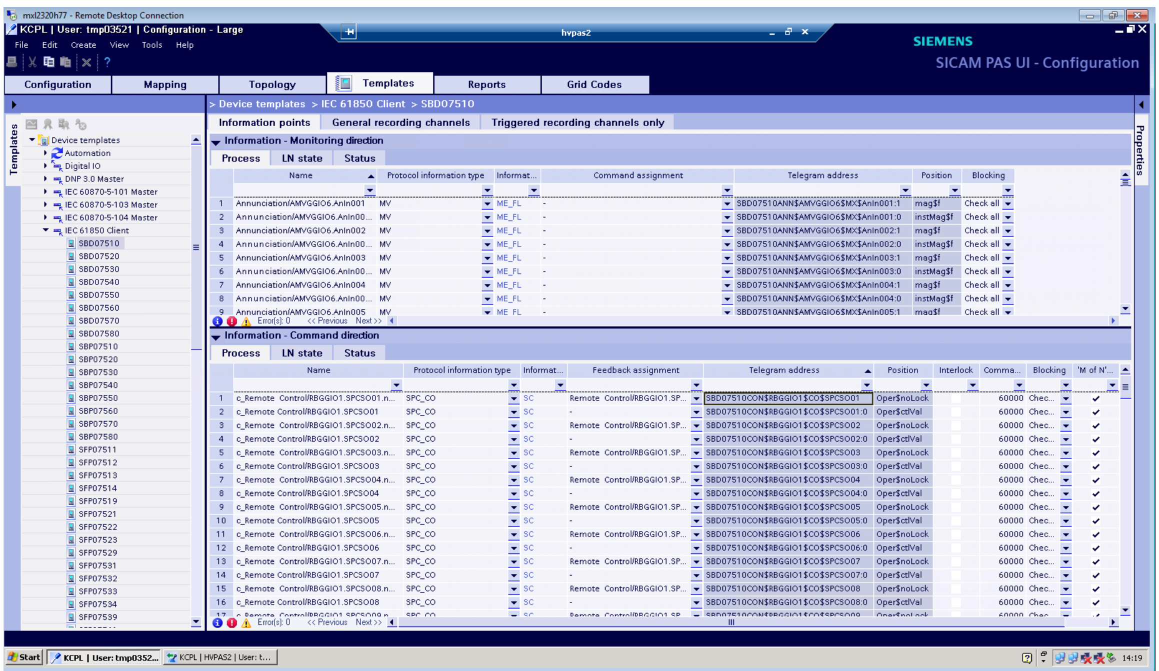
2.2.3.2.1.4 Field Device Point Configuration

The process of loading the field devices into the SICAM differs a bit from the substation devices. For the DNP3 field devices, no file is loaded on the SICAM; rather, the configuration information is all stored within the relay settings file on the device.

Similar to the substation process, the KCP&L team started by determining the desired devices for use in the field network, and then they determined the type of data that they wanted from each device type. The relay group then created the settings files for each device, including the DNP point set list as well as the protection settings. A complete listing of data and control points configured for each field device are contained in Appendix F.

In terms of device naming for the DNP3 field devices, the team tried to make the names as 61850-like as possible. Since the long-term goal was to use 61850 for communications to these field devices, the team wanted to make this is easy as possible later on. In some cases, the 61850 names weren't possible, but the team worked to get the names as close as possible. The team used the 61850 names for the ICCP naming, which is discussed further in the DMS UI/CAD and Distribution-SCADA Implementation sections.

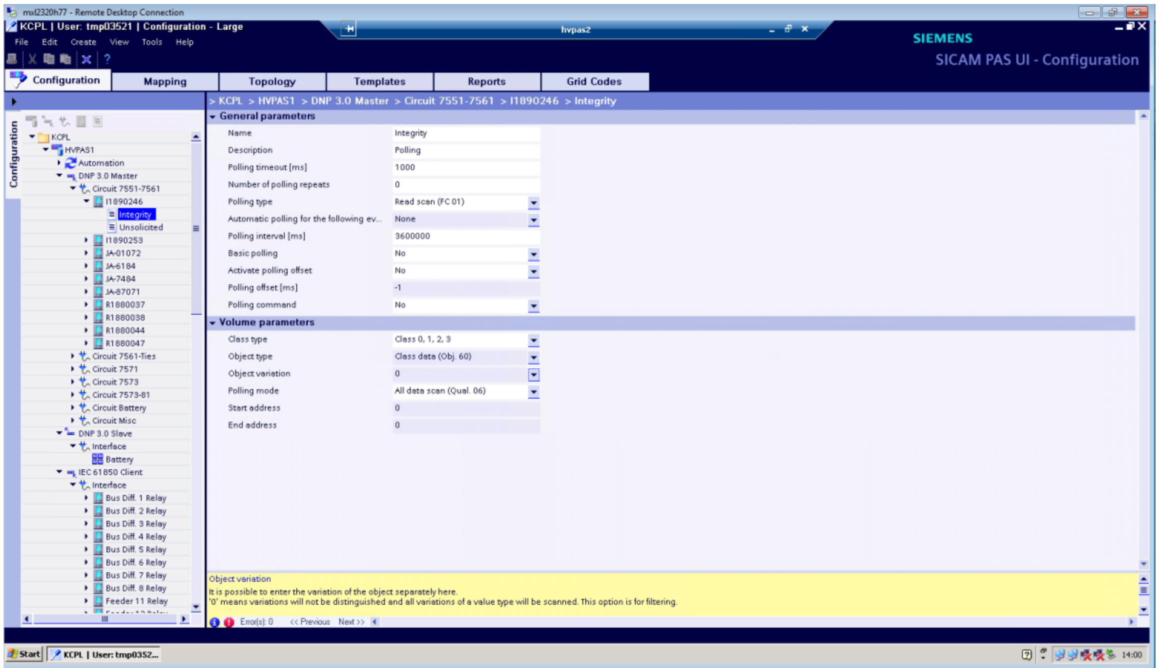
Figure 2-37: IEC 61850 Device Template on the SICAM



For the DNP field devices, the project team had to manually build the templates in the SICAM. To do this, they selected a subset of points, and then they matched those points between the settings file on the device and the points selected in the SICAM. DNP addresses and communications settings (IP address and port) need to match for this to function properly. For the mapping step, the SICAM basically uses the template that was created, but then the user has to select the points that are desired for Value Viewer as well as for upstream propagation. For the DNP devices, these interfaces are called DNP Master (these are the points displayed in SICAM Value Viewer) and DNP Slave (these are the points that are sent to upstream systems such as the DMS/DCADA/HMI). The team didn't have to select any points for alarming at the SICAM; rather, the SICAM is just a pass through for the alarms to get to I/Dispatcher.

The screenshot in Figure 2-38 shows some of the configuration that is needed when mapping a DNP3 field device.

Figure 2-38: DNP3 Device Configuration on the SICAM



2.2.3.2.1.5 Demonstration SICAM Implementation

For the Kansas City long-term environment, there were two SICAM implementations—the demonstration system implementation and the development system implementation. To begin the demonstration system implementation, Siemens first created the initial SICAM database through the points lists provided to them by KCP&L. They first programmed the IEC61850 and DNP3 devices to communicate to the SICAM through the IEC61850 Client and DNP3 Slave protocols on the SICAM server. Once the communication from SICAM to device was built, Siemens mapped the signal data to DMS and DCADA through the IEC61850 Server protocol, and to the HMI through its HMI interface.

Once the initial configuration was complete, Siemens invited KCP&L to their regional office in Minneapolis, MN to perform Factory Acceptance Testing (FAT). KCP&L performed FAT testing based on material provided by Siemens as well as additional test material developed by KCP&L. Upon completion of the FAT, KCP&L provided Siemens with a list of variances rated in severity; the more severe needing to be resolved prior to Site Acceptance Testing (SAT). Siemens worked to resolve the critical variances and deploy/test them. Eventually, the servers were shipped from Minneapolis to Kansas City. KCP&L then invited Siemens onsite for SAT testing. KCP&L conducted testing through the materials provided by Siemens, materials created by KCP&L, and any variances that were created in the FAT. Post SAT, Siemens worked to continue resolving variances through “Go-Live”.

2.2.3.2.1.6 Development SICAM Implementation

The implementation of the development SICAM was dependent on a working model in the demonstration instance. The database from the demonstration SICAM was migrated on to the development SICAM, so that the development SICAM was an exact copy of the demonstration instance. KCP&L then altered the communication settings within the development SICAM to allow it to communicate over the development network to other development servers and devices. The end result was a working development SICAM that communicated IEC61850, DNP3, and Siemens proprietary protocols data on an isolated smart grid environment.

2.2.3.2.1.7 Point-to-Point Checkouts

The substation device point-to-point checkout was conducted by four groups: KCP&L Relay, KCP&L Dispatch, KCP&L Smart Grid, and Siemens. KCP&L's Relay group was on-site to create any binary status events, monitor any analog data, and provide feedback on any device controls. KCP&L's Dispatch was responsible for clearing up any devices that were in service to prevent any consumer outages. KCP&L Smart Grid and Siemens were on-site to verify data was being sent correctly to and from the SICAM server. These groups all worked together to create any binary event, to execute any control, and to monitor all analog changes at substation relays. Point-to-point checkouts were conducted on every device that was deployed in Midtown Substation.

The field device point-to-point checkout was conducted by five groups: KCP&L Relay, KCP&L Linemen, KCP&L EMS, KCP&L Smart Grid, and Siemens. KCP&L's Relay group was on-site to create any binary status events, monitor any analog data, and provide feedback on any device controls. KCP&L EMS was responsible for clearing up any devices that were in service to prevent any consumer outages. KCP&L Smart Grid and Siemens were on-site to verify data was being sent correctly to and from the SICAM server. These groups all worked together to create any binary event, to execute any control, and to monitor all analog changes at substation relays. Point-to-point checkouts were conducted on several devices of each type, and the controls were tested on every recloser.

2.2.3.2.1.8 Adding Devices to SICAM

In the ideal scenario, all the substation and field devices for a DDC implementation would be known up front, and everything would be added once and then done. This is far from reality, though. For the most part, the substation devices are done once and finalized, but if another IEC61850 device needs to be added, this process is dependent on the device's CID file. The SICAM imports the CID file and then builds the device profile. Device signals will need to be mapped in the IEC61850 Client interface in order to be visible on the SICAM server, in the HMI interface to be visible on the HMI, and in the IEC61850 server to be visible on the DCADA and DMS.

Adding field devices to the SICAM is a much more common task, since field device deployments are rarely done all at once. DNP3 field devices in the SICAM are created through a user build process. This process starts by building a predefined template that will assign points to the SICAM through specific DNP addressing. Then the devices are added to the SICAM, and its communication and reporting parameters are defined. The predefined template is also selected during the device creation. Device signals will need to be mapped in the DNP Slave interface in order to be visible on the SICAM server and in the DNP Master to be visible on the DCADA and DMS.

2.2.3.2.1.9 Adding Points to Device Profiles

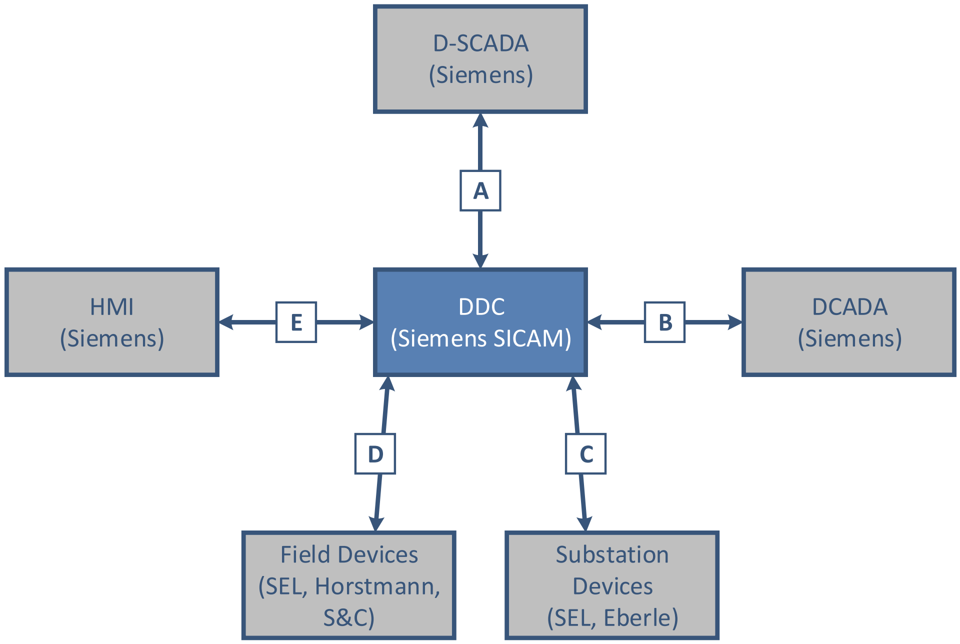
Adding additional points to a substation or field device profile is a bit tedious. Adding points to a substation device requires the creation of a new CID file that includes the additional point. The SICAM then updates the CID process on that specific device. The only further modification is to map the new points to any IEC61850 Client, IEC61850 Server, or HMI interface for visibility on the SICAM, DMS, DCADA, or HMI.

Adding field device points is a very involved process on the SICAM. This process requires building a new predefined template that adds the new point, while being careful not to eliminate any existing signals. The SICAM is incapable of having devices merely switch templates; rather, the addition of any new point requires the deletion of the device and reading of the device to implement the new profile. These points will need to be remapped on the DNP Slave and Master to guarantee visibility on the SICAM, DCADA, and DMS servers.

2.2.3.2.2 Integration

An overview of DDC system-to-system interfaces and applicable messages is illustrated in Figure 2-39.

Figure 2-39: KCP&L SmartGrid Demonstration Project DDC Integration



The integration touch points for the DDC are as follows:

A. DDC/D-SCADA Monitor and Control Propagation: A bi-directional interface allowing for substation and field device point monitoring details to be provided by the DDC to D-SCADA so that it has all updated information for use by the DMS. The interface also allows for any controls resulting from DMS functionality to be transmitted to DDC for further propagation to devices in the substation or the field. All data exchanges in this interface are transmitted via IEC 61850.

B. DDC/DCADA Monitor and Control Propagation: A bi-directional interface allowing for substation and field device point monitoring details to be provided by the DDC to DCADA so that it has all updated information for use by the substation controller. The interface also allows for any controls resulting from closed loop DCADA functionality to be transmitted to the DDC for further propagation to devices in the substation or the field. All data exchanges in this interface are transmitted via IEC 61850.

C. DDC/Substation Devices Monitor and Control Propagation: A bi-directional interface allowing for substation device point monitoring details to be provided by the substation device (bus main breakers, tie breakers, transformer differential relays, bus differential relays, feeder breakers, or load tap changers) to the DDC so that it has all updated substation information for use by the DDC and other upstream systems. This communication occurs in real time as device status changes, and it also occurs on regular intervals via predefined integrity polls initiated by the DDC. The interface also allows for any controls resulting from DDC functionality to be transmitted to the substation device. All data exchanges in this interface are transmitted via IEC 61850.

D. DDC/Field Devices Monitor and Control Propagation: A bi-directional interface allowing for field device point monitoring details to be provided by the field device (capacitor bank, fault current indicator, recloser, or battery) to the DDC so that it has all updated field device information for use by the DDC and other upstream systems. This communication occurs in real time as device status changes, and it also occurs on regular intervals via predefined integrity polls initiated by the DDC. The interface also allows for any controls resulting from DDC functionality to be transmitted to the field device. All data exchanges in this interface are transmitted via the Tropos network using DNP3.0.

E. DDC/HMI Monitor and Control Propagation: A bi-directional interface allowing for substation device point monitoring details to be provided by the DDC to the HMI so that it has all updated substation information for use by the HMI GUI. The interface also allows for any controls resulting from HMI functionality to be transmitted to the DDC for further propagation to devices in the substation. All data exchanges in this interface are transmitted via a proprietary Siemens protocol.

2.2.3.2.3 Post-Implementation Operational Issues

Following the initial implementation, testing and deployment of the DDC, numerous post-implementation operational issues arose that needed to be considered and mitigated. These issues included the following:

- Deadbands – One of the first issues that arose had to do with device deadbands. Rather than polling the substation and field devices periodically for updates, KCP&L wanted the devices to report by exception. Report by exception could potentially limit the amount of unnecessary data that flows into the SICAM, as data is only sent when an event occurs. For the binary and counter values, this is simple—the devices just report to the SICAM any time a status changes. For the analog values, however, the reporting frequency isn't as straight forward. The substation and field device analog values fluctuate in real time, but the SICAM doesn't need to be notified of every miniscule change. If every change was sent upstream, then the devices would be constantly transmitting updates. Instead, each device is configured with deadbands for all of the analog points. For the 61850 devices, when one analog reached a deadband, the device would send all the data points within that 61850 report. With KCP&L's initial deadbands, the devices were sending 61850 reports many times each second, and the SICAM processor became overloaded. After some analysis, the project team assigned new, wider deadbands to the analogs. For the substation devices, this required updated CID files, and for the field devices, this required updated settings files. These modifications worked well, and the frequency of transmitted updates to the SICAM became much more manageable.

  If KCP&L implemented 61850 in other substations at some point in the future, they would likely consider setting a deadband on only one type of analog in the 61850 report dataset. For example, they might set deadbands on all of the current values, so that only changes to the system current would trigger data transfer. Understanding 61850 reporting was critical to this realization.

- Point Limit –Another issue that the team ran into was a point limit on the SICAM. Originally, KCP&L planned to bring back a lot of data for the substation and field devices that wasn't necessarily needed by any of the DNA applications. The thought was that the devices were capable of sending all of this data, and that perhaps engineering would be able to utilize it for various purposes. The team didn't experience any issues after the substation devices were deployed, but as KCP&L and Siemens started to plot out the field device deployment, the team was informed that there is a 10,000 point limit to an individual SICAM. So the total number of binary, counter, and analog points for all of the substation and field devices needed to be less than 10,000. As a result of this hardware limitation, the team went back to the substation and field device profiles and reevaluated which data was still desired. The points list and templates were revised, and the "final" configuration with all the field devices was brought sufficiently below 10,000 points.

- Cascading Failures – In the original configuration, the SICAM had one "interface" to all the substation devices (the IEC 61850 interface) and one interface to all the field devices (the DNP3.0 interface). When the project team started to deploy the field devices, issues began to occur with the SICAM's DNP interface. After doing some monitoring, the team was able to pin down the specific problem. When the SICAM lost communications to a particular device (mostly due to the wireless network performance), it would continue to try to reestablish communications with that device. It would expend so much processing power on this single, problematic device, that it would lose communications with the other devices in that interface. As a result, the entire interface and the communications to all the field devices went down, including the devices that had good communication. In order to address this issue, Siemens directed the KCP&L team to change a few time out parameters to better accommodate the wireless communications to the field devices. Siemens also helped the team to split up the interfaces into smaller groups. The revised SICAM contained a number of interfaces, each with no more than seven devices. The devices were split into interfaces based on the feeders that they are associated with. This helped the issue a lot, and it also allowed the team to more easily determine which field devices had problematic communications.
- Hardware Limitations – Despite the deadband modifications and the reduction in total data points, KCP&L still had issues with the system hardware's ability to process all of the device data. As a result, Siemens upgraded the SICAM servers to enhance the processing power. Since this replacement, KCP&L hasn't had any issues with processing power limitations.
- Server Redundancy – The last major issue that the team experienced with the SICAM occurred when the SICAM was running in redundant mode. As described above, the long-term design configuration was to have two SICAMs up and running at all times so that if one piece of hardware failed, there would be a seamless transition to the other SICAM. Unfortunately, during periods of extended device outages, when communications with a single device are lost, the SICAMs begin to fail back and forth. Each SICAM is looking to the other one to bring up the connection to the problematic device, and they basically get stuck in the middle. During these times, the team is able to ping and telnet to the problematic device from either SICAM, but no connection is shown in SICAM. So the communications path is back up at this point, but the SICAMs have bounced back and forth enough that they get stuck in the process. When this occurs, the communications path to the problematic device needs to be stopped and restarted. The other approach that the team took to solve this problem was to focus on some of the problematic field devices and improve the communications to them via the wireless network. Focusing on the root of the problem eliminated the server redundancy issue.

2.2.3.2.4 Lessons Learned

Throughout the build and stabilization of the DDC (SICAM) system, numerous considerations were realized and should be noted for future deployments of this sort. These Lessons Learned are as follows:

- Non-Hardwired Interfaces - One of the major lessons learned on this project had to do with the interfaces to the field devices. Most data concentrators on the market today were designed for use in the substation, where there is a physical connection from the concentrator to each device. This is the case for the substation devices at Midtown, but the field devices utilize a wireless network to communicate to the SICAM. As a result, the project team experienced many issues with the SICAM to field device communications. Since wireless networks don't guarantee 100% uptime and availability, there are times when the SICAM polls the field devices and the communications fail. The way that the SICAM continues to poll that problematic device, and how this impacts the other, non-problematic devices, isn't conducive for field devices. Siemens and the project team spent a lot of time troubleshooting issues with the DNP3.0 interface, and they tweaked a lot of configurations in order to make the system perform sufficiently for the wireless network. For larger, system-wide deployments, using a traditional wired concentrator might not be feasible. In the future, vendors will likely need to design new concentrators that are built with wireless communications networks in mind.

- Conducting Logic at Concentrator - Another lesson that KCP&L learned from the SICAM implementation was that the substation data concentrator can be used in several different ways. Although the SICAM is capable of performing arithmetic functions, it wasn't configured as such for the KCP&L project. For the demonstration implementation, the SICAM was used solely as a concentrator. It received updates from the substation and field devices, and it sent the data upstream to the DMS, DCADA, and HMI. If KCP&L was to use the SICAM in the future, they would likely reconsider the implementation of this system. Since it is capable of performing calculations, KCP&L would probably limit the number of points reported back from each device. A smaller number of points would be sent to the SICAM, and then the SICAM could calculate the remaining points with that information. For example, instead of bringing back all the points associated with voltage, current, and power, the device would just send the voltage and current data and the SICAM would calculate the power values.
- CID File Management - KCP&L learned a lot about IEC 61850 and how to use it for substation communications. One lesson that was learned the hard way was that the CID files loaded on the device itself need to match the CID files loaded on the SICAM exactly. If they somehow get out of synch, connection to the device is lost, as seen by the SICAM. There were several instances where the relay technicians went out to the devices to do firmware updates, and the existing CID files were accidently dumped or replaced in the process. Determining a proper versioning method for the CID files would be critical for a multi-substation implementation.
- Manufacturer Specific IEC 61850 Implementations - The last lesson learned through the SICAM implementation had to do with manufacturer specific 61850 implementations. By design, the IEC 61850 standard is very flexible, and it was intended to meet many needs. While this can be a positive, it also leaves much room for interpretation, and vendors have interpreted the standard in different ways. Configuration tools for IEC 61850 are still in their infancy, and the industry has a long ways to go to fully configure a 61850 station. Currently a vendor-specific tool is the best way to do this configuration, since the vendors have interpreted the standard in such different ways. This can be problematic if the implementation uses multiple IED or system vendors, though. One example problem is due to 61850 being self-descriptive. This means that the device will tell you what points and services it offers. In theory, this is a great feature of 61850, but unfortunately the SICAM doesn't take advantage of this feature. Rather, it requires the 61850 configuration file from each IED be manually loaded into the master configuration. Another issue that the team encountered on the SGDP had to do with analogs. Specific firmware versions on SEL relays defined analogs differently – some were defined as full complex values, but others were defined as two values (an angle and a magnitude). SEL devices aren't consistent in the way they do this, and SICAM only supports one of these methods (angle and magnitude).

2.2.3.3 Human Machine Interface

The substation HMI provides a local view of all of the equipment located inside the fence of the substation. The purpose of the HMI is to give substation personnel a tool for viewing the current status of the equipment within the substation, as well as giving them the potential to operate the smart grid devices from within the substation control house. Unlike the DMS and the DCADA, the HMI does not contain any information about the field devices. The HMI does, however, provide information about the substation network equipment, which is not displayed in the DMS.

2.2.3.3.1 Build

The SICAM PAS HMI is one of Siemens commercially available utility products. By pursuing this “off-the-shelf” philosophy to the maximum degree possible, limited design and development efforts are required and the SGDP is provided the opportunity to evaluate the capabilities of existing products and technologies in meeting the emerging smart grid requirements. The following sections provide a summary of the development and configurations that were required to implement and deploy the desired HMI functionality.

2.2.3.3.1.1 Training

Work on the HMI began with some preliminary training. Training for the Siemens SICAM and HMI was conducted jointly in August, 2012. Participants learned about how to use the HMI, but didn’t learn much about initial GUI creation and configuration.

2.2.3.3.1.2 Initial HMI Configuration

KCP&L provided Siemens with the Midtown Substation one-line and network configuration diagrams, and Siemens began to create the Midtown HMI GUI. KCP&L also worked with Siemens to determine the event list and alarm list that they wanted to be used with the HMI. The alarm list for the HMI was created as a subset of the DMS alarm list (which was determined while creating the signal list).

Siemens showed KCP&L their initial version of the HMI, and the KCP&L team provided feedback based on the needs of the relay technicians. KCP&L also requested modifications to some of the data points displayed on the HMI GUI. Siemens made the modifications to the HMI and prepared it for the FAT

2.2.3.3.1.3 Factory Acceptance Test

The KCP&L team traveled to Minnesota for the HMI, SICAM, and DMS FAT from August 20 through August 31, 2012. During FAT, the team tested out the functionality of the HMI and the interface to the SICAM in Siemens’ Minnesota environment. As a reminder, the HMI only displays the substation devices – no field device information is shown in the HMI GUI. For the FAT, only one HMI was used, so the team wasn’t able to do any testing pertaining to redundancy.

Throughout the FAT, the KCP&L team tracked variances and prioritized them by severity. Upon completion of the FAT, they constructed a list of several modifications that they wanted to see prior to the Site Acceptance Test, in addition to several “enhancements” that might be added at a later date. Siemens made the necessary modifications and then sent the test HMI to Kansas City for deployment in the production environment.

2.2.3.3.1.4 Production Configuration and Site Acceptance Test

The production HMI configurations consist of the following:

- Two servers located in the Midtown battery control enclosure – these are to be used by the smart grid team
- One client located in the Midtown battery control enclosure – this is to be used by the smart grid team for demonstration purposes
- One client located in the Midtown Substation control house – this is to be used by the relay technicians

Like many other systems in the SGDP, the HMIs were configured to be redundant in the production environment. Unlike the other systems in the project, however, there are no HMIs in the development environment.

Upon configuration of all the HMI clients and servers in the production environment, SAT commenced. SAT for the HMI ran from September 17 through October 5, 2012 (though targeted test and variance remediation continued on sporadically for some time). For the HMI, SAT consisted of a point-to-point checkout of every substation device. It also included network testing, as well as checks of the event and alarm lists. The issues discovered during the point-to-point checkouts were all resolved immediately. The network issues were much more significant, however, as the HMI network GUI had been built from an outdated network diagram with old port mappings.

Before modifying the networking screen of the HMI, Siemens provided some HMI "retraining," this time focusing on how to create, configure, and alter screens in the GUI. Armed with this knowledge, KCP&L was able to resolve the port mapping issues and rebuild the network screen of the HMI. The network information now displayed on the HMI allows the user to verify whether any substation issues are related to network communications. Each substation device is connected to a particular network switch and mapped to a specific port. Although the user can't modify any network configurations from the HMI, he is able to easily determine whether any problems exist on the network prior to engaging the IT personnel at KCP&L.

2.2.3.3.1.5 Modifications per Ruggedcom Switch-Out

As described in Section 2.2.3.1.2, during the fall of 2013, KCP&L decided to replace the Ruggedcom switches in Midtown Substation with Cisco switches. Upon completion of this work, the HMI no longer painted an accurate picture of the Midtown Substation networking equipment. KCP&L worked with Siemens to modify the SNMP and completely update the port mapping for these new switches. Once this was done, the team conducted yet another port-to-port checkout to verify the updated mapping.

Screenshots of the current HMI GUI are shown below in Figure 2-40 through Figure 2-45.

Figure 2-40: HMI One-Line Screenshot

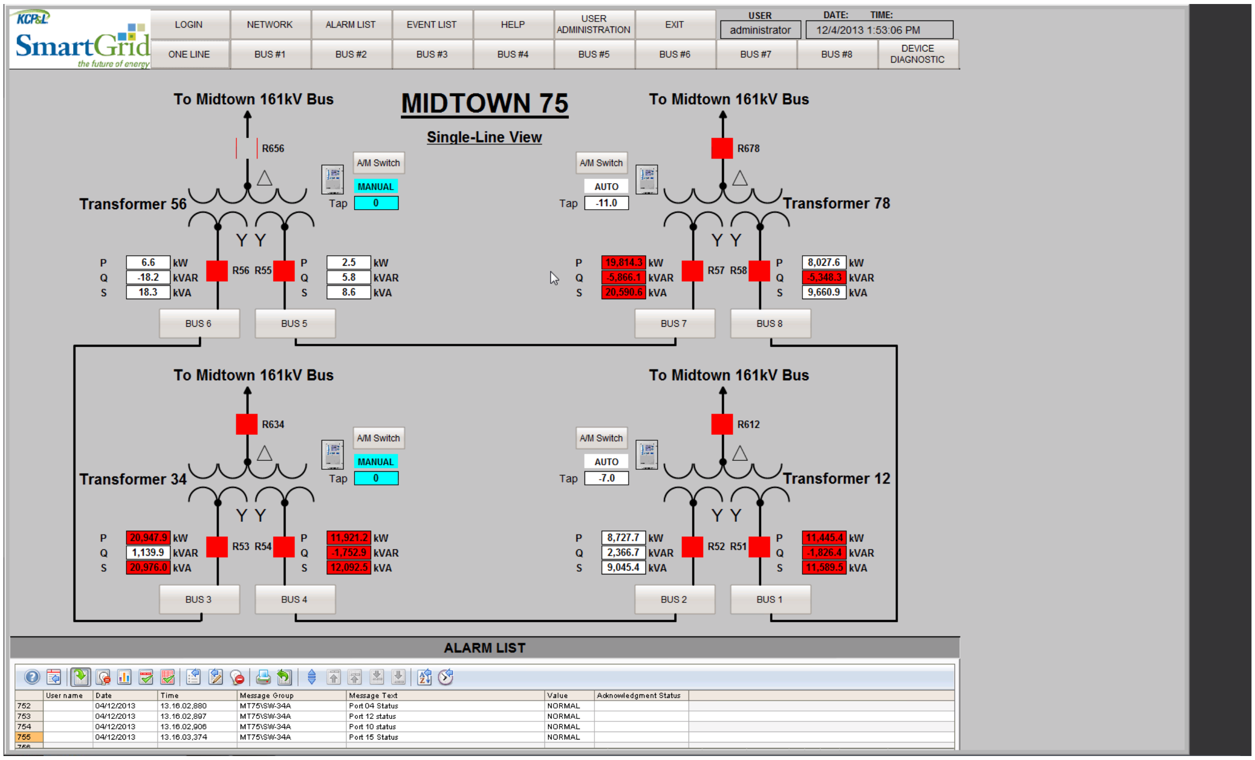


Figure 2-41: HMI Single Bus Screenshot

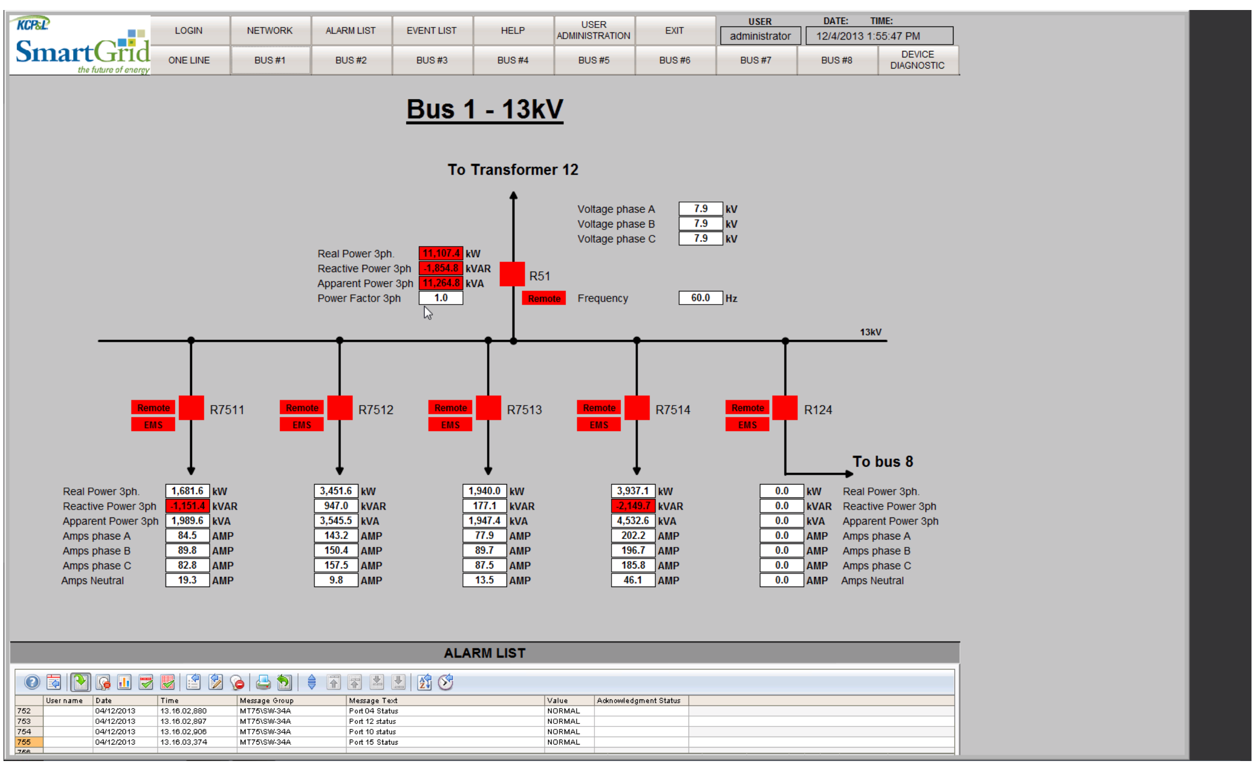


Figure 2-42: HMI Device Diagnostic Screenshot

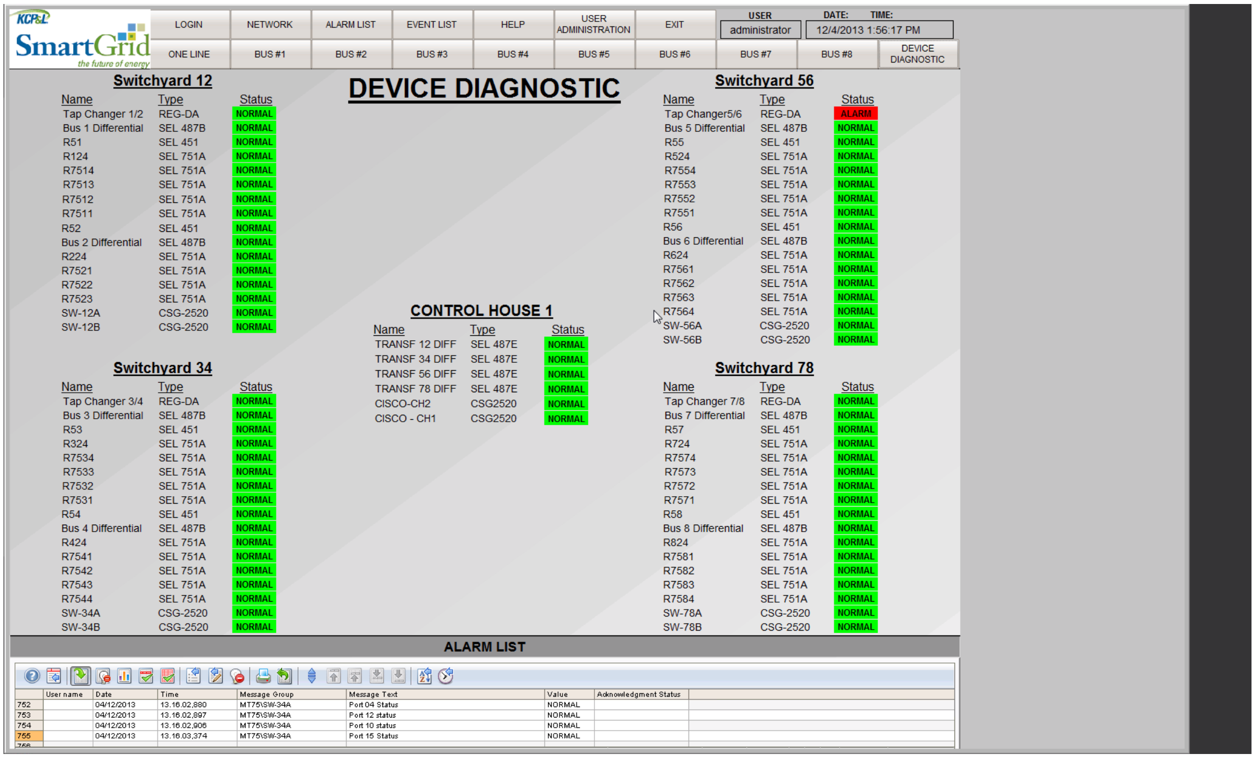


Figure 2-43: HMI Alarm List Screenshot

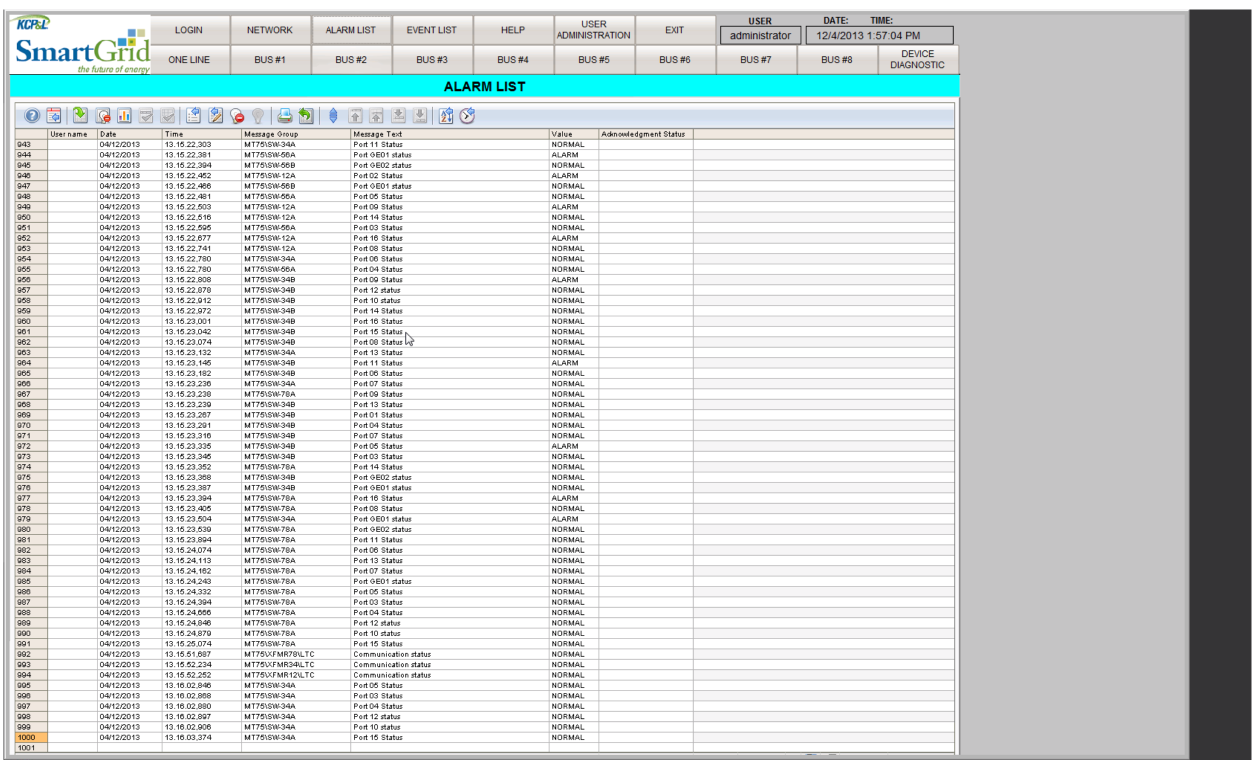


Figure 2-44: HMI Event Log Screenshot

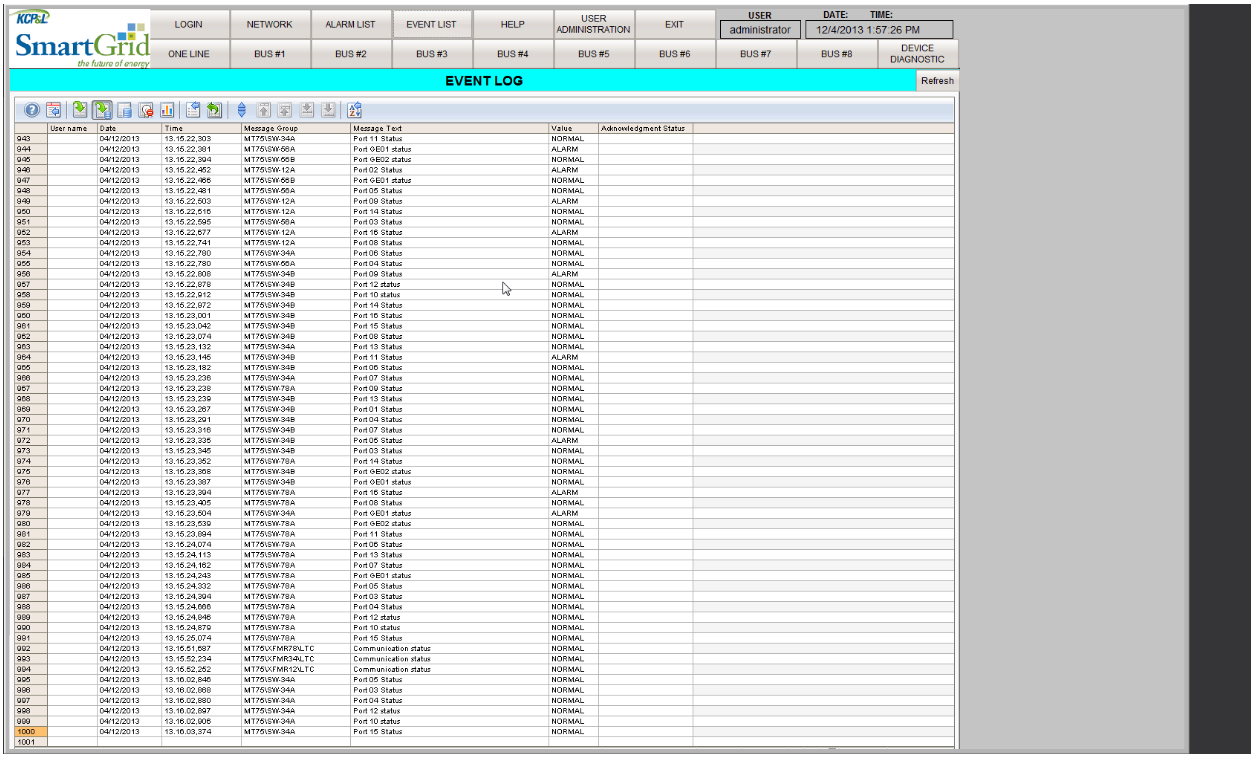
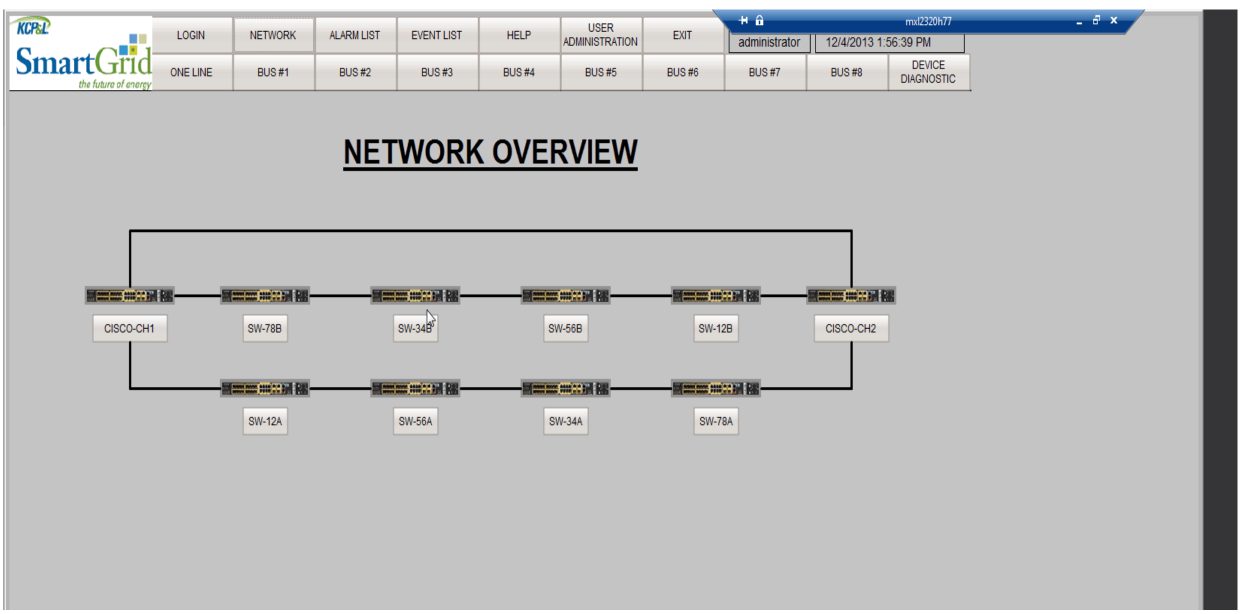


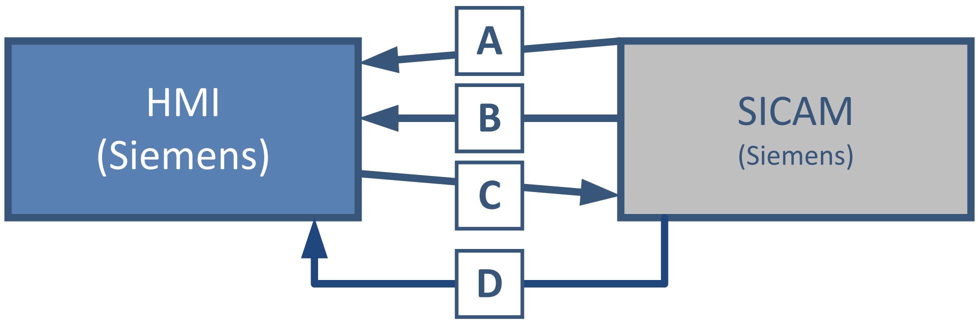
Figure 2-45: HMI Network Overview Screenshot



2.2.3.3.2 Integration

An overview of HMI system-to-system interfaces and applicable messages is illustrated in Figure 2-46.

Figure 2-46: KCP&L SmartGrid Demonstration Project HMI Integration



The integration touch points for the HMI are as follows:

A. 'Substation Device Status/Analog Update' notification initiated from substation devices to SICAM and sent from SICAM to HMI. (Reminder that field device data doesn't get passed to the SICAM – only substation device data.) This is an IEC 61850 status message used to notify SICAM (and HMI) of an updated analog or status at a substation device.
B. 'Substation Device Event/Alarm' notification initiated from substation devices to SICAM and sent from SICAM to HMI. (Reminder that field device data doesn't get passed to the SICAM – only substation device data.) This is an IEC 61850 event or alarm message used to notify SICAM (and HMI) of an event that has occurred or an alarm that has been activated.
C. 'Substation Device Control' message initiated from the HMI and sent to the SICAM and then on to the substation device. This is an IEC 61850 control message.
D. 'Network Device Status' message initiated from one of the substation network switches and sent to the SICAM and then on to the HMI. This is an SNMP message used to notify SICAM (and HMI) of the status of a particular network switch.

2.2.3.3.3 Post-Implementation Operational Issues

Following the initial testing and deployment of the HMI, several post-implementation operational issues needed to be considered and mitigated. Since devices are rarely added or removed from a substation, the HMI isn't likely to undergo many post-operational modifications. The post implementation issues experienced by the project included the following:

- Ruggedcom Switch Replacement – For KCP&L's implementation, the main post-operational HMI issue was the replacement of the Ruggedcom switches with Cisco switches. Since the network switches and their statuses are displayed on the HMI, the switch replacement forced the KCP&L team to re-work the network screens. Since the Cisco switches use different ports than the Ruggedcom switches, re-mapping wasn't a simple exercise. The switches each had to be failed over in order to generate and record the updated port mappings.
- Mapping and Display Modifications – In addition to the logical re-mapping described above, KCP&L also worked with Siemens to rework the graphical user interface of the HMI to accurately display the final as-built state of the Midtown Substation network.

2.2.3.3.4 Lessons Learned
Throughout the build, implementation, and daily operation of the HMI, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- GUI Creation and Modification - While minor changes such as GUI text modifications are simple on the HMI, creation and significant modification of the HMI display isn't very intuitive. It requires a comprehensive understanding of the GUI layers that wasn't easily attainable without advanced training.
- Event/Alarm Sorting - Sorting events and alarms on the HMI GUI can be a bit confusing. This topic generated discussion during training classes, and KCP&L made sure to train the end users specifically on this component of the GUI.
- Relay Tech HMI Benefits - The "finished" HMI was useful for both the smart grid project team as well as the system end user – the relay techs. By using the HMI at Midtown Substation, the techs will be able to see the status of all substation devices in one place, rather than walking around to each relay to troubleshoot or test. While this is obviously a convenience to the techs, it can also enhance the safety practices of this group.
- Network Visibility – The biggest unforeseen benefit of the HMI to the project was the visibility to the network statuses. Whenever the project team noticed a communications issue in the SICAM (where a device was running up), the first thing that was verified was the device status in the HMI. While some device communication issues were related to the specific substation device, other issues were tied to the network equipment. The HMI made it very easy to determine what action should be taken to resolve the issue.

2.2.3.4 GOOSE Messaging
For peer-to-peer communications in the substation, the IEDs utilized IEC 61850 Generic Object-Oriented Substation Event (GOOSE) messaging.

2.2.3.4.1 Build
The following discussion provides a summary of the development and configurations that were required to implement and deploy the desired GOOSE functionality.

2.2.3.4.1.1 Scheme Logic Design
The Midtown Substation GOOSE implementation began in 2010, when KCP&L started to think about what GOOSE schemes they wanted to implement. After several meetings, the KCP&L substation group decided on four schemes for the project:

- Automatic load transfer upon transformer lockout
- Faster clearing of the bus upon feeder breaker failure
- Backup overcurrent protection in the bus differential relay
- Cross triggering of all devices for distribution system event

After developing the initial logic for these schemes, the team loaded the logic onto the lab substation devices to ensure that they could support it. They wanted to ensure that the logic wouldn't overload the devices, as the devices are limited with how much logic they can process. Unfortunately, these limits aren't fixed values, so the only way to determine whether the devices can support the logic is to actually test it out.

2.2.3.4.1.2 CID File Creation and Initial Deployment

After doing some preliminary testing, the team made modifications as needed. Relay technicians then deployed the CID files to the substation devices, with the GOOSE schemes disabled. This allowed the team to begin testing out substation device communications with the SICAM via the IEC61850 MMS messaging, without having the GOOSE work fully tested and finalized.

2.2.3.4.1.3 Scheme Lab Testing and Modifications

In 2013, KCP&L came back to the GOOSE work and began in-depth testing. They started by reviewing the logic theoretically – looking at the logic flow diagrams and communications diagrams. Next, they went through the logic code for each scheme, line by line. They ensured that everyone was on the same page with each step of the logic scheme. Then, they tried breaking the code by using various inputs. They looked at each shed possibility, and they tested each one with different fail bits and trigger bits. Three of the schemes held up well to this logic testing, but the bus transfer scheme required several attempts.

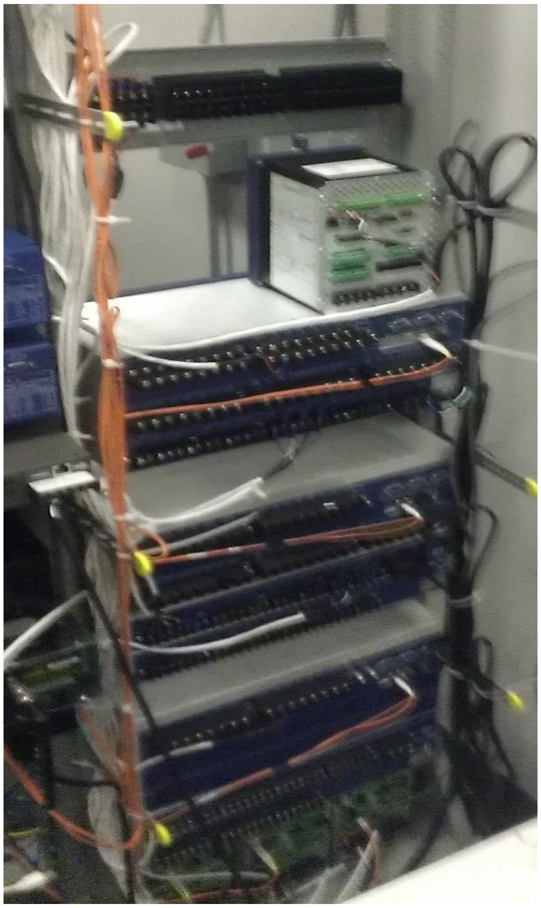
Next, the team mocked everything up in the Burns & McDonnell Smart Grid Lab. Their setup included the following:

- (6) SEL 751A feeder/tie breakers
- SEL 451-5 bus main breaker
- SEL 487E transformer differential
- SEL 487B bus differential
- SEL 3530 (RTAC) for automation control and to act as the far site
- Garrettcom Magnum 6k32f switch
- Computers to run SEL AcSELerator, SEL Architect, AX-S4, VM-Ware
- Manta test set for current and voltage inputs
- Test blades

Figure 2-47 below shows the test rack that was used for the 61850 GOOSE testing in the Burns & McDonnell Smart Grid Lab.

The testing team used test kits to provide the necessary voltage and current inputs, and they monitored the status of everything using 61850 on a temporary HMI. As they tested various scenarios, they made any necessary changes to complete the 61850 logic schemes.

Figure 2-47: GOOSE Lab Testing Rack Setup



2.2.3.4.1.4 GOOSE Activation and Production Testing

KCP&L took an incremental approach to GOOSE activation in order to gain comfort with the automation. Although this strategy required additional trips to the Midtown relays, it allowed for “safe” testing in the production environment. There are two settings pertaining to IEC61850 that are stored in the relay settings files. The “Enable IEC 61850 Protocol” setting in the relay settings file has been enabled since the substation devices were originally deployed at Midtown – this setting allows the substation relays to communicate to the SICAM using IEC61850 MMS messages. The second setting pertaining to IEC61850 is the “Enable IEC 61850 GOOSE” setting, and this was activated in January 2014.

After the January changes, one scheme was fully functional – the cross triggering of all devices for distribution system events. The event reporting scheme was triggered any time an “event” occurred, but since this scheme is simply reporting of statuses of all the substation devices, no devices opened or closed as a result. The other GOOSE schemes were put in monitor-only mode at this point. To do this, KCP&L took the settings that were already deployed in the relays, and they made modifications necessary to complete the GOOSE logic *except* for the trip and close equations. With these changes, when an event occurred, the relays did everything they were supposed to up until the point where a relay trip or close should occur.

While in monitor-only mode, a number of events occurred on Midtown feeders. For each event, KCP&L conducted a post-event analysis to determine whether the GOOSE logic would have resulted in the correct action. During monitor-mode operations, a number of issues arose – these are described in Section 2.2.3.4.3 below. None of the post-operational issues required any changes to the logic schemes, however.

After several months of monitor-only mode, the relay settings were updated again to put the devices in full operation mode for two additional schemes: 1) backup overcurrent protection in the bus differential relay, and 2) faster clearing of the bus upon feeder breaker failure schemes. To change to full operation mode, KCP&L took the trip and close equation and added in one more elements that is controlled by GOOSE logic. These changes were only deployed to the relays on buses 7 and 8. The automatic load transfer upon transformer lockout scheme was not put into full operation mode, as KCP&L determined that it would require significant outages to conduct a full-fledged test.

One fault has occurred on a bus 8 feeder since switching to full operation mode, but unfortunately the GOOSE logic did not operate due to some communications issues. KCP&L will continue to run buses 7 and 8 in full operation mode and do post-event analysis to verify that the GOOSE schemes function properly in the future.

2.2.3.4.2 Integration

For the GOOSE component of the demonstration, there isn't really any system-to-system integration, since GOOSE isn't a "system." Rather, GOOSE is a mechanism for transferring event data over entire substation networks. The GOOSE messages travel between the substation devices over the Midtown Substation protection network described in earlier sections (Overall SPN scope in Section 1.4.4.1 and SPN Implementation in Section 2.2.3.1).

2.2.3.4.3 Post-Implementation Operational Issues

Following the initial testing and production deployment of the GOOSE schemes, several post-implementation operational issues needed to be addressed. The post implementation issues experienced on this component of the project included the following:

- Protection and Control Network Communications – Since GOOSE was enabled in January 2014, there have been several issues with communications at the Midtown protection and control network. One of the Midtown events (a transformer outage) couldn't be analyzed because communication issues had filled up all of the logs. A feeder fault in October 2014 didn't function using the GOOSE logic because the communications didn't get from one device to another. As a result of these issues, KCP&L is working to ensure that the communications are as robust as possible so that the GOOSE schemes function properly.
- Time Synchronization – After analyzing the first set of Midtown events in the spring of 2014, KCP&L discovered that some of the substation devices were not storing the correct time. Some of these devices were off by one hour – this was resolved by addressing the DST settings. Other devices were offset by five hours – this was resolved by addressing an issue with the UTC offset. Finally, some devices were off by twenty minutes – after much investigation, this was resolved by changing a particular dipswitch in the SEL relays.
- Current Discrepancy – After some post-event analysis, KCP&L discovered that the buses were showing that they had a higher current than the feeders. KCP&L discussed this at length with the relay vendor, SEL, and concluded that this was a display discrepancy.
- Additional Device Elements – When the event cross triggering was initially deployed, KCP&L engineers were somewhat conservative in terms of the data elements that they wanted to record. There was so much potential information to record with the new relays, so the engineers had to be somewhat selective to stay within the bounds of the device capacity. Upon analysis of several events, however, they determined that they weren't close to the capacity limits, and they decided to add additional elements so that they could record more information.

2.2.3.4.4 Lessons Learned

Throughout the development and deployment of the GOOSE schemes, a few considerations were realized and should be noted for future deployments of this sort. These Lessons Learned are as follows:

- Deadbands - One of the lessons learned from GOOSE had to do with deadbands. While deadbands were addressed in-depth in the DDC section, they were also important for GOOSE messages. For the transfer scheme, the logic is sending analogs. The team had to double check all the multipliers and deadbands to ensure that the devices weren't sending GOOSE updates too frequently.
- Vendor Interoperability - Another lesson learned was in regards to vendor interoperability of the IEC61850 standard. KCP&L used all SEL relays, so this wasn't a big problem for the demonstration implementation, but it became obvious throughout the design/testing/build of the GOOSE component that things would have been much more complex had the project team utilized relays from multiple vendors. Taking advantage of the flexibility in the IEC 61850 standard, vendors have implemented the GOOSE protocol somewhat differently. For example, the standard specifies four identifying characteristics for each GOOSE message. Certain vendors will only use two of these characteristics for identification, while other vendors might use three characteristics, which may or may not overlap. Moving forward, utilities need to push the vendors to standardize on their GOOSE implementations.
- Deployment Timeline – KCP&L's deployment of the GOOSE schemes was slow and cautious. Any time a utility moves to a new technology, there will be resistance to change, especially if the current technology seems to be working smoothly.
- Cross Triggering Scheme Benefits – Although the cross triggering scheme doesn't result in any actions taken by substation relays, it has proven to be very beneficial for KCP&L engineers. They are able to see the status of all substation devices any time an event occurs in the substation, and this is very useful for post-event analysis.
- Logic Design for Communications Failures - Since KCP&L has experienced several issues with communications in the Midtown protection and control LAN, the engineers have given lots of thought to how communications issues impact the GOOSE schemes. For the faster clearing of the bus upon feeder breaker failure scheme, if communications fail and the devices operate based on their local protection settings, the result is no worse than the pre-GOOSE scheme. For the backup overcurrent protection of the bus differential relay scheme, however, if the communications fail, the result could be worse than the pre-GOOSE condition. If the feeder operates before the bus differential, then it isn't an issue. If the bus differential operates first and communications are down, however, then no reclosing will occur. Understanding the impact of communications failures on the outcome of various substation events with and without the GOOSE schemes is beneficial. If KCP&L re-designed the GOOSE schemes today, they would likely modify the logic so that if communications went down, the devices would just revert back to the old way of doing the scheme.

2.2.3.5 Substation DCADA

The Substation Distributed Control and Data Acquisition controller is the brains of the substation. It receives device status updates from the SICAM, and it determines how to respond to activity occurring on the distribution system.

The DCADA can perform many of the same applications as the Distribution Management System, but it does so in a closed loop method, and it can only control devices within its area of control. For the SGDP, the DMS and DCADA will be monitoring and controlling the same set of devices, since the Midtown Substation (and its associated substation and field devices) is the only substation that is part of the project.

2.2.3.5.1 Build

KCP&L's DCADA implementation efforts were launched by assembling a team of highly skilled individuals that would pursue and support the deployment of these advanced applications. To familiarize themselves with the goals of the project, the team began by reviewing previously created Use Cases to understand new processes and anticipated system functions. These Use Case documents were finalized where possible and provided to Siemens to establish their baseline understanding of what KCP&L hoped to achieve with the system implementation. Where clarifications were required, they were addressed during the Siemens Design/Configuration Workshops.

In parallel to KCP&L's preliminary use case familiarization efforts, Siemens began establishing its project team to perform the installation. The DCADA core capabilities and interfaces are part of a commercially available, productized software implementation which can be configured to the needs of a given customer. By pursuing this "off-the-shelf" philosophy to the maximum degree possible, limited custom design was required. However, the systems did require configuration to accommodate KCP&L's distribution system. In this context, Siemens began identifying key staff and subject matter experts who would be performing the configuration. As there were relatively few implementations of this product, staff began familiarizing themselves with the configuration elements required and documenting questions to be answered in preparation of the actual configuration efforts.

2.2.3.5.1.1 DCADA Testing

The DCADA system was the lowest priority system, as its functionality mirrors that of the DMS, but it runs in an environment with less opportunity for user control. As a result, KCP&L's overall strategy was to start by testing out the DNA applications in the open loop mode at the DMS, then move to closed loop testing at the DMS, and then finally conduct closed loop testing at the DCADA.

The DCADA implementation was part of KCP&L's Phase 3 DMS work. This phase of implementation and testing focused on the First Responder (or DNA) applications. The goals of this phase were to progressively validate and stabilize DNA results based on required D-SCADA inputs.

The KCP&L team performed DNA and DCADA FAT from KCP&L's facilities and accessed the Minnesota based systems for testing from February 4 through February 15, 2013. During FAT, the team tested out the functionality of the DCADA and the interface to the SICAM and DMS in Siemens' Minnesota environment.

Throughout the FAT, the KCP&L team tracked variances and prioritized them by severity. Upon completion of the FAT, they constructed a list of several modifications that they wanted to see prior to the Site Acceptance Test (SAT), in addition to several "enhancements" that might be added at a later date. Siemens made the necessary modifications and then sent the DCADA to Kansas City for deployment in the production environment.

Once the DCADA servers were deployed in the KCP&L lab and demonstration environments, the Site Acceptance Testing began. The first pass of DCADA SAT testing occurred between 10/10/2013 and 10/22/2013. It included tests covering all of the First Responder applications: State Estimation, Power Flow, Volt-VAR Control, Feeder Load Transfer, Fault Location, and Fault Isolation and Service Restoration. All of this testing was done on the lab DCADA instance. To learn more about the First Responder applications above, refer to the pertinent scope section (specifically 1.4.5.4).

2.2.3.5.1.2 Closed Loop Operation

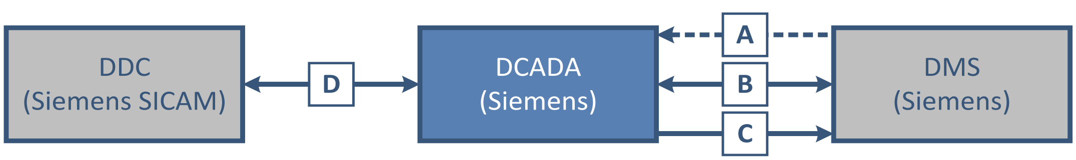
Although the DCADA received substation and field data updates from the SICAM, it was not used extensively as the control engine for closed loop applications. KCP&L gained confidence in the systems using a "crawl, walk, run" philosophy: first, they tested the applications from the DMS in an open loop format, then they tested applications from the DMS in a closed loop format, and finally, they tested applications from the DCADA. Although the DCADA shouldn't really have open loop capabilities by design, KCP&L was able to operate it in this manner to gain comfort with the system. In order to test the DCADA safely in the production environment, the device controls were blocked for most testing. With this setup, almost all of the DMS testing was feasible at the DCADA level, with the exception of the failover tests. Running the tests in this manner allowed KCP&L to ensure that the DNA applications provided consistent results from both the DMS and the DCADA, but it kept the DCADA from actually controlling the devices.

Although KCP&L wasn't comfortable controlling breakers based on DCADA's FISR and FLOC results, they were comfortable controlling capacitor banks. As a result, the project team was able to run VVC from the DCADA and allow the application to dictate actions for the capacitor banks.

2.2.3.5.2 Integration

An overview of DCADA system-to-system interfaces and applicable messages is illustrated in Figure 2-48.

Figure 2-48: KCP&L SmartGrid Demonstration Project DCADA Integration



The integration touch points for the DCADA are as follows:

A. DMS/DCADA Model Synchronization: A uni-directional interface allowing for data model updates to be propagated from the DMS to the DCADA as required to stay synchronized as changes are activated from IMM. All data exchanges in this interface are transmitted via proprietary protocols.
B. DCADA/DMS SCADA Data and Mastership Synchronization: A bi-directional interface allowing for the following data to be provided by the DMS to the DCADA (if the DMS is in control), or from the DCADA to the DMS (if the DCADA is in control).
   - Tags (markers)
   - Jumpers, cuts, and grounds
   - Control actions

   This interface also allows for the transmission of delegated control permissions to be exchanged between DMS and DCADA to ensure synchronization of SCADA mastership. All data exchanges in this interface are transmitted via propriety protocols.

C. DCADA/DMS Alarms: A uni-directional interface allowing for the transfer of SCADA and application alarms from the DCADA to the DMS (if the DCADA is active in closed loop). Example conditions that would generate alarms include:
   - DCADA application failed to reach a solution
   - Control was transferred from DCADA to DMS
   - Link between DMS and DCADA is broken
   - An applications running at the DCADA doesn't converge or finishes with violations
   - First Responder application running at the DCADA can't complete operations due to device control being disabled

   All data exchanges in this interface are transmitted via propriety protocols.

D. DCADA/DDC Monitor and Control for Field Values: A bi-directional interface allowing for DCADA point monitoring details to be provided by the DDC (SICAM) so that it has all updated information for propagation to other systems. The interface also allows for any controls resulting from upstream closed-loop DNA applications to be transmitted to the DDC (SICAM) for further propagation to devices in the field. All data exchanges in this interface are automatically transmitted via 61850 protocols.

2.2.3.5.3 Post-Implementation Operational Issues

KCP&L didn't use the DCADA extensively; instead, most of the operations were done at the DMS level. As a result, there weren't many opportunities for operational issues with the DCADA. The main post-implementation issue experienced by the project was the following:

- Change Management – The DCADA was designed to operate in closed loop in the substation without any user intervention. The user has the authority to enable and disable DCADA closed loop at the substation, but he does not have the flexibility to authorize individual decisions made by DCADA. This proved to be a major change management issue as the operations group was very uncomfortable in relinquishing complete control from the onset. Though incongruent with the DCADA philosophy, additional flexibility in terms of user intervention at least during the implementation or testing phases would help gain the trust of the operations group and transition into full-fledged closed loop mode. This was a major stumbling block and DCADA was run minimally in open loop mode which was similar to the DMS and did not serve the intended autonomous capacity of the DCADA.

2.2.3.5.4 Lessons Learned

Throughout the build, implementation, and operation of the DCADA, one main consideration was realized and should be noted for future implementations. This Lesson Learned is as follows:

- Hierarchical Control – The DCADA and its closed loop functionalities are designed to be enabled all at once without any granularity. When an operator assigns control to DCADA or enables closed loop, all DCADA applications are enabled in closed loop. The operator does not have the option to selectively enable closed loop on DCADA and DMS applications. Additionally the operator does not have the option to limit the area of responsibility of the application in terms of feeder, bus etc. There is no way to run certain network segments (for example, a particular feeder) in closed loop. Rather, if one feeder is running an application in closed loop mode, then all feeders on that transformer need to be running that function in closed loop mode. The operator should have the option of running an application selectively in DMS or DCADA and also limit the area of responsibility of an application.

2.2.4 SmartDistribution

The SmartDistribution subproject deployed a state-of-the art DMS with integrated UI/CAD, OMS, D-SCADA, DNA First Responder applications, and Historian components to manage numerous field devices and sensors across a wireless mesh IP network. KCP&L selected the Siemens-Intergraph DMS as it was a pre-integrated, commercially available DMS solution. By pursuing this "off-the-shelf" philosophy to the maximum degree possible, limited design and development efforts were required and the SGDP is provided the opportunity to evaluate the capabilities of existing products and technologies in meeting the emerging smart grid requirements The following subsections summarize the SmartDistribution component deployments.

As the project progressed and KCP&L further assimilated the scope and complexity of this overall project, questions arose regarding the feasibility of the original intent to conduct one comprehensive configuration and test effort for DMS functions. An analysis was performed to better understand the critical interdependencies between systems to ensure successful testing and deployment. The result of this analysis showed that complexity in the related systems would benefit from increased focus on narrower definitions of scope. The D-SCADA capabilities are a critical pre-requisite for CAD, First Responder, and DERM functions. Without stability of D-SCADA and downstream device communications, no data points would be transmitted allowing these functions to perform. As a result, the KCP&L team decided to break the configuration and deployment of the overall DMS into three phases; D-SCADA capabilities were broken into two logical components and scheduled first to provide maximum stability for later First Responder efforts. Each of the phases of work would include vendor configuration, FAT), and then conclude with KCP&L installation and SAT.

- Phase 1 – Substation Device Monitoring: All substation devices to be automated through the project (breakers, differentials, tap changers, etc.) were configured and installed at KCP&L's Midtown Substation. In parallel, preliminary efforts were conducted to deploy the D-SCADA system to all environments and establish preliminary communications for remote monitoring of substation device point changes. Point-to-point monitoring-only checkouts were conducted on all points for all substation devices to ensure proper communications from the device through to the CAD.
- Phase 2 – Substation Device Control & Field Device Monitoring/Control: All field devices to be automated through the project (reclosers, fault indicators, capacitor banks, 1-MWh battery) were configured and installed along selected highly automated circuits. With all devices fully installed and D-SCADA further stabilized, communications for field device monitoring were established and control capability enablement for all devices (both substation and field) were planned, tested, and activated. Point-to-point monitor and control checkouts were conducted on all points for all substation and field devices to ensure proper communications to/from the devices through to the CAD.
- Phase 3 – First Responder Applications: Finally, the team enabled the configured DNA applications. They progressively validated and stabilized results based on required D-SCADA inputs. They commenced efforts with State Estimation and Power Flow; advanced to Volt-VAR Control, Feeder Load Transfer, Fault Location, Fault Isolation and Service Restoration. Once confidence in the above capabilities was established and the applications configured to maximum performance and user comfort in CAD, efforts could continue to advance on closed loop functionality and validation of these capabilities when delegated to the DCADA authority through the Control UI functionality in the CAD. Outage Restoration and Power Status Verification efforts and DERM integrations was also pursued during this final phase.

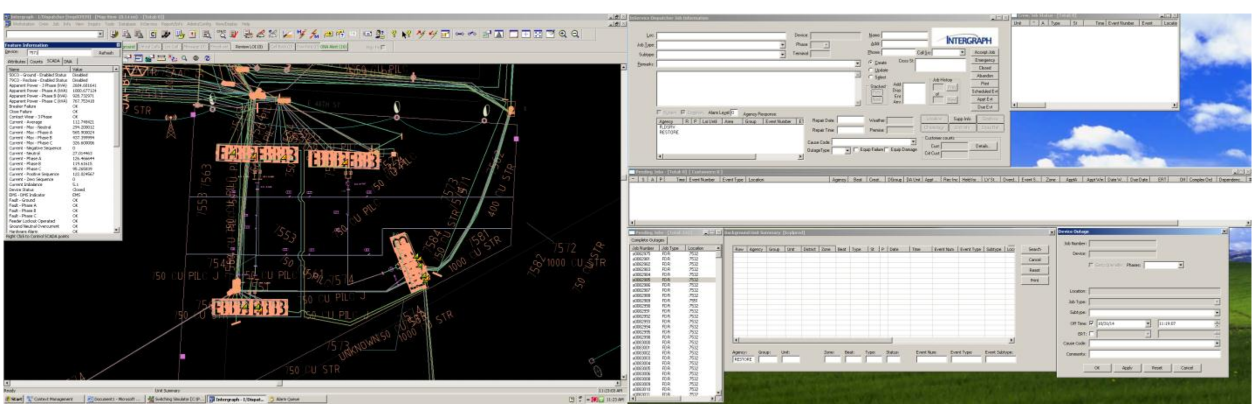
Another key takeaway from the initial implementation analysis was the need to establish and maintain several integrated environments to ensure that functionality was safely segregated for forthcoming development and testing efforts. Due to the complexity of integrating systems within each of these environments, the effort to set these up was commenced early to ensure their readiness as needed.

- Vendor Environment: The first and most basic environment was the vendor environment. The UI/CAD, OMS, D-SCADA, DNA, DCADA, and SICAM DDC applications were installed on KCP&L owned servers that were sent to the Siemens facility for initial configuration. In addition, sample substation controllers were also provided for vendor use. All hardware was extensively used to establish initial configurations and ensure they were working under controlled conditions.
- Lab Environment: The second and more complex environment was the lab environment. It was initially setup to augment the vendor environment, as sample field devices were setup and connected to a lab dedicated network which was interfaced with the servers of the vendor environment for preliminary tests. Later in the project lifecycle, the sample substation devices were transferred back to KCP&L's facility and additional KCP&L procured servers were then setup in the lab to establish a stand-alone environment; the connection to the vendor environment was severed. By that point, the lab also had integration with numerous other systems to more robustly mimic demo and was used to test out preliminary integration configurations.
- Demo Environment: The final and most complex environment was the demo environment. This was KCP&L's real-world environment where the systems were supported by redundant servers, configured for full integration with other systems, and connected to all of KCP&L's smart grid devices deployed to the substation and certain highly automated distribution feeders. As these devices would result in real-time, real-world distribution network changes, special care was taken to ensure that no negative consequences resulted from the team's efforts when testing in the demo environment

2.2.4.1 DMS UI/CAD

The Intergraph DMS UI/CAD component establishes a platform by which the Distribution Grid Operators can access all important information relating to customer and network operations from a single user interface illustrated in Figure 2-49. The following sections provide a summary of the development and configurations that were required to implement and deploy the desired DMS UI/CAD functionality.

Figure 2-49: KCP&L SmartGrid DMS Consolidated User Interface



2.2.4.1.1 Build

KCP&L's Integrated UI, also known as Computer Aided Dispatch (CAD) or more specifically Intergraph's InService (I/Dispatcher module), implementation efforts were launched by assembling a team of highly skilled individuals that would pursue and support the deployment of these advanced systems. The goal was to upgrade and integrate the primary control room systems so that Distribution Operations users could access all important information relating to customer and network operations from a single user interface. To familiarize themselves with the goals of the project, the team began by reviewing previously created Use Cases to understand new processes and anticipated system functions. These Use Case documents were finalized where possible and provided to Intergraph to establish their baseline understanding of what KCP&L hoped to achieve with the system implementation. The use cases served as a solid foundation of understanding for newer team members. Where clarifications were required, they were addressed during the Design/Configuration Workshops.

In parallel to KCP&L's preliminary use case familiarization efforts, Intergraph began establishing its project team to perform the installation. The I/Dispatcher core capabilities and interfaces are part of a commercially available, productized software implementation which can be configured to the needs of a given customer. By pursuing this "off-the-shelf" philosophy to the maximum degree possible, limited custom design was required. However, the systems did require configuration to accommodate KCP&L's distribution system. With this in mind, Intergraph created a System Configuration Diagram based on discussions with KCP&L to better understand the system configuration and requirements. Intergraph then developed a detailed plan which outlined the time required to meet these requirements and configure the system per KCP&L's needs. As there were relatively few implementations of this integrated DMS solution, staff began familiarizing themselves with the key configuration elements required and documenting questions to be answered in preparation of the actual configuration efforts.

2.2.4.1.1.1 Collaborative Design Sessions

After the preliminary familiarization efforts conducted by KCP&L and Intergraph, several workshops were conducted to expedite the configuration effort. The First Responder and Facility Migration Design workshop was conducted to review the details of First Responder data required and KCP&L's existing mapping technologies. The DMS InService Integration Design workshop (focused on D-SCADA integration) was held in which Siemens, Intergraph, and KCP&L jointly participated in this workshop to ensure that all parties were in agreement about the design and configurations to be pursued. Specifically, analysis was performed on the CAD and how it would work with Siemens' D-SCADA (PowerCC) via productized integration. A key element of the workshop was a detailed matrix outlining the data points required from each device to support proper algorithmic processing in the First Responder (DNA) applications; this formed the basis for follow-on signal list definition efforts. To this end, a foundational understanding of the overall model build process was also established. All parties were keenly aware that the signal list definition was central to forward project momentum and that numerous iterations of a model build would be required for stability and full device inclusion through the integrated D-SCADA. At the close of the workshop, KCP&L had a better understanding of what additional data requirements needed to be compiled and provided as it became available. Siemens and Intergraph left with a better defined set of requirements that they could use to begin their efforts.

During the InService Integration workshop there were also several discussions regarding the AMI, CIS, and how both integrate with the OMS and CAD. There were additional discussions on accessing data from the CIS in a format as required by Intergraph and the usage of MQ interface for AMI and MDM communications. KCP&L and Intergraph had substantial discussion on alarming and the required applications that would generate alarms on the Integrated UI from the native InService systems and the various other systems that would be integrated with the CAD. The DNA applications that were to be incorporated into the UI and their data requirements were also discussed and determined. Finally, all involved parties worked on technical specifications to ensure coordinated development of the interfaces to develop the standards-based messages that would be used to exchange the agreed upon information.

KCP&L concluded the workshop series with the recognition that a detailed signal list was required to configure specific points applicable to specific devices. KCP&L started by detailing those points required by Siemens for the First Responder applications to run. However, KCP&L found there to be many additional data points that could be brought back from each of the devices to the data concentrator. These additional points and resulting analytic possibilities were determined to possibly increase situational awareness for operators and were considered for display to the user. KCP&L conducted numerous discussions to establish internal agreement on the set of points that might be useful for operational activities outside of the DNA applications and provided these finalized signal lists to Intergraph and Siemens for their configuration efforts.

2.2.4.1.1.2 System and Interface Configuration

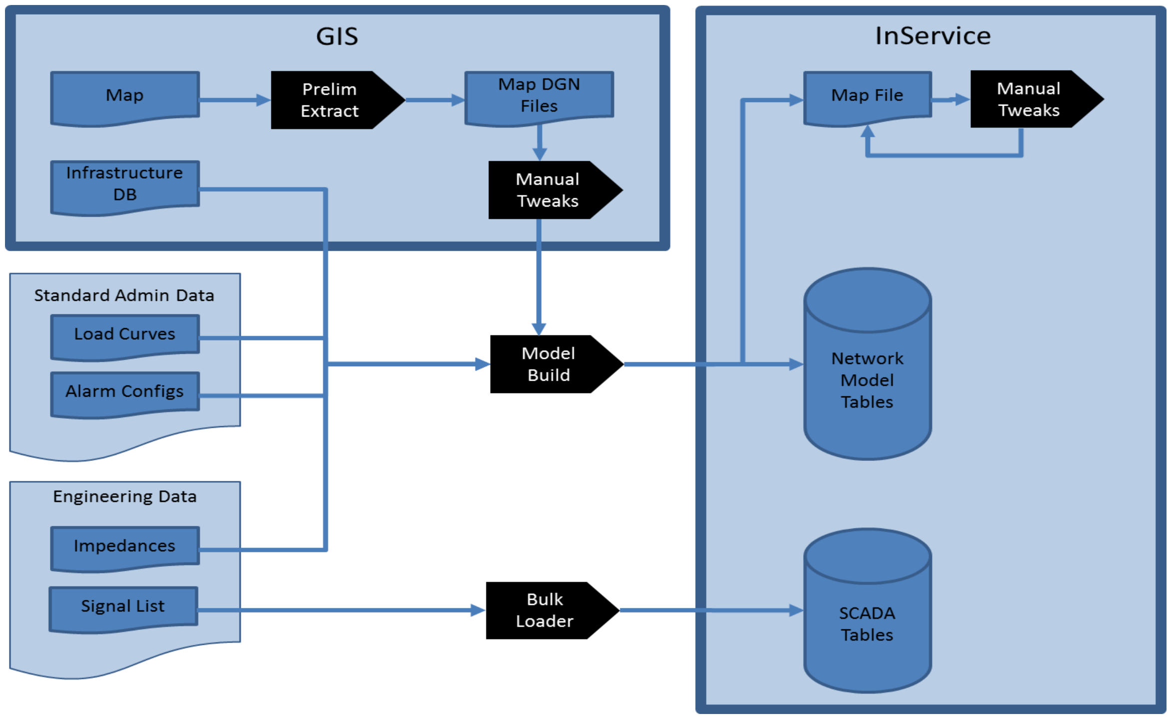
After establishing requirements, configuration considerations, environmental parameters, and a schedule fully recognizes and accommodates dependencies, then development and configuration efforts could begin in earnest. Both Phases 1 and 2 followed the same configuration approach. Intergraph consolidated all configuration data provided along with all requirements and began working independently in the vendor environment. Numerous iterations of configuration and isolated testing were performed to establish preliminary functionality. As conditions warranted, Intergraph coordinated joint working sessions with Siemens to work through integration efforts with the D-SCADA system (also co-located in the vendor environment). For Phase 3 scope, additional working sessions were conducted with another Siemens team responsible for the First Responder capabilities to ensure proprietary integration with that system was working as expected. Later, as the preliminary configurations were coming together, KCP&L facilitated daily working sessions between KCP&L, Siemens, and Intergraph to ensure a comprehensive and synchronized understanding of the deployment in some of its most nuanced ways. Shared-desktop technology (WebEx) was used extensively to enable these conversations between remote participants by allowing everyone to see the same system function, defect, or configuration process.

2.2.4.1.1.3 Data Model Migration

While numerous configuration efforts were vital pre-requisites to create a DMS data model that the DMS components could use for all of its algorithms, a particularly laborious component was the DMS UI/CAD (InService I/Dispatcher) model build process illustrated in Figure 2-50. During the design sessions, the project team determined that the existing GIS network model extract used for the InService Mobile Workforce Management System (MWFM) could be leveraged with several minor changes for creating the InService I/Dispatcher network model. Initial model migration efforts were performed in the vendor environment and numerous iterations were conducted. These iterations served the dual purpose of ensuring a quality automation process (in anticipation of numerous data model migrations supporting ongoing device deployment) as well as overall data quality (to validate properly synchronized between devices allowing for end-to-end communications). The KCP&L project team worked diligently with Siemens and Intergraph to understand the data model propagation as well as the behind-the-scenes implications of various configurations. The InService I/Dispatcher model build process is explained in detail in the following paragraphs.

The GIS is the original source of the network model utilized by the DMS and it must be kept up to date so as to predict the outages accurately and perform accurate network analytical computations. The first component of the data migration is the extract of data from the GIS. The map is preliminarily extracted from GIS in which the data elements are standardized for migration. The extracted distribution system map from GIS is saved as a DGN file. The DGN file is then manually reviewed and, if needed, required tweaks in the map can be applied. Since, the SGDP area is limited to the Green Impact Zone the map is tweaked and edited as per the requirements and geographical area. This edited and updated map is now ready as an input to be augmented through the Network Model creation process.

Figure 2-50: InService I/Dispatcher Model Build Process



The second component of the data migration augments the preliminary network model map with additional required information from GIS and data such as, load curves, line impedances and alarm configurations. The load curves and alarm configurations are the standard Admin data and, through numerous iterations, were tuned and finalized to use with the network model. In particular, the load curve illustrates the demand or load over a period of time and is used by the DNA First Responder functions and load modelling. The alarms for various field devices (e.g. capacitor banks, reclosers, breakers, etc.) were configured for different data points to help the operator to see the outages, issues with devices, etc. Impedance of the distribution circuits is also an important factor for load flow analysis. The infrastructure database is a supplementary source of asset data which is also stored in the GIS. All these data elements, along with the map DGN file, are used by the model build process to develop the final InService I/Dispatcher Network Model Tables. The Network Model Tables consist of all the information in InService I/Dispatcher that allow operators to conduct load flow analysis, capture/display outages in real time on the map, and maintain full synchronization between the systems and the real world devices.

The final component of the data migration process populates the SCADA tables with all pertinent details of the SCADA signal list. The SCADA signal list is the list of all the data points for different types of devices along with the DNP points, ICCP names, alarms, device type, point name, etc. The signal list is compiled before-hand from all the available devices in the distribution system. It is fed to the bulk loader to upload the information to SCADA tables in InService I/Dispatcher. The SCADA table then contains all the information needed to support synchronized communications between SICAM and DMS/PowerCC including: ICCP names, DNP points, data points, alarms, etc.

2.2.4.1.1.4 Training

The KCP&L team learned a tremendous amount during the workshops and joint configuration sessions. However, formalized training was still deemed very important to allow KCP&L users to prepare for formalized testing efforts and ultimately successful operation of the system. Sessions were conducted in-person and numerous training manuals were available to aid the process. In addition, given the previously established successes with WebEx, KCP&L leveraged this technology in a two-fold manner: 1) many training sessions were broadcast via WebEx which allowed targeted vendor subject matter experts to augment materials presented by the official trainer and 2) training was recorded allowing for ease of referencing back to better understand an explanation or sequence of events. The following table outlines training sessions conducted for Consolidated UI functionality.

Training Course	Dates
I/Dispatcher Training (Intergraph)	07/31/2012 through 08/02/2012
Tester Training (Intergraph and Siemens)	08/13/2012 through 08/14/2012
Alarm Configuration (Intergraph)	10/8/2012
Switch Planning (Intergraph)	10/9/2012 through 10/10/2012

2.2.4.1.1.5 Testing

As outlined above, the more advanced training sessions provided an opportunity for in-depth reviews of functionality to learn how the system is operated. In addition, due to the significantly advanced configuration by this time, the training sessions in the vendor environment also provided an opportunity for KCP&L's testing team to select a subset of tests from the formalized test books and review their workability during the training sessions. Additionally, Siemens and Intergraph performed an extensive "Pre-FAT" test where they internally verified that all functionality listed in the test books were working as expected. Formal testing efforts commenced with the Phase 1 Factory Acceptance Testing where KCP&L staff travelled to Siemens facility and watched a demonstration of the CAD capabilities along with the D-SCADA with the timestamp generated from a device going through the DDC, D-SCADA and displayed on the CAD. The highest criticality defects were immediately rectified and the servers were sent to KCP&L for installation to the Midtown Substation (demo environment). The system was stabilized and a robust SAT was performed to ensure that the systems were able to properly transmit device monitoring signals between servers.

Later, as configuration progressed, Phase 2 FAT was performed but deviated slightly as required by the defined scope. Specifically, substation devices remained at the Siemens facility and this time testing ensured appropriate monitor and control capabilities. Field devices were tested differently, as the devices remained in KCP&L facilities (lab environment). The field devices were connected to a WAN and then they communicated with SICAM, D-SCADA, and CAD in the Siemens facility. This testing required some portion of the test team to remain at KCP&L to verify synchronization with the test efforts being conducted at Siemens. Again, the highest criticality defects were immediately rectified and additional servers were then sent to KCP&L for installation to the Midtown Substation (demo environment). The system was again stabilized and a robust SAT was performed to ensure that the systems were able to properly transmit monitoring and control signals to/from substation and field devices. Throughout the FAT and SAT for both phases, where needed, defects were documented and logged with a tag corresponding to the appropriate testing effort.

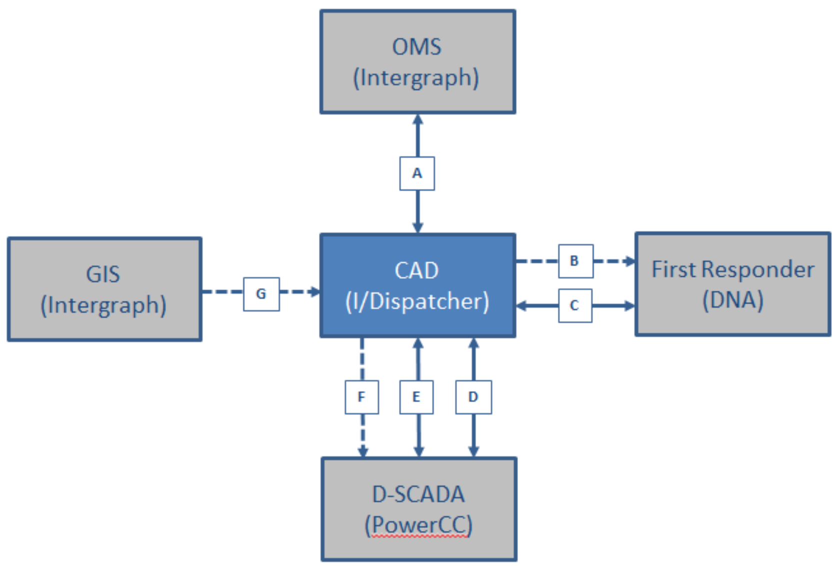
Finally, during Phase 3, the display capabilities of the Consolidated UI were pushed to new territories with the added functionality of displaying algorithmic results from Siemens DNA. Using new screens and new interfaces, a pre-FAT testing effort was again pursued, but this time as a joint weekly session between Siemens, Intergraph, and KCP&L to review the capabilities. Each week a different advanced application was reviewed which allowed all teams properly focus on the nuances of the particular capability. Having resolved many initial defects, FAT was conducted in the vendor environment and went rather smoothly based on the time invested during pre-FAT. At that point, all configurations were migrated to the demo environment where the comprehensive and fully integrated system could be tested as part of SAT.

All testing efforts resulted in numerous defects being documented where functionality deviated from established requirements. Intergraph worked to remediate these defects as soon as they were discovered and continued working to remediate throughout 2013; as variances were fixed, new service packs would be compiled on a regular schedule and installed to KCP&L's lab and demo environments for re-testing.

2.2.4.1.2 Integration

An overview of UI/CAD system-to-system interfaces and applicable messages is illustrated in Figure 2-51.

Figure 2-51: KCP&L SmartGrid Demonstration Project CAD Integration



The CAD (I/Dispatcher) is the core point of convergence in the DMS where pertinent data is aggregated and displayed to the end-user to take action. This special integrated UI is the command and control center with a common user environment. It consolidates multiple control room systems into one user interface to improve situational awareness and reduce human error. The Integrated UI will provide comprehensive dialog for SCADA Alarms, Crew Status, Pending Jobs, and Work Dispatched. The UI analyzes and displays data to the user as applicable from the various other component systems of the DMS which are integrated with it. The integration touch points for UI are as follows:

A. OMS/CAD Proprietary Integration: A bi-directional interface that allows outage information, crew data, new/pending jobs, and outage aggregations/predictions to be sent from the OMS to the CAD for the user to view and take appropriate action. This interface also allows the user to access meter data from the MDM, send meter pings, and receive power status verification messages from the meter through the OMS. All data exchanges are automatically transmitted through Intergraph's proprietary technology.

B. DNA/CAD Data Model Propagation: As part of the overall network and data model propagation process from GIS to the DMS suite of systems to have an updated data model across all systems, the key details of the network model are prepared in CAD and then transferred to DNA. This process is performed on an ad-hoc and largely manual basis.

C. DNA/CAD UI Integration: A bi-directional interface allowing for DNA algorithmic results and recommendations to be forwarded on for display to the user. The interface also allows user selections and configurations to be passed from the CAD User Interface to DNA. All data exchanges in this interface are via MQ.
D. D-SCADA/CAD Alarm & Tag Propagation: A bi-directional interface allowing alarm and tag configurations to be sent from CAD to the D-SCADA for enforcement. The interface also allows for any alarm/tag violation notifications to be transmitted to CAD for a user to view and take appropriate action. All data exchanges in this interface are automatically transmitted via MQ.
E. D-SCADA/CAD Monitor and Control Propagation: A bi-directional interface allowing for D-SCADA point monitoring details to be provided to CAD so that it has all updated information for user display. The interface also allows for any controls resulting from user selections to be transmitted to D-SCADA for further propagation to devices in the field. All data exchanges in this interface are automatically transmitted via ICCP. Numerous configurations were required on custom XML files to support end-to-end communications with devices.
F. D-SCADA/CAD Data Model Propagation: As part of the overall network and data model propagation process from GIS to the DMS suite of systems, the key details of enabled devices, their correlated signal list configuration, and the broader network connectivity model are prepared in CAD and then transferred to the D-SCADA (IMM subcomponent). This process is performed on an ad-hoc and largely manual basis using Oracle SQL.
G. GIS/CAD Data Model Propagation: This is the first step in the overall network and data model propagation from GIS to the DMS Suite of Systems. This one way interface compiles pertinent GIS data and packages it for consumption by CAD where it is further augmented to achieve a broader network model. This process is performed on an ad-hoc and largely manual basis using Oracle SQL and other proprietary tools.

2.2.4.1.3 Post-Implementation Operational Issues

Following the standup, integration, and preliminary testing of the CAD system, numerous post-implementation operational issues needed to be mitigated and considered. These issues are as follows:

- Productized Integration – At the inception of the SGDP, deployment plans were based on the premise of a commercially mature, productized integration of the CAD capabilities with the First Responder (DNA), D-SCADA, OMS and GIS capabilities. However, this productized integration had only been deployed at one other site, which resulted in a larger stabilization effort in KCP&L's demonstration environment. This continued into the post-operational period, where very specific real-world situations conspired to result in system instability situations. Many of these situations could have been avoided had this system been deployed and fully tested in an enterprise operational context prior to implementation at KCP&L.
- Software Updates – Upon installation of the system at KCP&L, efforts were commenced to stabilize the system, perform SAT, and begin operating the system as situational opportunities arose. Throughout this period, numerous system deficiencies were discovered, and updates were proactively provided by the software vendor. These necessitated configuration fixes and/or service packs to be delivered by the software vendor. These fixes were delivered by the software vendor together for the OMS and CAD as they are closely integrated with each other. A list of all the service packs installed by KCP&L is listed below:

Build No.	Date	Content
A	4-1-2012	Initial Consolidated UI Installation for Phase 1 SAT
B	9-15-2012	Reinstallation of Consolidated UI with numerous fixes to accommodate advances for Phase 2 SAT
11	2-28-2013	Reinstallation of Consolidated UI with numerous fixes to accommodate advances for Phase 3 SAT
12	4-30-2013	Core UI variances needed to enable stability and advance SAT
13	6-30-2013	Core UI variances needed to enable stability and advance SAT
14	8-30-2013	Remaining high-priority variances to complete SAT
14A	9-16-2013	Fix for SCADA values blank in Feature Information Window
15	11-12-2013	Miscellaneous defect fixes to further stabilize system

- Network Model Data Migrations – During initial configuration and build efforts, only a subset of planned, end-state devices and their corresponding points were captured in the data model. This was done to reflect the limited number of deployed devices at configuration inception, but also to limit the complexity of model connectivity while establishing process stability. However, in the preliminary configuration and test environments, many of the attempted data migrations with this limited data set took significant time and effort to implement and stabilize. When the system was transferred to KCP&L, it maintained this subset of devices and due to the known challenges with the data migration process, incremental data migrations were not pursued for some time. This allowed time to complete device deployments in the field as well as setup and conduct numerous additional test data migrations in the lab environment prior to conducting a data migration in the demo environment. In retrospect, the lack of a complete data model was a hindrance requiring certain workarounds, but it was still preferable to the potentially long time periods of environment inaccessibility waiting for the data migration to re-stabilize.
- Tuning and Configurations – As the system was installed and stabilized at KCP&L, the Integrated UI (CAD) required several iterations of tuning and configuration to achieve a reasonable level of stability. Due to time constraints for implementation, several glyphs, job tables, meter data, and device locations were not initially "polished", but these items were prioritized and refined as needed. Furthermore, each functional alarm in InService had to be manually configured in InService; this was a tedious process which was pursued as staff availability allowed. Finally, numerous switch statuses on the CAD database had to be maintained during data migrations as point changes during this time could result in data synchronization issues.
- Device Connectivity and Directionality – When migrated from the GIS, the map data and network data model did not meet the DNA model requirements with respect to connectivity and flow of power. While the level of detail was sufficient for legacy applications, the required detail for DMS applications was more nuanced by orders of magnitude. As such, the migration process required multiple iterations to ensure appropriate connectivity in the distribution infrastructure. During subsequent testing with complete integration, it was further realized that the connectivity and directionality of power readings from reclosers were necessary for the First Responder applications to properly function and analyze data. As the Integrated UI was the core integration point from where the data model was transmitted to the rest of the system, the data model in CAD had to be modified to include device directionality from the GIS and properly display it for end-user consumption.

- Signal Point List Updates are Not Dynamic– As the project progressed, at several stages additional devices were added or deleted on to the system. At other times, data points on existing devices were modified based on new learnings and better understanding of data requirements for the system. In all cases, the Signal Points List for these devices was managed in the InService database and migrated onto the rest of the systems as part of the data migration process. This process was laborious as each point change for an existing or new device had to be manually entered into the Signal Point List tables without any templates or options to replicate existing device configurations. The availability of standard device templates for signal lists and the ability to copy existing points list to new devices would have made the process much more dynamic and less prone to error.
- Field Device Communications Instability – Consolidated UI (CAD) capabilities were dependent on the quality of SICAM and further downstream field device/substation data. While there were a handful of issues expressly tied to CAD's own ability to consistently display all current data from each field device, a majority of issues were due to these other systems and evidenced themselves in CAD indirectly. As discussed in greater detail in the SICAM and Tropos build sections, significant effort was put forth to stabilize the communications channels to field devices and ensure robust transmission of real-time data. At times where instability was significant, KCP&L's ability to have full monitor and control capability was limited and focus was shifted back to SICAM/Tropos stabilization.

2.2.4.1.4 Lessons Learned

Throughout the build and stabilization of the Integrated UI system, numerous considerations were realized and should be noted for future deployments of this sort. These Lessons Learned are as follows:

- Productized Integration – At the inception of the SGDP, deployment plans were based on the premise of a commercially mature, productized integration of the CAD capabilities with the First Responder (DNA), D-SCADA, OMS and GIS capabilities. However, this productized integration had only been deployed at one other site, which resulted in a larger stabilization effort in KCP&L's demonstration environment. This continued into the post-operational period, where very specific real-world situations conspired to result in system instability situations. Many of these situations could have been avoided had this system been deployed and fully tested in an enterprise operational context prior to implementation at KCP&L.
- UI Maturity and Analytics Presentation – The Integrated UI used for the DMS integrates several control room systems and applications into a single user interface as discussed above. This concept is relatively new and it is understood to be a still evolving representation and is yet to reach its zenith, but greater usage and feedback shall continually help improve it usability. Navigation of multiple windows and pop ups could be made more efficient for users. Analytics data from DNA applications and other systems could be shown in a more informative manner, particularly, with other presentation tools and styles such as graphs, charts, and device hover data to improve situational awareness for the user. Over the period of implementation, there have been several improvements based on KCP&L feedback and the user interface is already in route to evolving into a more ideal DMS UI.
- Quality of Real Time Values – During the implementation, it was observed that the user has access to view all the data points from the field on the integrated UI but is unable to determine the quality or currency of this data. The data points are reported to the system from the field only by exception or periodically. If a device has stopped communicating with the system, then CAD displays the last value reported by D-SCADA (good or bad) to the user without a quality or time stamp. The user cannot directly verify the quality (good,

bad, telemetered, non-telemetered, entered etc.) of the data currently being shown in CAD from within the application. To ensure progress, the testers and users at KCP&L have been directly using the D-SCADA application and monitoring the DDC System for establishing the quality of an analog, but from the perspective of an enterprisewide deployment this would be less than ideal.

- Initial Signal List Points Definition – In order to configure the points lists and tables in UI/CAD, an analysis of points on each group of devices was conducted). First Responder capabilities required a relatively small subset of the available points but considerations from groups such as asset management, engineering, and operations required a larger subset of the points. D-SCADA was thus set up to bring back and manage a large number of points available from every connected device and send them to UI/CAD via ICCP. Unfortunately, this volume of data stretched the technology to its limits resulting in numerous challenges to ensure stability through the integrated solution. On UI/CAD specifically, the large number of displayed points became unwieldy from an operational perspective. This would have been mitigated by an operator customizable points list or filtering options on UI/CAD.
- Communication Protocols and Naming Conventions – The ICCP protocol was used for transmitting control and monitoring data between the integrated UI (CAD) and the D-SCADA system. The 61850 protocol was used to transmit control and monitoring data to the substation and field device from the D-SCADA. Each of these protocols had different naming conventions and the data points from the same device had to be assigned different names when moving from one system to another. This difference in name required the creation of a "marriage" file placed in the DMS that aligned the different names for the same data point. The data migration process and SCADA list modification was a complicated process which de-stabilized the system for substantial amounts of time. Support of the marriage file with several names for the same data point created further data management issues. In the future, continuing evolution of technology and further adoption of standards should help to make implementations simpler.
- Incremental Device Communications Configurations – Where the prior note highlights the challenges in defining points applicable to an entire class of field device (e.g. reclosers or cap banks), KCP&L also encountered challenges when establishing communications to a single incremental device being installed. The points lists would be defined easily, but the configurations and synchronization between systems was highly manual. This required greater attention and user involvement with loading/verification at every step of the communication path and also in ensuring proper naming conventions, appropriate cross mapping between DNP and 61850 naming conventions. These efforts to enable substation and field device communications were a notable contrast to the deployment of incremental AMI meters in the field. In the same way that meters would self-identify and propagate communication point capabilities, other distribution devices would benefit from these same capabilities through to all systems with which they communicate.
- Incremental Network Model Management – In addition to the two previous considerations and as mentioned as a post-operational issue, the installation of a new network data model had significant timing considerations and complexity as it was an all-or-nothing implementation. While this step was vital to allow enabled D-SCADA capabilities to be geospatially displayed on the Consolidated UI, the team was hesitant about deploying any new field devices or circuits into the maps because the entire network model needed to be re-deployed. This resulted in significant system downtime to install and re-stabilize the system. In this context, an incremental network management migration capability would have significantly greater value to a real-time system like the

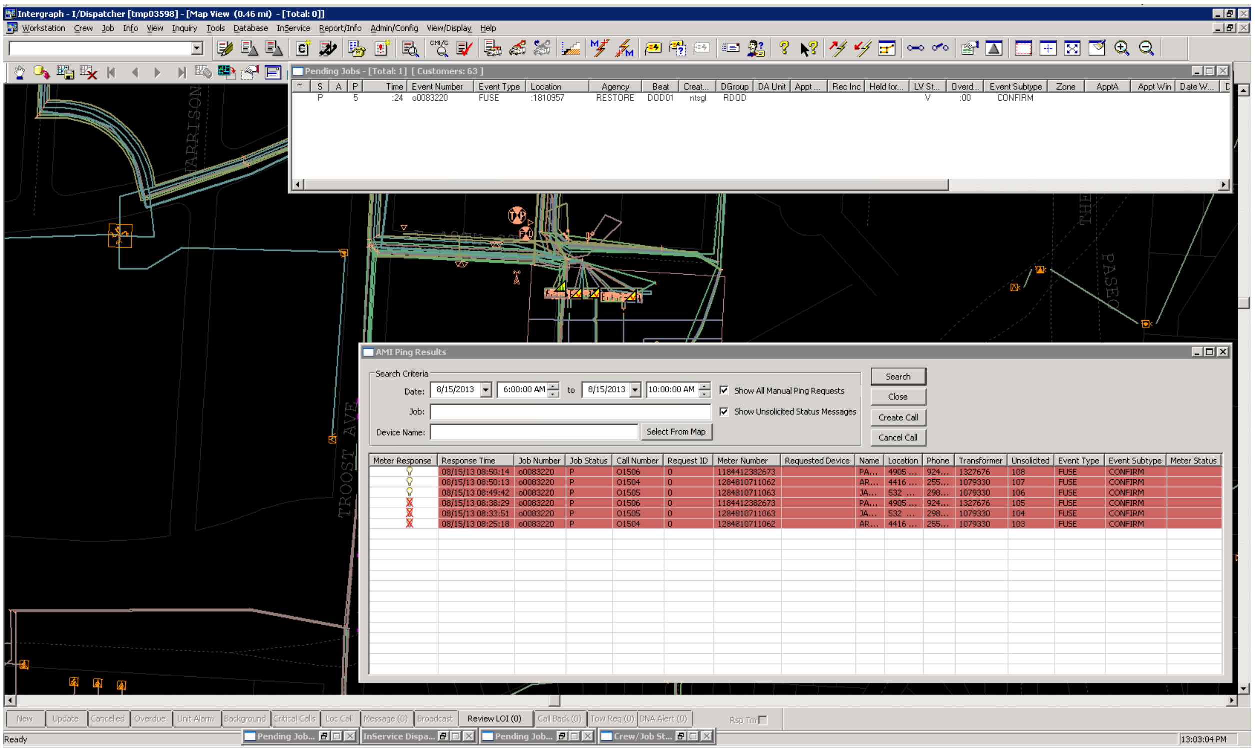
Consolidated UI as it would allow the system to maintain its functionality for vast portions of the service territory while only a small, targeted section is having its underlying connectivity details updated.

- ICCP & MQ Connectivity Failure Awareness – As the central device status display and control broker in the integrated solution, the CAD heavily uses ICCP and MQ protocols to transmit and receive data from the D-SCADA. Independently, any singular interface has relatively high reliability and stability. Unfortunately, given the vast integration of this project, the small instabilities incumbent in each interface combine with each other and multiply to a general state of frequent communication instability across the entire platform. From a user perspective, the systems only reactively show that end-to-end communications are not working. Upon notification to the project support team, a more detailed investigation is conducted to resolve. However, each instance of communication failure erodes user confidence in the system's ability to reliably perform when it matters. As a result, it has become apparent that as operations become more reliant on highly integrated systems such as this, it is vital to have additional capabilities serving as an IT Network Operations Center. The project team envisions that this function would proactively monitor system communications and ensure consistently higher levels of platform-wide communications and system stability.
- Cross-Platform Time Synchronization – Building on the communication stability challenges mentioned previously, a complicating factor in the diagnosis was the general synchronization of time stamps across all devices and systems. A synchronized time stamp is very important in this type of diagnostic to see when certain signals depart one system and arrive at another. In a context of multiple communications from different devices all being recorded in communications logs, if one system is off by even a couple seconds, then the analysis of different data exchanges is complicated by crisscrossed message streams. The KCP&L time synchronization effort was particularly challenged because different systems used multiple time-synch mechanisms: Substation devices from satellite clock, servers derived from network time, field devices synched to SICAM. KCP&L's current enterprise configuration doesn't have a strict requirement for synchronized data as the end-state use of this information is more forgiving in its application. However, this legacy challenge became of greater concern with the advanced applications of the DMS as its algorithms have an increased reliance on timely and synchronized inputs to achieve expected results. Significant effort was put forth to achieve synchronization throughout the demonstration footprint and additional efforts would be required to establish the importance of this throughout KCP&L's culture if it were to be expanded enterprisewide.
- Operational Control Authority Management– The overall DMS System has several modes of controlling the field devices such as Complete User Control, Open Loop Control, and Closed Loop Control. Furthermore, considerations of Centralized Control (from the control center) and Distributed Control (from the DCADA located at the substation) pervade this implementation. The user or operator is the supreme authority for deciding who is in control: a user or an autonomous system. The user can assign control to an application and take it away at will Using the Control UI application hosted on the entire system. The Control UI can transfer control between user and DNA at a higher level but is disconnected from the internal workings of DNA. If DNA relinquishes control then neither the DNA nor the user can run the applications in closed loop until the user assigns the control back in Control UI.. This process works but is cumbersome and not entirely operator friendly. With an anticipated future where multiple systems integrate together forming a single DMS, there is a need for a single hierarchical control system that interacts with all systems yet still gives complete authority to operator at needed times.

2.2.4.2 Outage Management System

The Intergraph OMS is the basis for all outage information and provides the ability to view that status of all grid outages and to safely manage day-to-day and emergency restoration work as illustrated in Figure 2-52. The following sections provide a summary of the development and configurations that were required to implement and deploy the OMS functionality.

Figure 2-52: KCP&L SmartGrid OMS User Interface



2.2.4.2.1 Build

KCP&L's OMS implementation efforts were launched by assembling a team of highly skilled individuals that would pursue and support the deployment of these advanced systems. The goal was to upgrade and integrate the legacy control room system into a broader Distribution Management System so that Distribution Operations users could access all important information relating to customer and network outages from a single user interface. To familiarize themselves with the goals of the project, the team began by reviewing previously created Use Cases to understand new processes and anticipated system functions. These Use Case documents were finalized where possible and provided to Intergraph to establish their baseline understanding of what KCP&L hoped to achieve with the system implementation. The use cases served as a solid foundation of understanding for newer team members. Where clarifications were required, they were addressed during the Design/Configuration Workshops.

In parallel to KCP&L's preliminary use case familiarization efforts, Intergraph began establishing its project team to perform the installation. The OMS's core capabilities and interfaces are part of a commercially available, productized software implementation which can be configured to the needs of a given customer. By pursuing this "off-the-shelf" philosophy to the maximum degree possible, limited custom design was required. However, the systems did require configuration to accommodate KCP&L's distribution system. With this in mind, Intergraph created a System Configuration Diagram based on discussions with KCP&L to better understand the system configuration and requirements. Intergraph then developed a detailed plan which outlined the time required to meet these requirements and configure the system per KCP&L's needs. As there were relatively few implementations of this integrated DMS solution, staff began familiarizing themselves with the key configuration elements required and documenting questions to be answered in preparation of the actual configuration efforts.

2.2.4.2.1.1 Collaborative Design Sessions

After the preliminary familiarization efforts conducted by KCP&L and Intergraph, several workshops were conducted to expedite the configuration effort. The First Responder and Facility Migration Design workshop was conducted to review the details of First Responder data required and KCP&L's existing mapping technologies. The DMS InService Integration Design workshop (focused on D-SCADA integration) was held in which Siemens, Intergraph, and KCP&L jointly participated in this workshop to ensure that all parties were in agreement about the design and configurations to be pursued. Specifically, analysis was performed on the CAD and how it would work with Siemens' D-SCADA (PowerCC) via productized integration. To this end, a foundational understanding of the overall model build process was also established. At the close of the workshop, KCP&L had a better understanding of what additional data requirements needed to be compiled and provided as it became available. Siemens and Intergraph left with a better defined set of requirements that they could use to begin their efforts.

During the InService Integration workshop there were also several discussions regarding the AMI, CIS, and how both integrate with the OMS and CAD. There were additional discussions on accessing data from the CIS in a format as required by Intergraph and the usage of MQ interface for AMI and MDM communications. KCP&L and Intergraph had substantial discussion on alarming and the required applications that would generate alarms on the Integrated UI from the native InService systems and the various other systems that would be integrated with the CAD. The DNA applications that were to be incorporated into the UI and their data requirements were also discussed and determined. Finally, all involved parties worked on technical specifications to ensure coordinated development of the interfaces to develop the standards-based messages that would be used to exchange the agreed upon information.

2.2.4.2.1.2 System and Interface Configuration

After establishing requirements, configuration considerations, environmental parameters, and a schedule fully recognizes and accommodates dependencies, then development and configuration efforts could begin in earnest. Due to its integrated nature, the OMS was installed alongside the CAD during earlier phases even though it was only minimally used. Both Phases 1 and 2 followed the same configuration approach. Intergraph consolidated all configuration data provided along with all requirements and began working independently in the vendor environment. Numerous iterations of configuration and isolated testing were performed to establish preliminary functionality. As conditions warranted, Intergraph coordinated joint working sessions with Siemens to work through integration efforts with the D-SCADA system (also co-located in the vendor environment). For Phase 3 scope, significantly greater effort was expended to ensure that the Outage Restoration and Power Status Verification functions were working in addition to the core outage prediction and management capabilities. Later, as the preliminary configurations were coming together, KCP&L facilitated daily working sessions between KCP&L, Siemens, and Intergraph to ensure a comprehensive and synchronized understanding of the deployment in some of its most nuanced ways. Shared-desktop technology (WebEx) was used extensively to enable these conversations between remote participants by allowing everyone to see the same system function, defect, or configuration process.

2.2.4.2.1.3 Data Model Migration

While numerous configuration efforts were vital pre-requisites to create a DMS data model that the OMS component could use for all of its algorithms, a particularly laborious component was the DMS InService I/Dispatcher model build process discussed previously and illustrated in Figure 2-50.

The OMS captures the outages in the real-time system and displays it to the operator for further investigation enabling restoration of service customers. The outages are stored in tables and displayed on the map in Intergraph's I/Dispatcher. The GIS is the original source of the network model utilized by the system and it must be kept up to date so as to predict the outages accurately. The map is preliminarily extracted from GIS in which the data elements are standardized for migration. The extracted distribution system map from GIS is saved as a DGN file. The DGN file is then manually reviewed and, if needed, required tweaks in the map can be applied. Since, the SGDP area is limited to the Green Impact Zone the map is tweaked and edited as per the requirements and geographical area. This edited and updated map is now ready as an input to be augmented through the Network Model creation process.

During the design sessions, the project team determined that the since the existing GIS network model has been supporting a legacy OMS system and had been developed containing nearly all electrical and operational devices only minor enhancements would be needed to support the needs of the InService OMS. To ensure the completeness and accuracy of the GIS model within the SGDP area, the project team conducted a field verification of electrical connectivity and phasing and updated the GIS prior to initiating the GIS model exchange.

Initial migration efforts were performed in the vendor environment and numerous iterations were conducted. These iterations served the dual purpose of ensuring a quality automation process (in anticipation of numerous data model migrations supporting ongoing device deployment) as well as overall data quality (to validate properly synchronized between devices allowing for end-to-end communications). The KCP&L project team worked diligently with Siemens and Intergraph to understand the data model propagation as well as the behind-the-scenes implications of various configurations.

2.2.4.2.1.4 Training

The KCP&L team learned a tremendous amount during the workshops and joint configuration sessions. However, formalized training was still deemed very important to allow KCP&L users to prepare for formalized testing efforts and ultimately successful operation of the system. Sessions were conducted in-person and numerous training manuals were available to aid the process. In addition, given the previously established successes with WebEx, KCP&L leveraged this technology in a two-fold manner: 1) many training sessions were broadcast via WebEx which allowed targeted vendor subject matter experts to augment materials presented by the official trainer and 2) training was recorded allowing for ease of referencing back to better understand an explanation or sequence of events. The following table outlines training sessions conducted for OMS functionality:

Training Course	Dates
I/Dispatcher Training (Intergraph)	07/31/2012 through 08/02/2012
Tester Training (Intergraph and Siemens)	08/13/2012 through 08/14/2012
Alarm Configuration (Intergraph)	10/8/2012
Switch Planning (Intergraph)	10/9/2012 through 10/10/2012

2.2.4.2.1.5 Testing

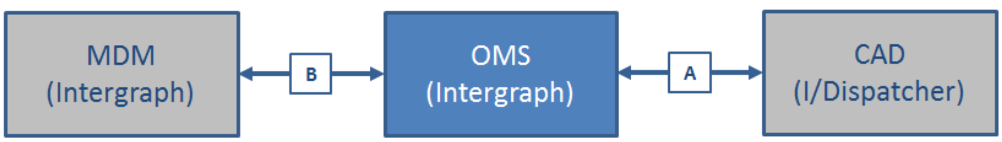
As outlined above, the more advanced training sessions provided an opportunity for in-depth reviews of functionality to learn how the system is operated. In addition, due to the significantly advanced configuration by this time, the training sessions in the vendor environment also provided an opportunity for KCP&L's testing team to select a subset of tests from the formalized test books and review their workability during the training sessions. Additionally, Siemens and Intergraph performed an extensive "Pre-FAT" test where they internally verified that all functionality listed in the test books were working as expected. During more formalized testing, the core outage management capabilities were reviewed with particular attention paid to the integration efforts to support the Outage Restoration and Power Status Verification data flows. Due to the complexities of this interface in particular, testing advanced in a more ad-hoc manner whereby Subject Matter Experts (SMEs) were convened to execute tests only when identified dependencies were resolved.

All testing efforts resulted in numerous defects being documented where functionality deviated from established requirements. Intergraph worked to remediate these defects as soon as they were discovered and continued working to remediate throughout 2013; as variances were fixed, new service packs would be compiled on a regular schedule and installed to KCP&L's lab and demo environments for re-testing.

2.2.4.2.2 Integration

An overview of OMS system-to-system interfaces and applicable messages is illustrated in Figure 2-53.

Figure 2-53: KCP&L SmartGrid Demonstration Project OMS Integration



The OMS (Intergraph) is the component of the overall DMS that manages the various outages, crews, new and pending jobs, and outage predictions. Meter outage, restoration data, and power status verification data are accessed on the Integrated UI, but this data is transmitted from the OMS, through the OMS. The OMS is capable of analyzing outage notifications from CIS, integrated voice response (IVR), and the automated metering infrastructure to provide outage notifications and pin-point troubled areas using the trouble analysis service. The CAD is the core system with the network model and base data from which the OMS performs its numerous functions. The OMS has a integration points with the CAD and the MDM systems as follows:

A. OMS/CAD Proprietary Integration: A bi-directional interface that allows outage information, crew data, new/pending jobs, and outage aggregations/predictions to be sent from the OMS to the CAD for the user to view and take appropriate action. This interface also allows the user to access meter data from the MDM, send meter pings, and receive power status verification messages from the meter through the OMS. All data exchanges are automatically transmitted through Intergraph's proprietary technology.

B. OMS/MDM Outage Restoration and PSV Propagation: A bi-directional interface allowing for meter outage and restoration data to be sent between the MDM and the OMS. Data from AMI systems can provide early identification of outages, assist in determining outage extents, and be used to verify power restoration to customers involved in outages. This interface also allows for PSV Requests and Responses to be sent and received between the OMS and MDM. All data exchanges in this interface are via the KCP&L ESB using MQ.

2.2.4.2.3 Post-Implementation Operational Issues

Following the standup, integration, and preliminary testing of the OMS system, numerous post-implementation operational issues needed to be mitigated and considered. These issues are as follows:

- Software Updates – Upon installation of the system at KCP&L, efforts were commenced to stabilize the system, perform SAT, and begin operating the system as situational opportunities arose. Throughout this period, numerous system deficiencies were discovered, and updates were proactively provided by the software vendor. These necessitated configuration fixes and/or service packs to be delivered by the software vendor. These fixes were delivered by the software vendor together for the OMS and CAD as they are closely integrated with each other. A list of all the service packs installed by KCP&L is listed below:

Build No.	Date	Content
A	4-1-2012	Initial Consolidated UI Installation for Phase 1 SAT
B	9-15-2012	Reinstallation of Consolidated UI with numerous fixes to accommodate advances for Phase 2 SAT
11	2-28-2013	Reinstallation of Consolidated UI with numerous fixes to accommodate advances for Phase 3 SAT
12	4-30-2013	Core UI variances needed to enable stability and advance SAT
13	6-30-2013	Core UI variances needed to enable stability and advance SAT
14	8-30-2013	Remaining high-priority variances to complete SAT
14A	9-16-2013	Fix for SCADA values blank in Feature Information Window
15	11-12-2013	Miscellaneous defect fixes to further stabilize system

- Outage/Restoration and PSV Data Issues– During initial configuration and testing at the KCP&L site it was observed that the Outage and Restoration data, PSV requests, and responses were not being picked from the ESB by the OMS application. Subsequently, numerous configuration changes were incorporated into the OMS to better enable the data transfer. These changes were then thoroughly tested on site with regular improvements and continuous vendor involvement. The meter outage/restoration data is crucial for the OMS to manage outages, escalate criticality, perform analysis to determine the probable source of an outage, and finally, PSV data to ensure restoration of power to all impacted customers.

  Occasionally, the OMS system services would hang-up. This would cause the OMS to fail to pick up outage/restoration messages, send PSV requests, or receive PSV response until the hang-up was discovered and the services were restarted.

  Unreliable VPN connectivity with the MDM vendor would cause PSV messaging to be dropped when passing through the MDM. This would cause PSV requests to time out and appear as “meter status unknown” to the OMS operator. While not an OMS issue directly, this did impact the PSV process from an OMS operator perspective.

2.2.4.2.4 Lessons Learned

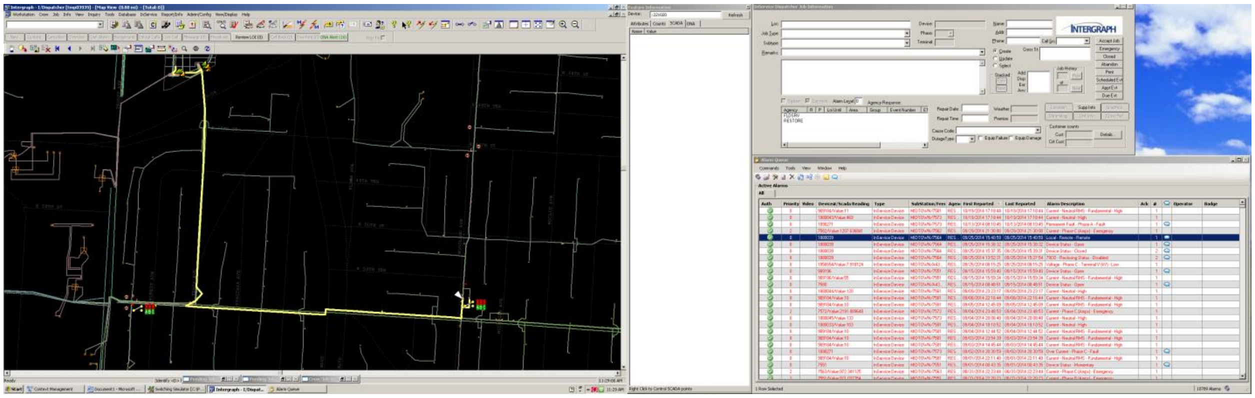
Throughout the build and stabilization of the OMS system, numerous considerations were realized and should be noted for future deployments of this sort. These Lessons Learned are as follows:

- Incremental Network Model Management – In addition to the two previous considerations and as mentioned as a post-operational issue, the installation of a new network data model had significant timing considerations and complexity as it was an all-or-nothing implementation. While this step was vital to allow enabled D-SCADA capabilities to be geospatially displayed on the Consolidated UI, the team was hesitant about deploying any new field devices or circuits into the maps because the entire network model needed to be re-deployed. The result of which was significant system downtime to install and re-stabilize the system. In this context, an incremental network management migration capability would have significantly greater value to a real-time system like the OMS as it would allow the system to maintain its functionality for vast portions of the service territory while only a small, targeted section is having its underlying connectivity details updated.
- Outage Prediction Roll-Up Management – The outage roll-up parameters are configurable within the OMS to predict outages at the transformer, fuse, recloser, and feeder breaker levels based on outages received compared against the network model. It is important to properly configure these outage prediction roll-up parameters based on the network model and the OMS system operator needs.
- Outage/Restoration Event Reliability – The outage and restoration events implemented by the L+G AMI were much more reliable than what KCP&L has experienced with the traditional “last gasp” events.
  - When power is lost, the AMI meter has waits approximately 30 seconds before it broadcasts a power outage event. This eliminates “last gasp” broadcasts caused my momentary interruption’s. The meters continue communicating for an additional 60 seconds to ensure that the event messages are transported through the mesh network. KCP&L’s experience is that the AHE receives over 90% of power outage events, far superior to the 25% experienced with the legacy AMR system.
  - When power is restored, the meter starts an internal timer that is used to calculate the restore time once the network is reestablished and network time is reset in the meter. The meter sends a first power restoration event message when the network communications are reestablished. A second power restoration event message is sent 5 minutes after network communications as a precaution in case the network backhaul was not fully established when the first message was sent. The majority of power restoration messages have typically been received by the AMI Head End within 5 minutes of the actual power restoration and that 95% of the power restoration events are typically received within 15 minutes.

2.2.4.3 Distribution-SCADA

The Siemens D-SCADA component provides real-time device and automation information to keep the operating model as close as possible to the real conditions in the field. D-SCADA provides all real-time data services and control agent capabilities for the combined Siemens/Intergraph DMS solution as illustrated in Figure 2-54. The following sections provide a summary of the development and configurations that were required to implement and deploy the desired D-SCADA functionality.

Figure 2-54: KCP&L SmartGrid D-SCADA User Interface



2.2.4.3.1 Build

KCP&L's D-SCADA (PowerCC) implementation efforts were launched by assembling a team of highly skilled individuals that would pursue and support the deployment of these advanced applications. To familiarize themselves with the goals of the project, the team began by reviewing previously created Use Cases to understand new processes and anticipated system functions. These Use Case documents were finalized where possible and provided to Siemens to establish their baseline understanding of what KCP&L hoped to achieve with the system implementation. Where clarifications were required, they were addressed during the Design/Configuration Workshops.

In parallel to KCP&L's preliminary use case familiarization efforts, Siemens began establishing its project team to perform the installation. The D-SCADA core capabilities and interfaces are part of a commercially available, productized software implementation which can be configured to the needs of a given customer. By pursuing this "off-the-shelf" philosophy to the maximum degree possible, limited custom design was required. However, the systems did require configuration to accommodate KCP&L's distribution system. In this context, Siemens began identifying key staff and subject matter experts who would be performing the configuration. As there were relatively few implementations of this product, staff began familiarizing themselves with the configuration elements required and documenting questions to be answered in preparation of the actual configuration efforts.

2.2.4.3.1.1 Collaborative Design Sessions

After the preliminary familiarization efforts conducted by KCP&L and Siemens, a workshop was conducted to expedite the configuration effort. Siemens, Intergraph, and KCP&L jointly participated in this workshop to ensure that all parties were in agreement about the design and configurations to be pursued. Specifically, analysis was performed on Intergraph's Computer Aided Dispatch (CAD) application (I/Dispatcher) and how it would work with Siemens' D-SCADA (PowerCC) via productized integration. A key element of the workshop was a detailed matrix outlining the data points required from each device to support proper algorithmic processing in the First Responder (DNA) applications; this formed the basis for follow-on signal list definition efforts. To this end, a foundational understanding of the overall model build process was also established. All parties were keenly aware that the signal list definition was central to forward project momentum and that numerous iterations of a model build would be required for stability and full device inclusion through the integrated D-SCADA. At the close of the workshop, KCP&L had a better understanding of what additional data requirements needed to be compiled and provided as it became available. Siemens left with a better defined set of requirements that they could use to begin their efforts.

The DMS/DERM interface, however, differed from the productized solution in that it is a custom interface between Siemens and OATI for the SGDP. In order to design the message exchanges for this interface, KCP&L, Siemens, and OATI met for several days to create additional use cases for the possible scenarios. The main scenarios that were detailed included:

- Initialization scenario between DMS and DERM – used the first time a new database is applied or after one of the systems has been restarted
- Feeder load management scenario –this is an exchange between the DMS and the DERM done in a planning mode and executed from a DMS "study case"
- Feeder load shed or "emergency" scenario–this is an exchange between the DMS and the DERM done in real time when an overload has occurred.

Upon completion of the DMS/DERM use cases, all parties worked on technical specifications for these interfaces to develop the standards-based messages that would be used to exchange the agreed upon information.

KCP&L concluded the series of workshops with the recognition that a detailed signal list was required to configure specific points applicable to specific devices. KCP&L started by detailing those points required by Siemens for the First Responder applications to run. However, KCP&L found there to be hundreds of additional data points that could be brought back from each of the devices to the data concentrator. KCP&L conducted numerous discussions to establish internal agreement on the set of points that might be useful for operational activities outside of the DNA applications and provided these signal lists to Siemens for their configuration efforts.

2.2.4.3.1.2 System and Interface Configuration

After establishing requirements, configuration considerations, environmental parameters, and a schedule that recognizes and accommodates dependencies, then development and configuration efforts could begin in earnest. Both Phases 1 and 2 followed the same configuration approach. Siemens consolidated all configuration data provided along with all requirements and began working independently in the vendor environment. Numerous iterations of configuration and isolated testing were performed to establish preliminary functionality. As conditions warranted, Siemens coordinated joint working sessions with Intergraph to work through integration efforts with the CAD system (also co-located in the vendor environment). Additional working sessions were conducted with another Siemens team responsible for the First Responder capabilities to ensure proprietary integration with that system was working as expected. Later, as the preliminary configurations were coming together, KCP&L facilitated daily working sessions between KCP&L, Siemens, and Intergraph to ensure a comprehensive and synchronized understanding of the deployment in some of its most nuanced ways. Shared-desktop technology was used extensively to enable these conversations between remote participants by allowing everyone to see the same system function, defect, or configuration process.

2.2.4.3.1.3 Data Model Migration

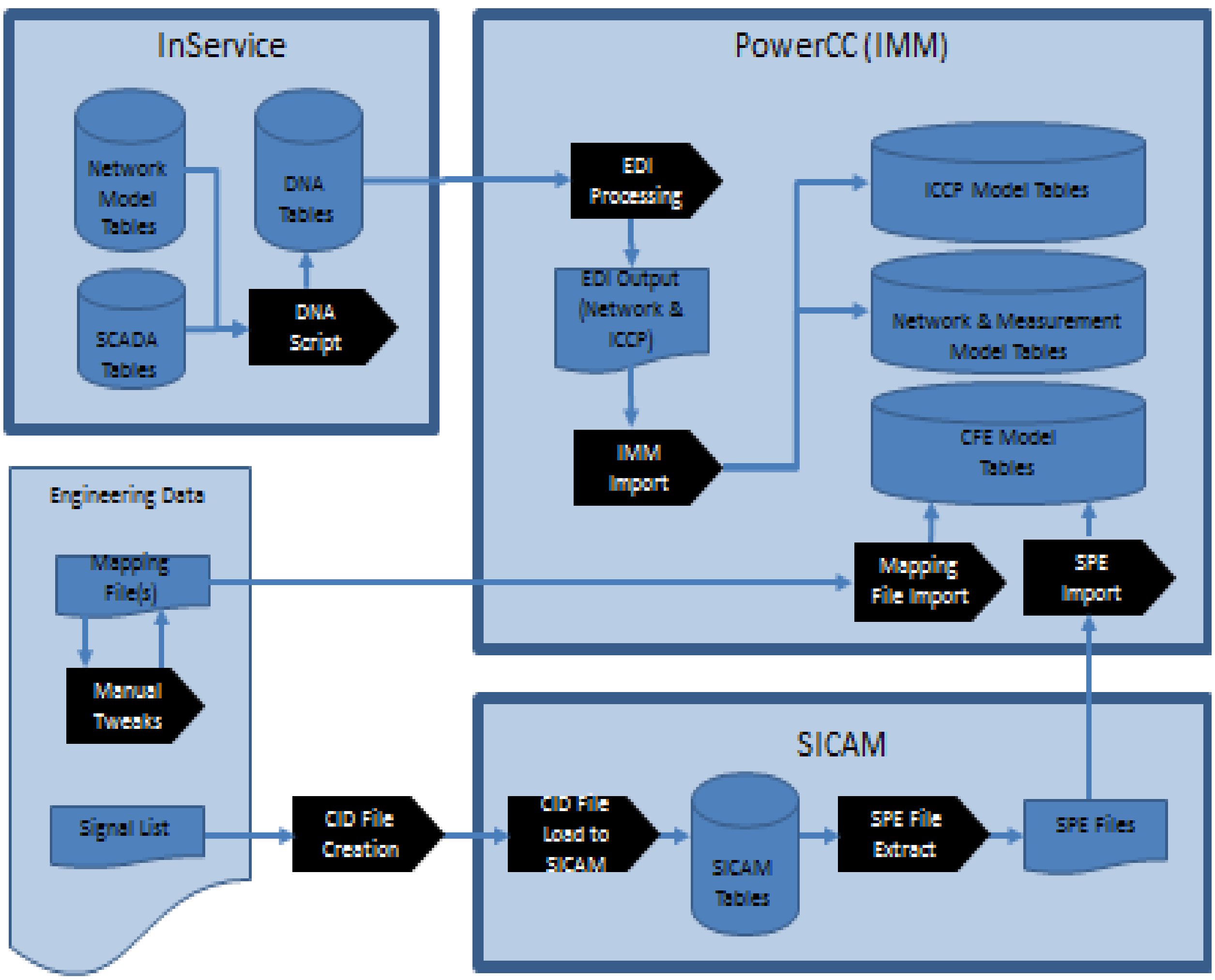
While numerous configuration efforts were vital pre-requisites to create a data model that the D-SCADA, DNA and SmartSubstation components could use for all of its algorithms, a particularly complex component was the PowerCC Information Model Management (IMM) model build process illustrated in Figure 2-55. The process involves leveraging the productized InService/PowerCC integration, data from the previously described InService Data Model Migration, linking to various other systems, execution of several proprietary scripts and extensive manual intervention for configurations and modifications.

During the design sessions, the project team determined that several manipulations of the InService network model would be required for the IMM model to support the D-SCADA and DNA functionality. These modifications included:

- Convert line transformers to fuses and nodes with corresponding loads.
- Convert capacitors to fuses and nodes with corresponding loads.

Initial model migration efforts were performed in the vendor environment and numerous iterations were conducted. These iterations served the dual purpose of ensuring a quality automation process (in anticipation of numerous data model migrations supporting ongoing field device deployments) as well as overall data quality (to validate properly synchronized data between devices allowing for end-to-end communications).

Figure 2-55: Siemens IMM Model Build Process



The KCP&L project team worked diligently with Siemens and Intergraph to understand the data model propagation process, as well as the behind-the-scenes implications of various configurations. Through much iteration and effort, the data migration process was stabilized, but it consumed far more time than initially planned. Upon stabilization of the base model build, efforts then commenced to support the model migration to the DERM and progressed similarly.

The PowerCC IMM model build process is explained in detail in the following paragraphs.

The D-SCADA is the main data broker for the PowerCC DMS where pertinent data is routed to and from the CAD, DNA, and DDC. The communication protocol D-SCADA uses to communicate with CAD (ICCP Inter-Control Center Communication Protocol) has major differences from the protocol used to communicate with the DDC (IEC 61850) that include, but also transcend, mere naming conventions. This resulted in two major data migration processes which catered to the respective configuration needs of each protocol:

- CAD and DNA Communications: Generate pertinent D-SCADA tables utilizing previously migrated data which enabled functionality in CAD
- DDC Communications: Generate pertinent D-SCADA tables utilizing manually created Mapping Files and SICAM-created SPE files.

CAD and DNA Communications: The SCADA Tables, along with the Network Model Tables residing in CAD constitute the major data sources which must be processed for downstream consumption. In addition to real-time schedules, a proprietary DNA Script executed in CAD leverages these various inputs to generate a staging table of contents known as the DNA Tables. These DNA Tables are then manually transferred to the D-SCADA database IMM where they are run through EDI Processing in D-SCADA to be converted to CIM formatted XML files. In a final step of this part of the process, the IMM Import script processes these EDI Output files into two families of tables within the database (ICCP Model Tables and the Network & Measurement Tables).

DDC Communications: The Signal Lists applicable to the real world devices and their points are optimized manually to incorporate modifications and any recent updates. These optimized Signal Lists are leveraged by proprietary software to create CID Files for all substation and field devices. The CID Files conform to 61850 protocols and define the data-element communications relationship between the DDC (client) and the Field Devices (server). The files are then loaded into the DDC to finalize this relationship by populating the DDC database (SICAM Tables). In order to establish preliminary D-SCADA communications, the SPE File Extract process extracts pertinent data from the SICAM Tables and creates SPE Files which further defines the communicating relationship between DDC (client) and the D-SCADA (server). The SPE Files are then used by the SPE Import process to load data to the CFE Model Tables to enable basic SCADA controls. However, for full end-to-end communications with CAD, additional data is required as the CAD references points by their ICCP name and the DDC references points by their 61850 names (or 61850-like name for the DNP field devices). This necessitated significant manual effort to ensure that all name references were properly synchronized between the CAD and the DDC. After many challenging iterations on this manual process, the finalized Mapping File is processed by the Mapping File Import to further configure the CFE Model Tables which map the ICCP point names with their corresponding 61850 point names in support of cross-platform connectivity.

2.2.4.3.1.4 Training

The KCP&L team learned a tremendous amount during the workshops and joint configuration sessions. However, formalized training was still deemed very important to allow KCP&L users to prepare for formalized testing efforts and ultimately successful operation of the system. Sessions were conducted in-person and numerous training manuals were available to aid the process. In addition, given the previously established successes with WebEx, the project team leveraged this technology in a two-fold manner: 1) many training sessions were broadcast via WebEx which allowed targeted vendor subject matter experts to augment materials presented by the official trainer and 2) training was recorded allowing for ease of referencing back to better understand an explanation or sequence of events. The following table outlines training sessions conducted for D-SCADA functionality.

Training Course	Dates
I/Dispatcher Training (Intergraph)	07/31/2012 through 08/02/2012
Tester Training (Siemens)	08/13/2012 through 08/14/2012

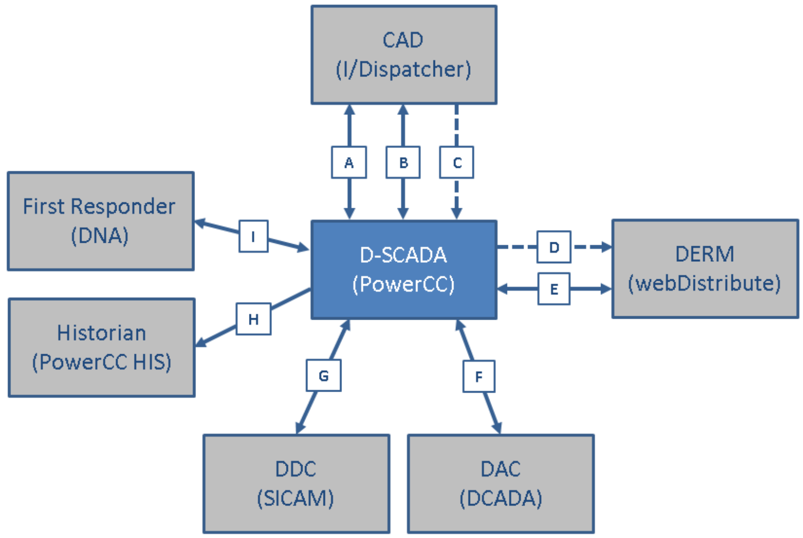
2.2.4.3.1.5 Testing

As outlined above, the more advanced training sessions provided an opportunity for in-depth reviews of functionality to learn how the system is operated. In addition, due to the significantly advanced configuration by this time, the training sessions in the vendor environment also provided an opportunity for KCP&L's testing team to select a subset of tests from the formalized test books to ensure the accuracy of the configuration. Additionally, Siemens performed an extensive "Pre-FAT" test where they internally verified that all functionality listed in the test books was working as expected. Formal testing efforts commenced with the Phase 1 Factory Acceptance Testing where KCP&L staff travelled to the Siemens facility and watched a demonstration of the D-SCADA capabilities originating with substation device value changes through SICAM and D-SCADA and culminating with a display in the CAD. The highest criticality defects were immediately rectified and the servers were sent to KCP&L for installation to the Midtown Substation (demo environment). The system was stabilized and a robust SAT was performed to ensure that the systems were able to properly transmit device monitoring signals between servers. Later, as configuration progressed, Phase 2 FAT was performed but deviated slightly as required by the defined scope. Specifically, substation devices remained at the Siemens facility and this time testing ensured appropriate monitor and control capabilities. Field devices were tested differently, as the devices remained in KCP&L facilities (lab environment). The field devices were connected to a WAN and then they communicated with SICAM and D-SCADA in the Siemens facility. This testing required some portion of the test team to remain at KCP&L to verify synchronization with the test efforts being conducted at Siemens. Again, the highest criticality defects were immediately rectified and additional servers were then sent to KCP&L for installation to the Midtown Substation (demo environment). The system was again stabilized and a robust SAT was performed to ensure that the systems were able to properly transmit monitoring and control signals to/from substation and field devices. With stabilized communications in both environments, efforts shifted to testing communications with the DERM. See Section 2.2.5.1.1 for details about the DMS/DERM integration and testing efforts. Throughout the FAT and SAT for both phases, where needed, defects were documented and logged with a tag corresponding to the appropriate testing effort.

2.2.4.3.2 Integration

An overview of D-SCADA system-to-system interfaces is illustrated in Figure 2-56.

Figure 2-56: KCP&L SmartGrid Demonstration Project D-SCADA Integration



The D-SCADA capabilities are central to many functions of the larger integrated system. In particular, it is a specialized system managing real-time data and acts as the central broker ensuring that necessary data is appropriately exchanged between different DMS components. The integration touch points for the D-SCADA applications are as follows:

A. D-SCADA/CAD Alarm & Tag Propagation: A bi-directional interface allowing alarm and tag configurations to be sent from CAD to the D-SCADA for enforcement. The interface also allows for any alarm/tag violation notifications to be transmitted from D-SCADA to CAD for a user to view and take appropriate action. All data exchanges in this interface are automatically transmitted via MQ.
B. D-SCADA/CAD Monitor and Control Propagation: A bi-directional interface allowing for D-SCADA point monitoring details to be provided to CAD so that it has all updated information for user display. The interface also allows for any controls resulting from user selections to be transmitted to D-SCADA for further propagation to devices in the field. All data exchanges in this interface are automatically transmitted via ICCP. Numerous configurations were required on custom XML files to support end-to-end communications with devices.
C. D-SCADA/CAD Data Model Propagation: As part of the overall network and data model propagation process from GIS to the DMS suite of systems, the key details of enabled devices, their correlated signal list configuration, and the broader network connectivity model are prepared in CAD and then transferred to the D-SCADA (IMM subcomponent). This process is performed on an ad-hoc and largely manual basis using Oracle SQL.
D. D-SCADA/DERM Data Model Propagation: In addition to the overall network and data model propagation process from GIS to the DMS suite of systems, the DERM system must have its data model synchronized with D-SCADA to make accurate calculations of its own. The network connectivity model and associated loads are transferred from the DMS to the DERM using a manual CIM RDF export. Generation of the CIM RDF file is done in the IMM and then exported via file transfer to OATI. This process is performed whenever a new data model is taken from the GIS, and it requires massaging from OATI to ensure that it's properly digested by the DERM.
E. D-SCADA/DERM Dynamic Data Exchange: In addition to the static model data that's exchanged between the DMS and the DERM, the two systems also exchange a number of

dynamic messages on an as-needed basis. The DERM sends and receives Web services messages, whereas the DMS sends and receives JMS (Java Messaging Service) messages, so adapters within KCP&L's ESB serve as translators between the two systems. The dynamic data exchanged between the DMS and the DERM can be categorized by the following interfaces:

- Network Topology Interface – Upon initial synchronization of the two databases, the DERM is notified about each switch state change.
- Distribution Power Flow (DPF) Interface – The DPF interface allows the DERM to query DPF results from the DMS. For scheduled DERM events, the DERM needs calculated overloads on an hourly basis. The DPF interface generates the data and makes it available to DERM. Additionally, violations are published to the DERM in real time.
- Study Case Interface – When study cases are created in the DMS, a study case needs to be created in the DERM, as well. This interface provides the messages to do so.
- Demand Response Event Interface – DR events affect power flow results, so DERM needs an interface for publishing DR events to the DMS.
- Battery Interface – The DMS is used as the control authority for the battery, so this interface is used to dispatch DR events for this purpose.

F. D-SCADA/DAC Data Model and Delegated Control Propagation: A bi-directional interface allowing for data model updates to be propagated to the DAC as required to stay synchronized during real-time changes (particularly for cut/jumper updates). The interface also allows for transmission of delegated control permissions to be exchanged between systems to ensure synchronization of SCADA mastership. All data exchanges in this interface are automatically transmitted via proprietary protocols.

G. D-SCADA/DDC Monitor and Control Propagation: A bi-directional interface allowing for D-SCADA point monitoring details to be provided by the DDC (SICAM) so that it has all updated information for propagation to other systems. The interface also allows for any controls resulting from upstream user selections to be transmitted to the DDC (SICAM) for further propagation to devices in the field. All data exchanges in this interface are automatically transmitted via 61850 protocols.

H. D-SCADA/HIS Data Archival via Oracle: A one-way interface allowing for D-SCADA point monitoring details to be provided to the Historian so that it has all updated points list details for each configured device. This archive then provides the basis for analysis of all DMS capabilities through the demonstration period. All data exchanges in this interface are automatically transmitted using Oracle SQL.

I. D-SCADA/DNA Monitor & Control Propagation: A bi-directional interface allowing for D-SCADA point monitoring details to be provided to DNA so that it has all updated information for algorithmic processing. The interface also allows for any controls resulting from algorithmic processing to be transmitted from DNA to D-SCADA for further propagation to devices in the field. All data exchanges in this interface are via Siemens proprietary technology.

2.2.4.3.3 Post-Implementation Operational Issues

Following the standup, integration, and preliminary testing of the D-SCADA (PowerCC) system, numerous post-implementation operational issues needed to be mitigated and considered. These issues included the following:

- Software Updates – Upon installation of the system at KCP&L, efforts were commenced to stabilize the system, perform SAT, and begin operating the system as situational opportunities arose. Throughout this period, numerous system deficiencies were discovered which necessitated fixes to be delivered by the software vendor. Due to the co-mingled architectural nature of the DMS sub-systems, these fixes were delivered and installed as part of several subsequent “builds”. Efforts were initially pursued to deploy updates frequently, but were scaled back due to the complexity of regression testing functionality, completing deployment to all servers and UIs, and then re-establishing stability. Due to the integrated nature of D-SCADA with the DNA applications, several builds were deployed with updates for both capabilities. The updates focused primarily on D-SCADA functionality are listed below:

Build No.	Date	Content
100	5-30-2013	Core DSSE/DSPF stability variances; preliminary HIS configuration
108	8-22-2013	DMS/DERM heartbeat & battery functionality
121	11-27-2013	Comprehensive delivery of all outstanding variances

- Network Model Data Migrations – During initial configuration and build efforts, only a subset of planned, end-state devices and their corresponding points were captured in the data model. This was done to reflect the limited number of deployed devices at configuration inception, but also to limit the complexity of model connectivity while establishing process stability. However, in the preliminary configuration and test environments, many of the attempted data migrations with this limited data set took significant time and effort to implement and stabilize. When the system was transferred to KCP&L, it maintained this subset of devices and due to the known challenges with the data migration process, incremental data migrations were not pursued for some time. This allowed time to complete device deployments in the field as well as setup and conduct numerous additional test data migrations in the lab environment prior to conducting a data migration in the demo environment. In retrospect, the lack of a complete data model was a hindrance requiring certain workarounds, but it was still preferable to the potentially long time periods of environment inaccessibility waiting for the data migration to re-stabilize.
- Field Device Communications Instability – D-SCADA (PowerCC) capabilities are dependent on the quality of SICAM and further downstream field device/substation data. While there were a handful of issues expressly tied to the core D-SCADA capabilities, a majority of issues were due to these other systems and evidenced themselves in D-SCADA. As discussed in greater detail in the SICAM and Tropos build sections, significant effort was put forth to stabilize the communications channels to field devices and ensure robust transmission of real-time data. At times where instability was significant, KCP&L’s ability to have full monitor and control capability was limited and focus was shifted back to SICAM/Tropos stabilization.

2.2.4.3.4 Lessons Learned

Throughout the build and stabilization of the D-SCADA (PowerCC) system, numerous considerations were realized and should be noted for future deployments of this sort. These Lessons Learned are as follows:

- Productized Integration – At the inception of the SGDP, deployment plans were based on the premise of a commercially mature, productized integration of the D-SCADA capabilities with the First Responder (DNA), CAD (I/Dispatcher), DAC (DCADA), and DDC (SICAM) capabilities. However, this productized integration had only been deployed at one other site, which resulted in a larger stabilization effort in KCP&L’s real-world environment. This continued into the post-operational period, where very specific real-world situations conspired to result in system instability situations. Many of these situations could have been avoided had this system been deployed and fully tested in an enterprise operational context prior to implementation at KCP&L.

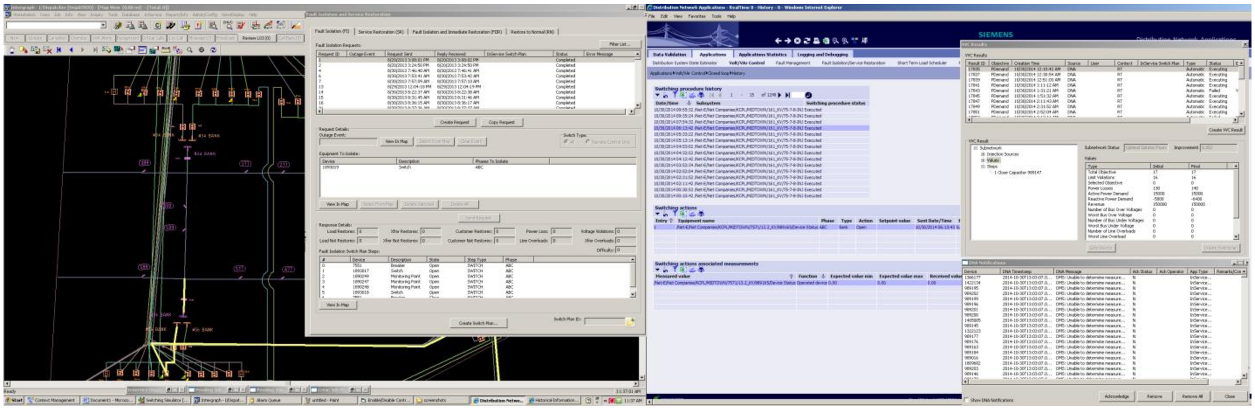
- Systems require greater modularity – As mentioned as a post-operational issue, in many cases when a defect fix was delivered it required a fully compiled build to be installed. The project team came to consider this functionality as “Project-ware” instead of “software” recognizing the high level configuration (verging on customization) that seemed to be required to deliver a fix. It would be envisioned that in a more mature software package, core functions would be deliverable and upgradeable in a more compartmentalized fashion, not requiring a full re-installation of the entire integrated software suite (as was required in the First Responder/D-SCADA implementation).
- Initial Signal List Points Definition – In order to configure the D-SCADA it was necessary to conduct an analysis of points to be captured for each group of devices (e.g. reclosers or cap banks in aggregate). To support First Responder capabilities, a relatively small subset of available points were required. However, considerations from groups such as asset management, engineering, and operations all provided input on how data could be used. As such, the decision was made to have the D-SCADA bring back and manage a large number of points available from every connected. Unfortunately, this volume of data stretched the DDC and field communication technologies to its limits resulting in numerous challenges to ensure stability through the integrated solution. In retrospect, upon discovery that calculated values are less straining on the infrastructure than device communications, one key approach would have been to review the points list and define a subset of points to be calculated in the DDC instead of telemetered.
- Incremental Device Communications Configurations – Where the note above highlights the challenges in defining points applicable to an entire class of field devices (e.g. reclosers or capacitor banks), KCP&L also encountered challenges when establishing communications to a single incremental device being installed. While KCP&L typically knows all of the substation devices that will be in use for the long-term, field devices are deployed in a much more incremental manner. For these incremental field device deployments, the points lists would be defined, but the configurations and corresponding synchronization between systems was highly manual. This required significant coordination and attention to detail, progressively verifying harmonization at each step of the communication pathway to ensure proper spelling of points and cross-mapping DNP names with 61850 names. These efforts to enable substation and field device communications were a notable contrast to the deployment of incremental AMI meters in the field. In the same way that meters would self-identify and propagate communication point capabilities, other distribution devices would benefit from these same capabilities.
- Incremental Network Model Management – In addition to the two previous considerations and as mentioned as a post-operational issue, the installation of a new network data model had significant timing considerations and complexity as it was an all-or-nothing implementation. While this step was vital to allow enabled D-SCADA capabilities to be geospatially displayed on the UI of the OMS component, the team was hesitant about deploying any details about new field devices or circuits because the *entire* network model needed to be re-deployed resulting in significant system downtime to install and re-stabilize. In this context, an incremental network management migration capability would have significantly greater value to a real-time system like the D-SCADA as it would allow the system to maintain its functionality for vast portions of the service territory while only a small, targeted section is having its underlying connectivity details updated.

- ICCP & MQ Connectivity Failure Awareness – As the central device status and control broker in the integrated solution, the D-SCADA heavily uses ICCP and MQ protocols to transmit data to other systems. Independently, any singular interface has relatively high reliability and stability. Unfortunately, given the vast integration of this project, the small instabilities incumbent in each interface conspire with each other and multiply to a general state of frequent communication instability across the entire platform. From a user perspective, the systems only reactively show that end-to-end communications are not working. Upon notification to the project support team, a more detailed investigation is conducted to pinpoint and resolve. However, each instance of communication failure erodes user confidence in the system's ability to reliably perform when it matters. As a result, it has become apparent that as operations become more reliant on highly integrated systems such as this, it is vital to have additional capabilities serving as an IT Network Operations Center. It is envisioned that this function would proactively monitor system communications and ensure consistently higher levels of platform-wide communications and system stability.
- Cross-Platform Time Synchronization – Building on the communication stability challenges mentioned previously, a complicating factor in the diagnosis of issues was the general synchronization of time stamps across all devices and systems. A synchronized time stamp is very important in this type of diagnostic to see when certain signals depart one system and arrive at another. In a context of multiple communications from different devices all being recorded in communications logs, if one system is off by even a couple seconds, then the analysis of different data exchanges is complicated by crisscrossed message streams. The KCP&L time synchronization effort was particularly challenged because different systems used multiple time synch mechanisms: Substation devices from satellite clock, servers derived from network time, field devices synched to SICAM. KCP&L's current enterprise configuration doesn't have a strict requirement for synchronized data as the end-state use of this information is more forgiving in its application. However, this legacy challenge became of greater concern with the advanced applications of the DMS as its algorithms have an increased reliance on timely and synchronized inputs to achieve expected results. Significant effort was put forth to achieve synchronization throughout the demonstration footprint and additional efforts would be required to establish the importance of this throughout KCP&L's culture if it were to be expanded enterprisewide.
- Lab Environment Benefits – For other smart grid system deployments, there have been discussions of the benefits of the integrated lab environment; particularly for the D-SCADA and SICAM systems as KCP&L was able to test end-to-end communications. However, while the lab environment was leveraged for a subset of First Responder tests it was generally not as beneficial for D-SCADA testing. The devices in the lab did not generate the significant quantity of frequently updated data that generally comes from devices in the field. In a production environment, legitimate devices continually provide this data and are continually stressing the system. There were a number of issues in terms of data presentation, data availability, points requirement from devices, time synchronization etc. in the production system. However, in the lab environment, it proved to be challenging to simulate these production issues or compile enough data to truly simulate an entire distribution footprint.

2.2.4.4 First Responder Functions

The Siemens DNA applications provide the DMS First Responder Functions for the combined Intergraph/Siemens DMS as illustrated in Figure 2-57. The First Responder Functions improve the operation of the distribution network by performing real-time analysis, automate control, and optimize the performance of the grid. The following sections provide a summary of the development and configurations that were required to implement and deploy the desired First Responder functionality.

Figure 2-57: KCP&L SmartGrid First Responder User Interface



2.2.4.4.1 Build

KCP&L's First Responder (DNA) implementation efforts were launched by assembling a team of highly skilled individuals that would pursue and support the deployment of these advanced applications. To familiarize themselves with the goals of the project, the team began by reviewing previously created Use Cases to understand new processes and anticipated system functions. In so doing, the team was able to better advocate for how the systems should be configured in later workshops. Unlike some other systems, the First Responder use cases were somewhat higher level as there were relatively few interoperability touch points, but they served as a solid foundation of understanding for newer team members.

In parallel to KCP&L's preliminary use case familiarization efforts, Siemens began establishing its project team to perform the installation. The First Responder core capabilities and interfaces are part of a commercially available, productized software implementation which can be configured to the needs of a given customer. In this context, Siemens began identifying key staff and subject matter experts who would be performing the configuration. As there were relatively few implementations of this product, staff began familiarizing themselves with the key configuration elements required and documenting questions to be answered in preparation of the actual configuration efforts.

2.2.4.4.1.1 Collaborative Design Sessions

After the preliminary familiarization efforts conducted by KCP&L and Siemens, a number of workshops were conducted to ensure a common understanding for what configurations would be performed and how the system would operate. The workshop series started with a discourse addressing various capabilities, modes of operation, and established the context for the system's functionality. As the workshops progressed, a detailed matrix was produced outlining the data points required from each device to support proper algorithmic processing. Further discussions were conducted to define the constructs and requirements from upstream processes to ensure that connectivity in the network model would be sufficient for state estimation and power flow calculations. Based on these discussions, KCP&L had a better understanding of what additional data requirements needed to be compiled and provided as it became available. Siemens left with a better defined set of requirements that they could use to begin their efforts.

2.2.4.4.1.2 System and Interface Configuration

After establishing requirements, configuration considerations, environmental parameters, and a schedule that fully recognizes and accommodates dependencies, then development and configuration efforts could begin in earnest. Siemens consolidated all configuration data provided along with all requirements and began working independently in the vendor environment. Numerous iterations of configuration and isolated testing were performed to establish preliminary functionality. As conditions warranted, Siemens coordinated joint working sessions with Intergraph to work through integration efforts with the CAD system (also co-located in the vendor environment). Additional working sessions were conducted with another Siemens team responsible for the D-SCADA capabilities to ensure proprietary integration with that system was working as expected. Later, as Phases 1 and 2 of the DMS deployment stabilized and the final First Responder configurations were coming together, KCP&L facilitated daily working sessions between KCP&L, Siemens, and Intergraph to ensure a comprehensive and synchronized understanding of the deployment in some of its most nuanced ways. Shared-desktop technology (WebEx) was used extensively to enable these conversations between remote participants by allowing everyone to see the same system function, defect, or configuration process.

2.2.4.4.1.3 Data Model Migration

While numerous configuration efforts were vital pre-requisites to a functional system, a particularly laborious component was the PowerCC IMM model build process discussed previously and illustrated in Figure 2-55. The PowerCC IMM Network Model establishes connectivity between all field devices, their respective circuits, and ultimately the originating substation. Any disconnects or anomalies in this model result in de-energized “islands” of circuitry that confuse the system. Furthermore, the network model leverages signal list configurations and data from Intergraph’s I/Dispatcher to ensure that this virtual representation of the real world yields maximally legitimate algorithmic results. Levering proprietary scripts, I/Dispatcher would extract this key data and compile it into a format which could be transferred and loaded into the First Responder applications.

Initial migration efforts were performed in the vendor environment and numerous iterations were conducted to ensure a stable network model for all devices and all points on each device. The KCP&L project team worked diligently with Siemens to understand the data model propagation process, as well as the behind-the-scenes implications of various configurations. Through much iteration and effort, the data migration process was stabilized, but it consumed far more time than initially planned.

As the network model stabilized and configurations were reviewed in lab and demo environments, increasingly nuanced problems began to evidence themselves. In one instance, reclosers were fully integrated into the model, but the secondary terminals of the current transformer were transposed with respect to the primary and secondary side of the recloser, thus resulting in negative current calculations. This hadn’t previously evidenced itself as a problem in GIS or D-SCADA capabilities given their limited sophistication, but caused significant issues for the DMS DNA applications. In another instance, many of the individual circuit spans in GIS were very short in length, but this proved highly problematic for power flow algorithms that formed the basis of the DMS as they were designed to apply impedance configurations against spans in multiples of 1000 feet. To resolve, the spans needed to be aggregated into “super-spans” so that the algorithms would run as needed.

2.2.4.4.1.4 Training

The KCP&L team learned a tremendous amount during the workshops and joint configuration sessions. However, formalized training was still deemed very important to allow KCP&L users to prepare for testing efforts and ultimately successful operation of the system. Sessions were conducted in-person and numerous training manuals were available to aid the process. In addition, given the previously established successes with WebEx, the project team leveraged this technology in a two-fold manner: 1) all training sessions were broadcast via WebEx which allowed targeted vendor subject matter experts to augment materials presented by the official trainer and 2) training was recorded allowing for ease of referencing back to better understand an explanation or sequence of events. The following table outlines training sessions conducted for First Responder functionality.

Training Course	Dates
Tester Training (Siemens)	08/13/2012 through 08/14/2012
Distribution Network Analyses (Siemens)	10/29/2012 through 11/01/2012
Pre-FAT Demo and Training: State Estimation	December 13, 2012
Pre-FAT Demo and Training: Power Flow	December 20, 2012
Pre-FAT Demo and Training: Volt/VAR Control	January 03, 2013
Pre-FAT Demo and Training: Feeder Load Transfer	January 10, 2013
Pre-FAT Demo and Training: Fault Location & Restoration	January 17, 2013

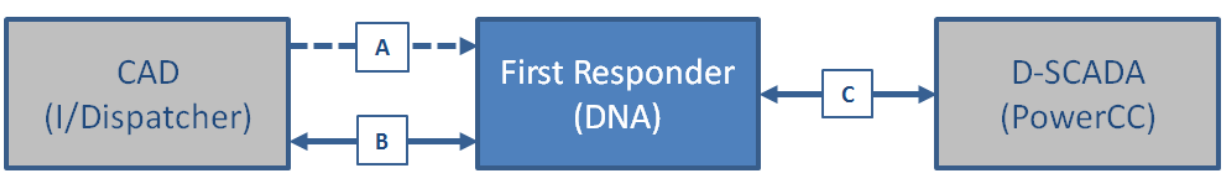
2.2.4.4.1.5 Testing

As outlined above, the more advanced training sessions provided an opportunity for in-depth reviews of functionality to learn how the system is operated. In addition, due to the significantly advanced configuration by this time, the training sessions in the vendor environment also provided an opportunity for KCP&L's testing team to select a subset of tests from the formalized test books to ensure the accuracy of the configuration. Where needed, defects were documented and logged as part of this "Pre-FAT" testing effort. Unlike Phases 1 and 2 which focused on the D-SCADA and required the KCP&L test team to be physically present at the Siemens facility for several weeks, Phase 3 First Responder Factory Acceptance Testing went much smoother. By conducting pre-FAT tests, Siemens was able to align its configurations with an evolved understanding of what KCP&L expected during the formal FAT and had time to update the system in advance. Following execution of all formal FAT tests, KCP&L decided it was ready to migrate the First Responder functionality to its Kansas City-based lab and demo environments in the Spring of 2013. Numerous procedural mechanisms were implemented to stabilize the system and ensure its preliminary integration with the other systems in the environments. SAT commenced opportunistically through Late Spring 2013 and continued with considerable rigor throughout the Summer. All testing efforts resulted in numerous defects being documented where functionality deviated from established requirements. Siemens worked to remediate these defects as soon as they were discovered and continued working to remediate throughout 2013; as variances were fixed, new builds would be compiled and installed to KCP&L's lab and demo environments for re-testing.

2.2.4.4.2 Integration

An overview of First Responder system-to-system interfaces and applicable messages is illustrated in Figure 2-58.

Figure 2-58: KCP&L SmartGrid Demonstration Project First Responder Integration



The First Responder (DNA) capabilities are designed to function independently from the largely integrated system. While it does leverage information from these other systems, much of this information is processed and filtered by the D-SCADA. The integration touch points for the First Responder (DNA) applications are as follows:

A. DNA/CAD Data Model Propagation: As part of the overall network and data model propagation process from GIS to the DMS suite of systems, the key details of the network model are prepared in CAD and then transferred to DNA. This process is performed on an ad-hoc and largely manual basis using Oracle SQL.
B. DNA/CAD UI Integration: A bi-directional interface allowing for DNA algorithmic results and recommendations to be forwarded on for display to the user. The interface also allows user selections and configurations to be passed from the CAD User Interface to DNA. All data exchanges in this interface are via MQ.
C. DNA/D-SCADA Monitor & Control Propagation: A bi-directional interface allowing for D-SCADA point monitoring details to be provided to DNA so that it has all updated information for algorithmic processing. The interface also allows for any controls resulting from algorithmic processing to be transmitted to D-SCADA for further propagation to devices in the field. All data exchanges in this interface are via Siemens proprietary technology.

2.2.4.4.3 Post-Implementation Operational Issues

Following the standup, integration, and preliminary testing of the First Responder (DNA) system, numerous post-implementation operational issues needed to be mitigated and considered. These issues included the following:

- Productized Integration – At inception of the SGDP, deployment plans were based on the premise of a commercially mature, productized integration of the First Responder (DNA) capabilities with the D-SCADA and CAD capabilities. However, this productized integration had only been deployed at one other site, which resulted in a larger stabilization effort in KCP&L's real-world environment. This continued into the post-operational period, where very specific real-world situations conspired to result in system instability situations. Many of these situations could have been avoided had this system been deployed and fully tested in an enterprise operational context prior to implementation at KCP&L.
- Software Updates – Upon installation of the system at KCP&L, efforts were commenced to stabilize the system, perform SAT, and begin operating the system as situational opportunities arose. Throughout this period there were numerous system deficiencies discovered which necessitated fixes to be delivered by the software vendor. Due to the co-mingled architectural nature of the DNA and D-SCADA capabilities, these fixes were delivered and installed as part of several subsequent "builds". Efforts were initially pursued to deploy updates frequently, but were scaled back due to the complexity of regression testing functionality, completing deployment to all servers and UIs, and then re-establishing stability. A list of builds installed by KCP&L is listed below:

Build No.	Date	Content
80	2-19-2013	Initial DNA KCP&L Site Installation
90	3-14-2013	Core D-SCADA variances needed to enable DNA functionality
93	4-17-2013	Core D-SCADA variances needed to enable DNA functionality
100	5-30-2013	Core DSSE/DSPF Stability variances; preliminary HIS configuration
105	7-26-2013	Prioritized DSSE, DSPF, VVC variances
108	8-22-2013	DMS/DERM Heartbeat & Battery functionality
116	10-7-2013	Comprehensive delivery of all DSSE, DSPF, and VVC variances
121	11-27-2013	Comprehensive delivery of all outstanding variances
126	04-22-2014	VVC Closed Loop, Tap Changer configurations and DSSE updates

- Field Device Communications Instability – First Responder (DNA) algorithms are firstly dependent on the quality of downstream SCADA data. As discussed in greater detail in the D-SCADA and particularly the SICAM build sections, significant effort was put forth to stabilize the communications channels to field devices and ensure robust transmission of real-time data. At times where instability was significant, KCP&L's ability to test and operate the First Responder capabilities was limited and focus was shifted back to D-SCADA stabilization.
- DSSE/DSPF Tuning – State estimation (DSSE) and Power Flow (DSPF) algorithms are dependent on a mix of real world SCADA data (recloser, breaker data) as well as historical models (loads per transformer, weather adjustments). While the SCADA data is used directly, in some cases load model data initially used resulted in some algorithmic results being significantly different from real world values (as confirmed by other SCADA or field crew readings). To improve the results, analysis of the algorithms and load models were conducted and tweaked as necessary to achieve more reasonable results.
- Model Connectivity Reverse Flow – The data model migrated from the GIS originally did not have sufficient specificity with respect to power flow and connectivity. The level of detail was sufficient for legacy applications but DNA required greater detail, exact connectivity and directionality of power flow. The connectivity of the lines was to be pristine for the DNA applications to perform correctly. It was also observed that certain recloser configurations were incorrectly assumed by DNA and their connectivity had to be reconfigured in the distribution model for accurate results. As these in adequacies were discovered, the migration went through multiple iterations to ensure correct connectivity and directionality for the distribution model when extracted from the GIS and CAD.
- Simultaneous Reporting of Field Values - The field data coming into the D-SCADA and further utilized by the DNA was communicated on a report by exception basis;. Real time field values change constantly and the deadbands ensured every minute change was not reported thus limiting the stress on the communication and DMS infrastructure. The dead bands though were assigned for types of points (Power, Current, Voltage etc.) as expected but only those specific points whose dead band is violated were reported. DSSE uses all available latest point values in its calculations and as Voltage, Current and Power values were not reported simultaneously, a small error was introduced into these calculations from the onset. DSSE Results are additionally processed and analyzed by other DNA and this error could be magnified in those cases. This could be avoided by reporting a set of points whenever a point's deadband is violated rather than just the one specific point.
- Super-spans, Conductor Impedances – The distribution data model extracted from the GIS contained a large number of line spans, nodes and poles which were substantially more than a typical transmission model. In the model a line section between two poles was a single span and generally a line section between two nodes consisted of several spans. Each of these line spans were assigned specific attributes in terms of type, length etc. The impedances were calculated using standard impedances values which are generally calculated on a per mile basis and were not very accurate for smaller lengths. This caused the impedance for smaller spans to be calculated as zero and subsequently larger lines composed of several smaller spans also had zero impedance. This necessitated an additional step for creating super-spans in the DMS model where several smaller spans between two nodes were integrated into a single larger super-span. This resolved problems at the DNA level and but super-spans existed only in the DMS causing synchronization issues with the other systems such as CAD and DERM. An appropriate solution would involve high accuracy impedance values or a different methodology of converting the model from the GIS and introducing super-spans at the CAD level.

- Modelling Issues – The load/system models used by CAD and DNA required constant modification and tuning to be usable for all DNA applications and functions. Here are a list of some of the concerns and solutions in hindsight.
  - Single Model across all systems - The model in each system such as the D-SCADA, DERM and CAD had critical differences causing issues all along the implementation phase. For instance, super-spans were present only in the D-SCADA model, CAD contained secondary transformers but these were absent on D-SCADA model. These differences created synchronization issues which could have been avoided by using a single data model across the different systems.
  - Seasonal Loads – The seasonal load data used to model the loads were not very accurate and based of peak load models causing DSSE to constantly attempt to tune the load model and never reach a stable load model that could be used to predict future system conditions
  - Substation HV Data availability – The DSSE application utilized the transmission voltage at the source as the major voltage input and derived the remainder of the voltages across the distribution system. VVC further used these as input for its internal calculations over several iterations to generate its results. As substation transformer high side voltages were not available, additional configurations were done to calculate them based of the low side voltages and the transformer tap position/ratio. DSSE should make additional use of various other telemetered voltage. Modelling of HV side of transformer or inclusion of HV data would have reduced the need for additional configurations.

2.2.4.4.4 Lessons Learned

Throughout the build and stabilization of the First Responder (DNA) system, numerous considerations were realized and should be noted for future deployments of this sort. These Lessons Learned are as follows:

- Systems require greater modularity – As mentioned as a post-operational issue, in many cases when a defect fix was delivered it required a fully compiled build to be installed. The project team came to consider this functionality as “Project-ware” instead of “software” recognizing the high level customization that seemed to be required to deliver a fix. It would be envisioned that in a more mature software package, core functions would be deliverable and upgradeable in a more compartmentalized fashion not requiring a full re-installation of the entire integrated software suite (as was required in the First Responder/D-SCADA implementation).
- Incremental Network Model Management – As mentioned as a post-operational issue, the installation of a new network data model had significant timing considerations and complexity as it was an all-or-nothing implementation. The team was hesitant about deploying any details about new field devices or circuits because the *entire* network model needed to be re-deployed. In this context, an incremental network management migration would have significantly greater value to a real-time system like the First Responder capabilities as it would allow the system to maintain its functionality for vast segments of the service territory while only a small, targeted section is having its underlying connectivity details updated.

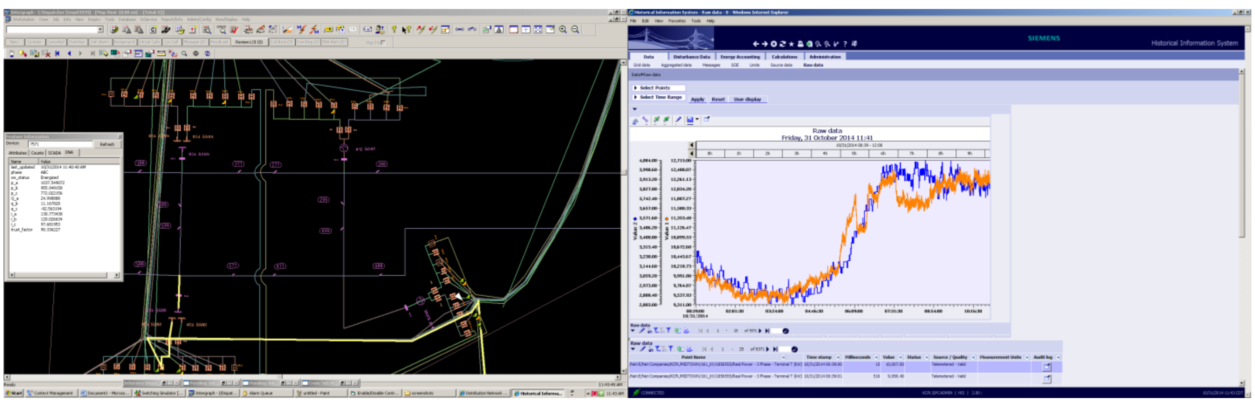
- Lab Environment Benefits – For other smart grid system deployments, there have been discussions of the benefits of the integrated lab environment; particularly for the D-SCADA and SICAM systems as KCP&L was able to test end-to-end communications. However, while the lab environment was leveraged for a subset of First Responder tests, it was generally not as beneficial for a majority of DNA testing. Specifically, the First Responder applications require a significant quantity of frequently updated data from devices in the field. In a production environment, legitimate devices continually provide this data. However, in the lab environment, it proved to be challenging to simulate or compile enough data to truly simulate an entire distribution footprint.
- Telepresence Benefits – Collaboration between KCP&L and its vendor partner were challenged due to geographic dispersion. A vital mitigation strategy was extensive use of shared-desktop technology (WebEx) to allow remote access to systems and support mutually-viewed sessions for trouble analysis. Of particular note, KCP&L was able to better prepare for its Phase 3 First Responder FAT by conducting numerous weekly sessions to verify the basic anticipated functionality. In so doing, travel was minimized and team members were able to participate very effectively from their respective local offices. Furthermore, ad-hoc training sessions were able to be conducted via this technology which enabled the vendor’s subject matter experts to engage and explain concepts more efficiently than traditional methods. Frequently, KCP&L was able to record these digital sessions and found them to be incredibly valuable reference material upon questions arising or to transition new team members to the project. The recordings proved so valuable, that in the future, KCP&L would be interested to include language in vendor contracts to establish a baseline understanding that these assets will be created through the course of project pursuits.
- Application and Results Visualization – The DNA applications and results are available to the user in several methods such as a separate web UI, dialog boxes within the map display or as small hover boxes over specific devices; the detail varied and drastically reduced from the web UI to hover boxes. These options present all the required data in some form but require the user to deviate from their normal operations to capture and process the data. This also reduces the effectiveness of the application as the operator is always searching for application information/results and trying to put them in the system perspective. As a result and operator is prone to ignore these applications in crunch situations (Major outages, storms etc.) where they are actually the most effective. This could be avoided if the applications and results were seamlessly integrated with the legacy data and day to day activities of the operator thus providing additional information and situational awareness without major deviation from normal operations.
- Study Modes (Forecast the future) – The Study mode capability was similar to the real time context UI but was limited in terms of functionality. The Study mode was not very user friendly and considerable time had to be spent each time to stabilize a study mode. Whereas certain reduction in DNA functionality was expected, the issues faced in starting study cases, saving, restoring study cases and validating the results reduced the efficiency of the process. The seasonal load model also has to be highly accurate and continually tuned by DNA to achieve required accuracy when predicting the future. The load model was constantly tuned and was not stable enough to predict the future. The Study mode was used for specific applications but substantial time was lost in stabilizing the application and tuning the parameters for correct results.

- Distributed Resources Modeled as Negative Loads – The distributed resources were all modelled as negative loads. The integration of distributed resources at the distribution grid level requires that they be accurately represented in the electrical model to achieve more accurate power flow and other advanced distribution network analysis applications
- Secondary Transformers – The model used by DNA was generated only up to the primary of the LV transformers and did not include the low voltage system. This greatly reduced the granularity of the model and the effectiveness of applications such as DSSE, VVC and STLS as secondary losses and secondary voltage drops were completely ignored. This limited the accuracy of VVC in particular, necessitating additional monitoring on the LV side and customer meters to ensure that the values are within limits. The feedback and self-healing capacity was greatly diminished as a result. It was observed that secondary losses and voltage drops changed drastically with loading conditions thereby the application also had to be constantly tuned by the user to get optimum results. Availability of secondary transformers and LV data in the model would have substantially reduced the monitoring needs and the time spent to tune the applications.

2.2.4.5 Historical Information System

The Siemens HIS component provides a reliable achieve of historical real-time D-SCADA data. The HIS user interface is illustrated in Figure 2-59. The following sections provide a summary of the development and configurations that were required to implement and deploy the desired HIS functionality.

Figure 2-59: KCP&L SmartGrid HIS User Interface



2.2.4.5.1 Build

KCP&L's DMS Historian was not initially included in the original scope for the KCP&L SGDP. However, as the project progressed, investigations were conducted on the in-scope systems and the team determined that default archival capabilities of the DMS systems would be insufficient to produce the analytics required for the later stages of this reporting document. Therefore, a dedicated Historian Application was pursued as it became clear that an archival technology would be required for troubleshooting and reporting in the future.

2.2.4.5.1.1 Design

Internal discussions were conducted to determine available alternatives and the team quickly narrowed-in on a bolt-on module available for Siemen's PowerCC product known as the Historical Information System module. A remote demonstration of HIS capabilities was conducted in Winter 2013 to understand the functionality and known limitations of the system. The team quickly determined that this capability was best for KCP&L's needs and outlined the high level requirements – mainly that the HIS would be configured to store all the data points for all device types. With the goal of reconstructing a particular day's operations, the requirements were later flushed out to include the following real-time information:

- All Analog values
- All Accumulator values
- All Digital values (status information, device operations)
- All Tap positions
- All Messages (alarms, user logons, system status, connection, power flow)

2.2.4.5.1.2 Configuration

Siemens pursued preliminary configurations of HIS in the vendor environments to enable capturing of analogs, accumulators, and digitals. Throughout, there were numerous questions that came up where KCP&L provided guidance. Of particular note, the technical environment resulted in the largest number of questions regarding database sizing, integration with the server cluster, and appropriate database privileges configurations allowing for data recording.

2.2.4.5.1.3 Training

The KCP&L team learned a tremendous amount during the preliminary demonstration session. However, formalized training was still deemed very important to allow KCP&L users to prepare for formalized testing efforts and ultimately successful operation of the system. A session was conducted via WebEx and numerous training manuals were available to aid the process. In addition, given the previously established successes with WebEx on other systems, the project team leveraged this technology to record the session for ease of referencing back to better understand an explanation or sequence of events. While doing so, some preliminary defects were identified as applicable to the KCP&L configuration. The following table outlines training sessions conducted for HIS functionality.

Training Course	Dates
HIS Functionality Demonstration (Siemens)	01/24/2013
HIS Tester Training and Operation (Siemens)	10/07/2013

2.2.4.5.1.4 Implementation

Unlike other systems of the DMS which were tested in vendor environments prior to implementation in demo environments, for expediency and minimal anticipated risks, the HIS was deployed to KCP&L systems when deemed ready by Siemens. A code release containing only incremental HIS capabilities was provided and installed. Numerous data base changes were required and implemented to ensure the new functions worked as expected. Siemens worked closely with KCP&L's database administrators to ensure these configurations were implemented properly. Final configuration changes were implemented to enable the new HIS module to commence archival capabilities.

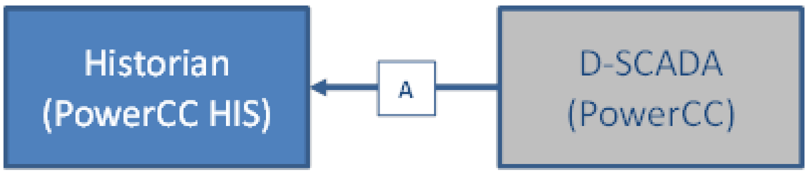
2.2.4.5.1.5 Testing

As with other systems, Siemens provided a standard test book for review by the test team. As the KCP&L test team went through the test book, tests were added and removed as necessary to ensure appropriate coverage and confidence in HIS archival capabilities. Based on an understanding of these functions, the previously mentioned training was pursued with a supplemental agenda outlining certain functions which KCP&L requested to be demonstrated during the session. With the necessary tools to autonomously perform testing, the KCP&L team pursued a more formalized and rigorous testing effort by executing the test scripts documented in the test book. As identified, defects were documented in a tool provided by Siemens and tracked to resolution.

2.2.4.5.2 Integration

An overview of HIS system-to-system interfaces and applicable messages is illustrated in Figure 2-60.

Figure 2-60: KCP&L SmartGrid Demonstration Project HIS Integration



The HIS functions enable a significant amount of KCP&L's reporting capabilities. In particular, its integration with D-SCADA is vital to ensure that all real-time data is syphoned and archived as required. The integration touch point for the HIS is as follows:

A. D-SCADA/HIS Data Propagation: "Real-Time" data points from all devices are sent from D-SCADA (PowerCC) to HIS for data collection and storage. All data exchanges in this interface are automatically performed using Oracle SQL.

2.2.4.5.3 Post-Implementation Operational Issues

Following the standup, integration, and preliminary testing of the HIS system, few Post-Implementation Operational Issues needed to be mitigated and considered. These issues included the following:

- **Software Updates** – Upon installation of the system at KCP&L, efforts were commenced to stabilize the system, perform SAT, and begin operating the system as situational opportunities arose. Throughout this period, several system deficiencies were discovered which necessitated fixes to be delivered by the software vendor. Some of these were corrected by changing some configurations. However, due to the co-mingled architectural nature of the DMS sub-systems, some other fixes were delivered and installed as part of several subsequent "builds". A list of builds including HIS functional for KCP&L is listed below:

Build No.	Date	Content
100	5-30-2013	Preliminary HIS configuration (and other DMS functions)
121	11-27-2013	Misc. HIS defect fixes (and other DMS functions)

- Integrated System Stabilization – While not an issue of the HIS directly, other systems in the DMS suite did experience some issues achieving stability. To this end, the HIS was very helpful by providing significantly expanded logging of data and message types. In turn, this was used to help better understand the context of real-time network traffic as a potential basis for underlying stability issues.

2.2.4.5.4 Lessons Learned

Throughout the build and stabilization of the HIS system, numerous considerations were realized and should be noted for future deployments of this sort. These Lessons Learned are as follows:

- Archival Capacity – KCP&L scaled its archival database to 300GB, but in an enterprise deployment, significantly larger capabilities could easily be required. The archive was based on a limited deployment of substation and Distribution Automation (DA) devices (approx. 120 total). Each device had approximately 50-100 points. Each point was recorded to the archive upon status/value change or no more frequently than once every four seconds (whichever occurred less frequently). KCP&L is currently on track to fill this archival DB after one year of recording. Based on configurations for how much data is captured, and requirements for maintained capabilities, business processes for later consumption of this historical data should be contemplated to size appropriately.
- Data Revisions – The HIS offers the capability to revise data that has been previously recorded; but care should be taken when granting permissions to do so. Depending on system usage, it may or may not be mission critical to be able to modify historic real-time DMS/D-SCADA data. Testing at KCP&L showed that these capabilities could have benefited from additional access restrictions.
- Subsequent Build Coordination – Deployment of incremental software compilations (or builds) must be coordinated with the project team and Siemens to ensure timely delivery and minimal impact to the system.
- Data Extraction Capacity – The HIS had limited data extraction and display capabilities. The HIS could only extract and display a couple of days' worth of active power data active power was reported approximately every two seconds. This proved a major drawback as data had to be individually extracted for each day and processed separately. The HIS with more robust extraction capability would have saved substantial extraction time and the time spent on accumulating and processing the data. The lack of weighted averages mentioned below also exasperated the situation as averages would have drastically reduced the amount of data to be extracted.
- Limited Data Manipulation – The HIS is capable of calculating averages and aggregating reported data but these require data to be reported only at regular intervals across the system. The data coming into the HIS was on a report by exception basis and any average would have to be calculated by taking the time into consideration. The average and aggregate functions were thus not very accurate and could not be used to extract and aggregate data. A weighted average function in the HIS would have greatly reduced data extraction and manipulation times as the average data would be substantially smaller than raw data.

2.2.4.6 ADA Field Area Network

The Tropos wireless IP mesh was deployed as the foundation for the ADA Field Area Network (FAN). The ADA FAN provides the monitoring and control communications infrastructure to devices outside the substation. The following sections provide a summary of the development and configurations that were required to implement and deploy the desired ADA FAN functionality.

2.2.4.6.1 Build

Work on the Tropos network began in February 2012. As the KCP&L team began getting comfortable with the technology, several Tropos engineers came on site to perform a field survey of the project territory. With the help of KCP&L engineers, they determined the acceptable mounting assets for the network gateways and the base mesh nodes. They also spent some time training the KCP&L field crews on the mounting and installation process for both types of routers.

From a networking perspective, Tropos also worked with KCP&L's Network Services group to determine a strategy for integrating this new RF mesh network into KCP&L's IP infrastructure. They chose not to add the Tropos network to the KCP&L corporate network; rather, it is located within the new, isolated smart grid network that Network Services designed and implemented as part of the SGDP. Tropos worked with Network Services to consider the total quantity of nodes for the smart grid implementation, and based on this, they crafted the initial design. This design called for two take-out points: one at Midtown Substation (to backhaul the south half of the network) and the other from a tower at 801 Charlotte (to backhaul the north half of the network). Network Services reserved IP address space for both the Tropos mesh network itself, as well as the wired client interfaces. This translated to two IP addresses for each 1310 router (1 wireless IP for the 2.4GHz radio and 1 wired interface to the connected field device) and three IP addresses for each 6320 router (same as the 1310, plus a wireless interface for the 5.8GHz radio).

Another initial design discussion revolved around the IP-enabled field devices and how to terminate all of the associated VPN tunnels within the smart grid network. In the end, the Network Services team chose to use a dedicated Cisco router to terminate all the VPN tunnels that are used for communication to and from the IP devices—the FCIs, reclosers, and RTAC. The capacitor banks differed – the serial devices don't utilize VPN tunnels for communications.

2.2.4.6.1.1 Lab Implementation

The next step in the ADA network implementation was to set up a lab instance of the Tropos mesh network. KCP&L wanted to test out the capabilities of the network in a controlled environment, so routers, gateways, and field devices were set up in a lab at KCP&L. The lab was set up to mimic the production environment as closely as possible. As such, Network Services used this environment extensively to ensure that their designs and configurations would work as expected with the new technology. In its final state, the lab consists of the following routers and field devices:

- (1) 6320 gateway
- (2) 1310 routers connected to capacitor bank controllers
- (1) 1310 router connected to an FCI receiver
- (1) 1310 router connected to an RTAC
- (1) 1310 router connected to a recloser controller

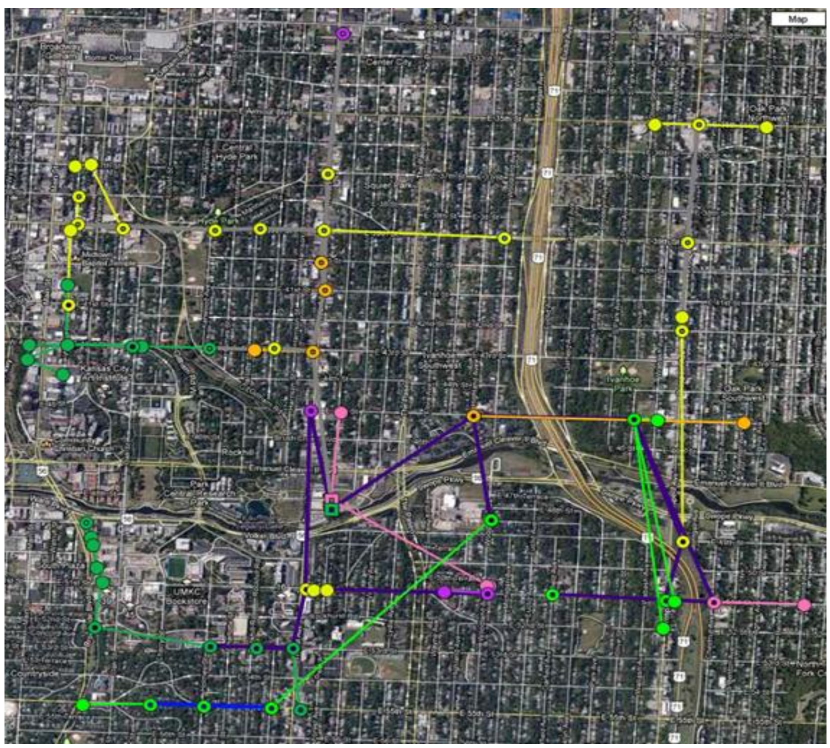
2.2.4.6.1.2 Base Mesh Deployment

After getting comfortable with the lab network and determining the over-arching network design, KCP&L field crews began deploying the base mesh 6320 and 1310 devices in the field. The key elements of the base mesh included:

- Tropos Infrastructure Gateways (6320s) - two at 801 Charlotte and two at Midtown Substation
- Tropos Infrastructure Nodes (6320s)
- Tropos Edge Routers (1310s)

After completing a first pass at the base mesh, Tropos and KCP&L worked together to optimize the network. As a result, several nodes were relocated, and several were added to the network. These changes greatly improved network performance, and at the completion of the base mesh build-out in December 2012, all nodes had at least a 92% ping success rate. The base mesh network is shown below in Figure 2-61 with each RF communication channel represented in a different color.

Figure 2-61: KCP&L Base Mesh Network



2.2.4.6.1.3 Field Device and Edge Router Deployment

After all of the Tropos base mesh nodes were deployed, the remainder of the field devices were installed, along with their respective Tropos routers. KCP&L deployed most of the capacitor banks first, mostly because the controllers were available, and the capacitors were already in the network model. The SEL 651R was a new device, and it wasn't readily available for installation in the production environment at the beginning of 2013. Once they became available, the reclosers were deployed on the highly automated smart grid feeders that were to be used for testing – feeders 7551 and 7561. The FCIs were deployed on these feeders next, finalizing the field device deployments on the prioritized feeders so that the team could start to test the First Responder functions.

After deploying the field devices to the prioritized feeders, KCP&L worked on the reclosers for the non-prioritized feeders. The production RTAC and its associated router were installed at the Midtown Substation battery control enclosure during the first quarter of 2013. The FCIs were deployed to the production network last.

Upon deployment of the routers and field devices, point-to-point checkouts were conducted.

Normally, KCP&L would not have utilized reclosers to perform all of these functions; rather, they would have used a combination of switches and reclosers. For this project, however, they decided to use reclosers for isolation, mid-circuit, and tie functions. This decision was made for two reasons. First, the cost difference between reclosers and switches has decreased dramatically. There isn't as much incentive to utilize switches even when full recloser functionality isn't required. Second, KCP&L wanted to test the use of field device profiles. The same device will be used to perform three separate functions, and this will be implemented through the use of DNP profiles.

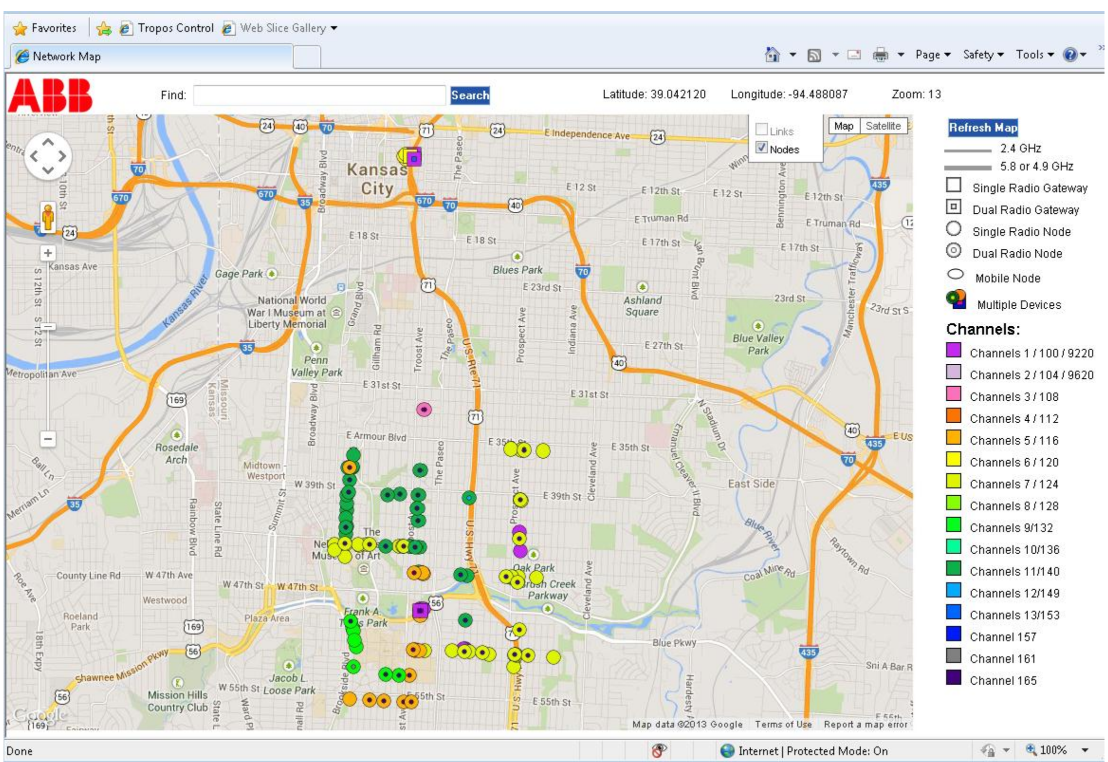
The field device and router deployment was finalized in Q4 of 2013. Upon completion of the ADA deployment, the field devices described in Table 2-12 were installed for the SGDP.

Table 2-12: Field Devices

Field Device	Vendor/Model	Quantity
Capacitor bank controllers	S&C IntelliCAP PLUS	29
Fault circuit indicator receivers	Horstmann	12
Recloser controllers	SEL 651R	20
Grid-connected battery controller	SEL 3530-4	1

The final deployed Tropos network map is shown below in Figure 2-62. The various colors on the map represent different communications channels that the routers are currently communicating over.

Figure 2-62: KCP&L Final Deployed Mesh Network



2.2.4.6.1.4 Capacitor Bank Deployment Specifics

The capacitor banks themselves were GE Capacitor Racks, and they had been in use prior to the SGDP. The controllers were new for the project, and KCP&L chose to use the S&C IntelliCAP Plus.

The pictures below detail the capacitor bank installations. The picture on left shows the controller within its enclosure. The picture on the right shows the actual field installation. The controller enclosure is shown in the bottom right corner of the picture (about 8-10 feet above the ground). The Tropos 1310 router is mounted on the arm that extends out from the pole about 2/3 of the way up. The actual cap bank itself is located near the top of the pole.

The capacitor bank is the only field device in the SGDP that utilizes serial communication to and from the Tropos 1310 router. The interface between the Tropos router and the DDC uses DNP3 for communications.

Figure 2-63: Typical Capacitor Bank Installation

2.2.4.6.1.5 Fault Current Indicator Deployment Specifics

The fault current indicators used in the SGDP were Horstmann Smart Navigators, and the controllers for the sets of FCIs were Horstmann Smart Receivers. The FCIs provide magnitude of fault and fault direction. Each receiver can communicate with up to twelve Navigators. The receiver utilizes 2.4GHz RF to communicate with FCIs, and the Tropos router automatically adjusts what channel it is communicating on to avoid interference. The range of communication between the receiver and its associated FCIs is approximately 100 feet line-of-sight.

The pictures below detail the FCI installations. The picture on left shows one of the Smart Navigators, the picture in the middle shows the inside of the Smart Receiver enclosure, and the picture on the right shows the actual field installation. The receiver is shown attached to the pole (about 8-10 feet above the ground), the Tropos 1310 router is mounted on the arm that extends out from the pole about 2/3 of the way up, and one of the Smart Navigators is attached to the distribution line.

The FCI is an IP-enabled device and it communicates to the DDC with DNP3.

Figure 2-64: Typical Fault Current Indicator Installation

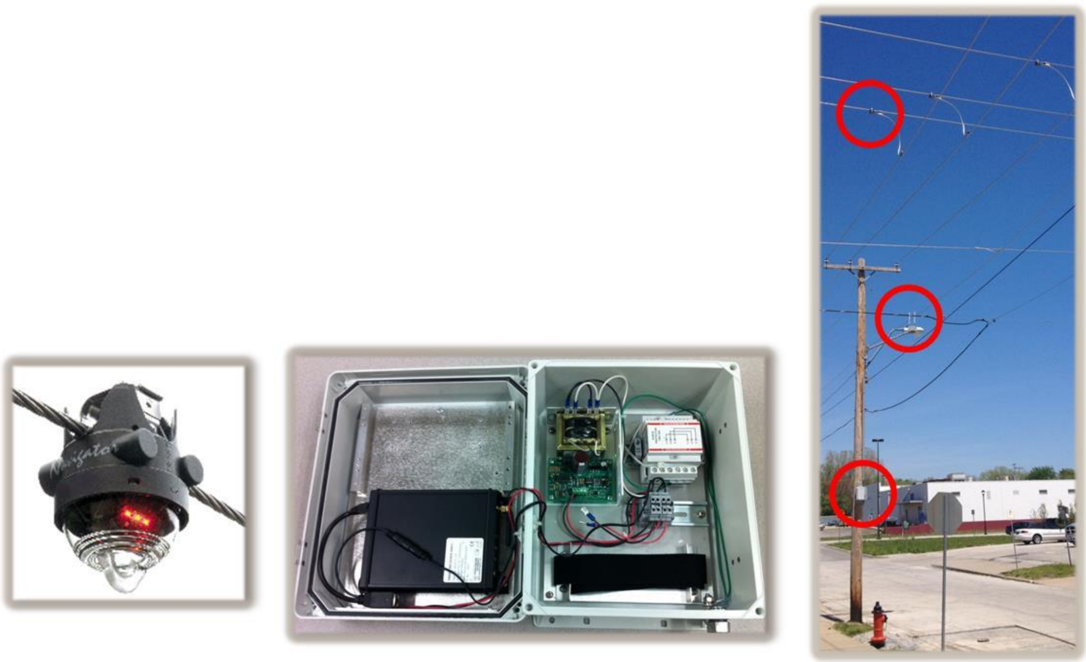


Figure 2-65: Typical Recloser Installation

2.2.4.6.1.6 Recloser Deployment Specifics

KCP&L used two different types of reclosers for the SGDP: the G&W Viper – ST Triple Option Vacuum, and the Siemens SDR Triple-Single Vacuum. The recloser controller was the SEL 651R-2. The SEL 651R-2 was chosen because it can support 61850-MMS messages. KCP&L ultimately decided to utilize DNP3 in order to retain consistency throughout the DA deployment; however, the 651R-2 enables KCP&L to demonstrate MMS messaging down the road.

The pictures in Figure 2-65 above detail the recloser installation. The picture on the left shows the controller inside its enclosure with the battery backup. The picture on the right shows the actual field installation. The controller enclosure is mounted about 8-10 feet above the ground. The Tropos 1310 router is mounted on the arm that extends out from the pole about 2/3 of the way up. The recloser itself is near that top of the picture.

2.2.4.6.1.7 Battery RTAC Deployment Specifics

For the grid-connected battery, KCP&L used an Exergonix DESS CS1000. The inverter was an S&C SMS, and the controller was an SEL 3530-4, also known as an RTAC (Real Time Automation Controller). The RTAC was added between the substation controller and the S&C SMS because it supports IP communication and both 61850-MMS messages and DNP3 protocol. The RTAC also enabled the battery to be utilized as a field device. In a real-world application, a battery would most likely reside in a rural location. By utilizing the DA network for communication, it allows KCP&L to demonstrate this architecture. The RTAC also allowed for dynamic operation of the battery, since the inverter can only operate based upon static parameters. Lastly, the RTAC enabled development of battery controller algorithms.

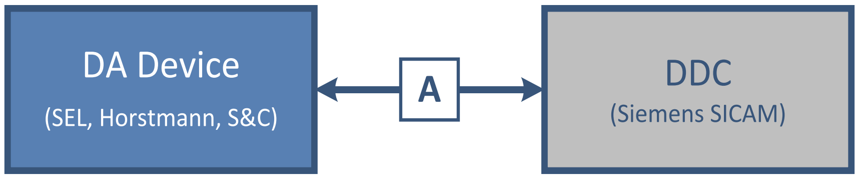
The pictures below show the DESS (top) and the RTAC (bottom).

Figure 2-66: Battery Installation

2.2.4.6.2 Integration

The Distribution Automation Field Area Network isn't a "system" per se, but it does enable communications between field devices the data concentrator, the SICAM. An overview of the DA device communications and applicable messages is illustrated in Figure 2-67.

Figure 2-67: KCP&L SmartGrid Demonstration Project DA Integration



The integration touch points for the ADA FAN are as follows:

A. DDC/Field Devices Monitor and Control Propagation: A bi-directional interface allowing for field device point monitoring details to be provided by the field device (capacitor bank, fault current indicator, recloser, or battery) to the DDC so that it has all updated field device information for use by the DDC and other upstream systems. This communication occurs in real time as device status changes, and it also occurs on regular intervals via predefined integrity polls initiated by the DDC. The interface also allows for any controls resulting from DDC functionality to be transmitted to the field device. All data exchanges in this interface are transmitted via the Tropos network using DNP3.0.

2.2.4.6.3 Post-Implementation Operational Issues

Following the construction, start-up, and preliminary testing of the ADA FAN, numerous post-implementation operational issues needed to be mitigated and considered. These issues are as follows:

- Tropos Firmware Updates – After the initial deployment of the Tropos routers, KCP&L had to conduct several firmware updates. In general, when a new version of firmware came out, Tropos alerted KCP&L and explained the modifications in the updated version. Next, the Network Services team tested out the firmware update in the lab to make sure that everything went smoothly. After a thorough test out, the firmware was deployed to all of the production routers. This process was fairly simple, as the new firmware can be pushed to all of the devices simultaneously from the Tropos Control GUI. KCP&L performed the following firmware updates throughout the duration of the project:

Date	Firmware Version
September 11, 2012	7.7.1.5
October 26, 2012	7.9.1.1
January 29, 2013	7.9.1.2
July 01, 2013	8.0.1.0
June 25, 2014	8.0.4.2

  Although the push to the routers usually went fairly smoothly, KCP&L did have some trouble getting all the devices to re-mesh with the network. A handful of devices required local power cycling of the device in order to re-mesh after each firmware update. This hasn't been a major issue, but it would be more significant in a full-scale deployment.

- VPN Tunnels – Occasionally, the router VPN tunnels dropped and they didn't automatically get rebuilt. The VPN tunnels are expected to go down occasionally, but they should rebuild themselves—after a certain amount of time, the radio is supposed to request to build the VPN tunnel again. Originally, it wasn't clear whether this problem was due to something on the Tropos side or something on the Cisco router (the router that terminates the VPN connection). Eventually the issue was determined to be a Tropos problem, and it was resolved with the last firmware update.

- Poor Signal Quality – The most common post-operational issue that the KCP&L team has dealt with is poor router signal quality. This is due to all kinds of environmental factors, such as varying tree cover during different seasons, noise on the network from non-Tropos communications, or weather events. In addition to these environmental variables, the growing Tropos network also had a significant impact on the signal quality of each router. As field devices were deployed and their associated Tropos nodes were added to the network, KCP&L was able to watch to see how the network paths changed and updated themselves to adjust to different routing options.

  Although the Tropos routing algorithms are proprietary, there were certain strategies that Tropos helped the KCP&L team to implement in order to address specific signal quality issues. Some examples of these strategies include:

  - Forcing routers to specific channels temporarily to force certain better quality paths
  - Configuring 6320 routers to choose the 5.8GHz frequency instead of the 2.4GHz frequency in order to boost stability of the base mesh
  - Moving base mesh nodes to "better" locations in order to provide better signal quality or to reduce the hop count
  - Swapping out 1310 routers with 6320 routers in order to extend the 5.8GHz frequency to a corner area of the Tropos network

- Power Supplies – Another post-operational issue that KCP&L encountered had to do with power to the Tropos routers. The routers attached to capacitor banks and FCIs are all powered off the field device controller, so they didn't require an external power supply to the radios. The base mesh nodes all utilize Power over Ethernet (PoE) devices to supply the input voltage. The substation battery also uses a PoE device, as the RTAC (which is used for battery control) can't power the associated Tropos router. The reclosers were originally deployed without external power supplies, but KCP&L started to notice issues with these devices. Upon further investigation, they realized that the voltage supplied by the recloser controllers was on the low edge of what the Tropos router would tolerate. As a result, KCP&L chose to deploy PoEs for the recloser routers, and this resolved the problems.

  On-Going Monitoring and Troubleshooting – The largest post-operational work that KCP&L has conducted in relation to the DA network is general monitoring and troubleshooting. As the router and field device deployment progressed, KCP&L started doing daily checks of the SICAM. This would alert the team if interfaces to particular devices were problematic, and then the team would use Tropos Control to further investigate the connections to these devices. The daily SICAM checks provided the team with an instantaneous snapshot of the status of connections from the SICAM to all field devices, but they were only useful if there was an issue at the particular moment when the user logged into the SICAM. As a result of this shortcoming, KCP&L also found it necessary to do weekly in-depth checks of each router. The Tropos Control router checks provided a history of each router health, and they included logging each router's uptime, the current path quality, and the number of hops from that router. The router uptime helped the team to discover any issues that might have been missed during the daily SICAM checks. Investigating the problem nodes in this manner helped KCP&L to uncover router reboots that may have occurred over the past week. These reboots were traced back to power issues (leading to the deployment of PoEs on the recloser routers), mechanical issues, or wiring issues with the relays themselves.

- Gateway Placement - The last post-operational issue pertaining to the Tropos network involved the gateways. In the original design, KCP&L deployed redundant gateways at the northern end of the network and at the southern end of the network. Unfortunately the northern location was dependent on a point-to-point link between the northernmost base mesh node and the gateway location, and there were a lot of noise issues there due to other devices installed at that tower. The noise caused significant interference issues with the point-to-point link, so KCP&L ended up disabling the gateway components of the northern 6320s gateways. This basically disabled the capability for downstream nodes to mesh with these 6320s, so all router traffic was forced to the southern gateway. This is obviously not an ideal setup, but it has worked sufficiently well for the small geographic area of the SGDP, and KCP&L still has redundant gateways at the south location. For a larger deployment, KCP&L would definitely need multiple gateway locations.

2.2.4.6.4 Lessons Learned

Throughout the build and stabilization of the ADA network, numerous considerations were realized and should be noted for future deployments of this sort. These Lessons Learned are as follows:

- Optimal Use of Mesh Network – Although the mesh network provided a high speed network for the DA devices, it wasn’t utilized to its full potential. A mesh network functions best when its size allows for multiple paths to any node. Unfortunately, KCP&L’s mesh network was too small (in geographic span) to realize the benefits of multiple paths. Thus, when one node went down, there weren’t multiple backup paths. The mesh network would work better for a larger geographic area where high speed communications are needed.
- Maximize Takeout Points – One of the major lessons learned on this component of the project was that takeout points are extremely important. In order for the mesh network to perform as well as possible, it is critical to have as many takeout points as possible. This will decrease the hop count and decrease the burden on any single set of gateways.
- Communications Tuning – Despite the proprietary nature of most mesh network routing algorithms, there are always ways to do manual intervention to prioritize certain parameters over others. KCP&L worked with Tropos on several occasions to overcome certain features of their routing algorithm that were problematic in the SGDP implementation.
- Data Concentrator Communications – One of the major themes of the DA deployment was that the use of wireless network technology for DA means that the data concentrator needs to support less than ideal communications quality. Although many data concentrators claim to handle wireless communications, most on the market today were built to work with wired communications. Latency and timing are two major factors that will not mimic the traditional wired solution, and these cannot break the concentrator.
- Router Power Requirements – KCP&L learned about the importance of carefully thinking through all the details associated with each router deployment, especially pertaining to router power. Being on the edge of the voltage requirements was problematic for KCP&L, and the team ended up adding power supplies in order to boost input voltage to necessary levels for the routers.

2.2.5 SmartGeneration

The SmartGeneration subproject deployed a state-of-the art DERM system to manage several types of distributed energy resources including DR load curtailment programs, grid connected battery energy storage system, grid connected distributed solar generation, and electric vehicle charging stations. The following subsections summarize these SmartGeneration component deployments.

2.2.5.1 Distributed Energy Resource Management

The OATI WebSmartEnergy Distributed Energy Management Solution was implemented to provide the DERM project component. The DERM system stores and manages all information pertaining to demand response and distributed energy resource programs and assets. The DERM system also communicates DR and DER control events to various "control authorities" that manage particular types of resources. The following sections provide a summary of the development and configurations that were required to implement and deploy the desired DERM functionality.

2.2.5.1.1 Build

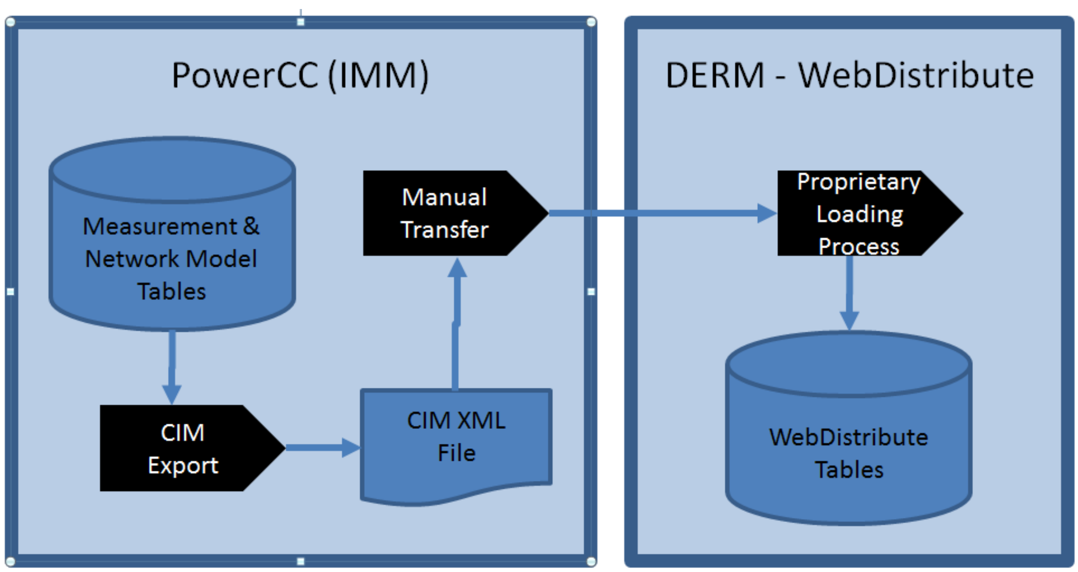
The DERM implementation began in 2011. The first step in this process was to familiarize KCP&L personnel with the capabilities of the system. OATI project members came to KCP&L for a workshop where they demonstrated the overall system, and then they walked through the components planned for the KCP&L project.

2.2.5.1.1.1 Network Model Migration and Synchronization

The kickoff workshops quickly established the need for foundational network model data and electrical infrastructure data upon which base functionality would be configured. The DERM system must synchronize its data model with the D-SCADA to make accurate calculations of its own. As later integration capabilities were enabled, this data would become more crucial.

The DMS to DERM network model migration process is illustrated in Figure 2-68. The network connectivity model and associated loads were exported from the Siemens PowerCC IMM data base using the CIM Export process to create a CIM RDF XML file. The CIM RDF file is made available for manual file transfer to OATI, typically via email on an ad-hoc basis. OATI then uses a proprietary CIM RDF loader tool to process the file and load the WebDistribute network model tables.

Figure 2-68: DMS/DERM Network Model Migration Process



This process is performed whenever a new data model is taken from the GIS or refined in upstream processes. Due to network connectivity nuances evolving in upstream systems to achieve DMS stability, numerous data migrations were required to maintain synchronization with the upstream systems.

Additionally the CIM 61968-Get(Reply)DiscreteMeasurements and ChangedDiscreteMeasurements messages were implemented between the DERM and DMS to maintain synchronization of the DMS and DERM network models as switch status changes are recorded by D-SCADA.

2.2.5.1.1.2 DERM Base Functionality FAT

KCP&L and OATI conducted a Factory Acceptance Test covering the base functionality of the DERM from May 22, 2012 through May 25, 2012. Two KCP&L engineers traveled to Minnesota for this testing, and they also received training on the base system functionality at this time. Throughout the testing, variances were logged and prioritized. The major variances discovered during the FAT were all resolved the month following the testing.

2.2.5.1.1.3 DMS Interface Design

In parallel with standing up the DERM base functionality, KCP&L also went to work designing the interface between the DMS and the DERM. These two systems are tightly coupled, and they require real time synchronizations in order for the DERM to function properly. Since this was a completely new, custom interface, it required lots of face-to-face time between Siemens, OATI, and KCP&L. In order to design the message exchanges for this interface, KCP&L, Siemens, and OATI met for several days to create use cases for the possible scenarios. The main scenarios that were detailed included:

- Initialization scenario between DMS and DERM – used the first time a new database is applied or after one of the systems has been restarted
- Feeder load management scenario –this is an exchange between the DMS and the DERM done in a planning mode and executed from a DMS “study case”
- Feeder load shed or “emergency” scenario–this is an exchange between the DMS and the DERM done in real time when an overload has occurred.

Upon completion of the DMS/DERM use cases, all parties worked on technical specifications for these interfaces to develop the standards-based messages that would be used to exchange the agreed upon information.

OATI and Siemens went through several phases of interface testing, lasting through the first half of 2013. They started by doing simple message exchange testing – sending content to each other via email and manually loading it into their respective systems. Once the vendors agreed on message content, they began sending their messages through the KCP&L Enterprise Service Bus, which had been designed to translate and route the messages appropriately. The OATI system sent and received Web Services messages, and the Siemens system utilized JMS messages. After testing through the ESB, they conducted automated testing, where the message exchanges were triggered from various system events. Finally, Siemens and OATI were able to run through entire use case scenarios and test out the sequence of message flows with internal DMS or DERM applications being triggered as designed.

2.2.5.1.1.4 OpenADR Development

The next major work effort for the DERM component of the project was the DERM/HEMP interface design. KCP&L directed OATI and Tendril (the HEMP vendor) to utilize OpenADR 2.0, profile A, for this interface. KCP&L, OATI, and Tendril all became members of the OpenADR Alliance and became engaged in the OpenADR 2.0 development process. Since the A profile was still under development when the design of the interface was underway, KCP&L agreed to have OATI and Tendril design around a particular working draft. Additionally, KCP&L allowed several modifications to the A profile implementation to facilitate the opt-out functionality that was desired for the project.

OATI and Tendril utilized the following OpenADR messages for the DERM/HEMP interface:

- oadrDistributeEvent to schedule events from the DERM to the HEMP
- oadrCreatedEvent message to confirm events from the HEMP to the DERM

Upon completion of the interface, OATI and Tendril conducted point to point testing of the DR messages. After that, they conducted testing via the KCP&L ESB. Finally, they tested out the end-to-end DR scenarios between the DERM and the HAN devices. The details of the demand response events between the DERM and the HEMP are outlined in Section 2.2.5.2 DR Load Curtailment.

2.2.5.1.1.5 Additional Environment

The DERM differs from most of the other systems deployed in the SGDP, as it is hosted by the vendor instead of managed and maintained by KCP&L. Originally, KCP&L planned to utilize a single instance of the DERM, hosted by OATI in Minnesota. In January 2013, however, as the DMS implementation progressed, the team started to consider the benefits of an additional DERM environment. Since most of the other systems would have two instances, trying to utilize a single DERM for development and production purposes would be complicated. As a result, KCP&L decided to move forward with the configuration and implementation of a second instance of OATI's webDistribute. Upon completion of this system setup, KCP&L connected the development DERM to KCP&L development servers and the development ESB, and they connected the demonstration DERM to its respective demonstration servers and ESB. This was incredibly beneficial to test out various interfaces and environments since so much of the project was divided into various phases.

2.2.5.1.1.6 Battery Interface Development

Early on in the project, KCP&L came up with the concept of "control authorities." The DERM would schedule demand response events, but the control authorities were the systems that actually send the control messages to the end devices that would be utilized for responding to demand response events. KCP&L chose to use the DMS as the control authority for grid-connected resources, such as the battery.

After KCP&L made this decision, Siemens and OATI went to work to design the interface between the DERM and the DMS. OpenADR 2.0 messages were used, and the vendors designed and tested this interface in a similar manner to the major DERM/DMS described above.

2.2.5.1.1.7 ChargePoint Interface Development

The last interface developed from the DERM to a control authority was to the Electric Vehicle Charge System. The ChargePoint system was used as the control system for the ten charging stations deployed in the smart grid project. KCP&L considered using OpenADR 2.0 messages for this interface, but instead they chose to use the existing ChargePoint API. KCP&L also allowed the communications between these systems to be point-to-point rather than traveling through KCP&L's ESB.

2.2.5.1.1.8 Customer Enrollment and Program Creation

While KCP&L and OATI were working on the interfaces to the various control authorities, they also began the process of loading the customer enrollment information into the system and creating the various demand response programs in the DERM. The customer enrollment information links service point identification (SPID) to any residential HAN devices, such as programmable communicating thermostats or load control switches. This information is important so that the DERM knows which assets can be called on for a particular portion of the network. For example, if the DERM received word from the DMS that there was an overload on feeder 7551, then the DERM would be able to dispatch DR to all the devices on that particular feeder.

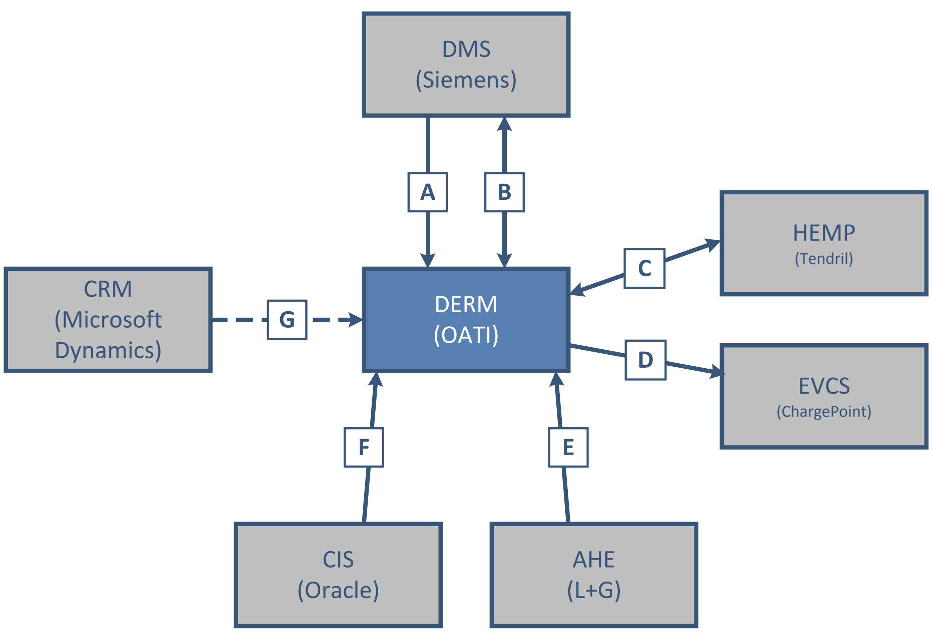
In addition to the enrollment information, KCP&L also worked with OATI to begin creating the DR programs in the DERM. A single device can be enrolled in multiple programs, so for example the smart grid thermostats could be enrolled in both the SG Thermostats program as well as the SG HAN program. Here are the programs that have currently been created in the DERM:

- Test thermostats (only has a few test thermostats enrolled – this was used for testing out DR events in the production environment in a very controlled manner)
- Test load control switches (only has a few test load control switches enrolled – this was used for testing out DR events in the production environment in a very controlled manner)
- SG Thermostats (includes all of the thermostats that were added as part of the SGDP)
- SG Load Control Switches (includes all of the load control switches that were added as part of the SGDP)
- SG HAN (includes all devices that were deployed as part of a smart grid HAN)
- Battery (only has a single asset – the 1MW-Hr battery located outside Midtown Substation)
- ChargePoint (includes the ten electric vehicle charging stations that are part of the ChargePoint interface)
- MPOWER (an existing program for commercial and industrial customers – not part of the smart grid project tariffs, but can be used by the DERM at a later date if desired)
- Optimizer (an existing thermostat program for residential customers – not part of the smart grid project tariffs, but can be used by the DERM at a later date if desired)

2.2.5.1.2 Integration

An overview of DERM system-to-system interfaces and applicable messages is illustrated in Figure 2-69.

Figure 2-69: KCP&L SmartGrid Demonstration Project DERM Integration



The DERM system interfaces with many other KCP&L systems, both for synchronized network models and customer/program enrollment, and for dispatching DR events to various control authorities. The integration touch points for the DERM are as follows:

A. DMS/DERM Data Model Propagation: The DERM system must synchronize its data model with the D-SCADA to make accurate calculations of its own. The network connectivity model and associated loads are transferred from the DMS to the DERM using a manual CIM RDF export. Generation of the CIM RDF file is done in the IMM and then exported via file transfer to OATI. This process is performed whenever a new data model is taken from the GIS, and it requires massaging from OATI to ensure that it's properly digested by the DERM.
B. DMS/DERM Dynamic Data Exchange: In addition to the static model data that's exchanged between the DMS and the DERM, the two systems also exchange a number of dynamic messages on an as-needed basis. The DERM sends and receives Web services messages, whereas the DMS sends and receives JMS (Java Messaging Service) messages, so adapters within KCP&L's ESB serve as translators between the two systems. The dynamic data exchanged between the DMS and the DERM can be categorized by the following interfaces:
    - Network Topology Interface – Upon initial synchronization of the two databases, the DERM is notified about each switch state change.
    - Distribution Power Flow (DPF) Interface – The DPF interface allows the DERM to query DPF results from the DMS. For scheduled DERM events, the DERM needs calculated overloads on an hourly basis. The DPF interface generates the data and makes it available to DERM. Additionally, violations are published to the DERM in real time.
    - Study Case Interface – When study cases are created in the DMS, a study case needs to be created in the DERM, as well. This interface provides the messages to do so.
    - Demand Response Event Interface – DR events affect power flow results, so DERM needs an interface for publishing DR events to the DMS.
    - Battery Interface – The DMS is used as the control authority for the battery, so this interface is used to dispatch DR events for this purpose.
C. DERM/HEMP DR Messaging: This interface includes both the Demand Response Event request initiated from DERM to HEMP, and Event Opt-Out/Opt-In reply initiated from HEMP (for both HANs and Stand-alone PCTs) to DERM. These are OpenADR-formatted request-reply messages used to notify HEMP of creation, modification, or cancellation of impending DR events and to notify DERM of DR assets' event participation status.
D. DERM/EVCS DR Propagation: A uni-directional interface used to dispatch DR events from the DERM to the ChargePoint EVCS system. All data exchanges in this interface are transmitted via Web Services using ChargePoint's existing API.
E. AHE/DERM Metering Data: A uni-directional interface from the AHE to the DERM on a daily basis with the previous day's metering interval data. The DERM needs this information to create and update customer baselines. These daily batch files are transferred from the AHE to the DERM via an SFTP server.
F. CIS/DERM Service Point Data: A uni-directional interface from the CIS Server to the DERM on a weekly basis. This transfer is used to link SPID to any residential HAN devices, such as PCTs or LCSs. This information is important so that the DERM knows which assets can be called on for a particular portion of the network. These weekly files are transferred from KCP&L's CIS Server to the DERM via an SFTP server.

G. Customer Enrollment Data: A uni-directional interface from a combination of data from the CRM, HEMP, and AHE. This file needs significant manual work currently, but the long-term goal is for this process to be automated and sent on a weekly basis. This transfer is used to inform the DERM of DR program enrollment information so that the DERM can link HAN devices with the programs that they're associated with, and to map DR capabilities with distribution transformers. These Excel files are currently transferred via email from KCP&L to OATI for manual loading into the DERM.

2.2.5.1.3 Post-Implementation Operational Issues

Following the stand-up and preliminary testing of the DERM, several post-implementation operational issues needed to be mitigated and considered. These issues were as follows:

- Heartbeat Message - The first post-operational issue with the DERM was the addition of a "heartbeat" message between the DERM and the DMS. This additional message was designed to give KCP&L system operators an alarm on the DMS system summary if the communications path between the two systems was severed for any reason.
- Test Data – Another post-operational issue had to do with the test data that was created during the DERM system build and test phases. During the years leading up to the actual operational use of the system, KCP&L entered an abundance of fictitious asset, program, resource, and customer data to test out the system functionality. When it came time to actually use the system for production demand response events during the summer of 2014, a serious data cleansing was necessary to carefully rid the system of all the data that had been created for testing purposes.
- Log Storage Duration – The OATI inbound and outbound logs were very helpful when developing and testing the interfaces with the other back office systems. They were also beneficial for maintaining the historical DR events that were dispatched during the summer of 2014. However, part way into the production DR season, KCP&L realized that the logs are only stored for two weeks. As a result, KCP&L had to maintain the dispatched DR messages elsewhere.
- Development and Production Environment Discrepancies – Since KCP&L used two instances of the DERM throughout the project, there were several issues where the development environment didn't match the production environment. Sometimes this was just a minor concern – for example, when the KCP&L users had only created a particular DR program in the test system. For these instances, KCP&L just had to duplicate efforts in order to keep both systems in synch. Other times, however, the discrepancies were much more problematic. When KCP&L was preparing to trigger a DR event from a DMS overload, issues arose in the production environment. KCP&L went back and tested the same scenario on the development environment and everything worked properly. Upon further investigation, KCP&L and OATI realized that the data model on the production environment didn't match the one on the development environment. This issue required significant time and resources to resolve.

2.2.5.1.4 Lessons Learned

Throughout the build of DERM, numerous considerations were realized and should be noted for future deployments of this sort. These Lessons Learned are as follows:

- Model Propagations are Complex - One of the lessons learned with the DERM/DMS integration was that the model propagation between systems is not a trivial feat. Even though the two vendors agreed upon a common version of the CIM data model, there were still issues and tweaks with each model propagation. If models were updated on a more regular basis in the future, the process would need to be refined so that it wouldn't take such a significant effort.

- Standards Not Sufficient for DMS/DERM Interactions – For the SGDP, Siemens and OATI created a custom DMS/DERM interface. They utilized IEC 61968 for dynamic message exchanges, but they had to create numerous extensions to the standard in order to pass the necessary information between systems. A significant amount of industry work needs to happen in this standard in order for it to be sufficient for the exchange of power flow and state estimation messages.
- Interface Logs Critical for Interface Development - The last lesson learned from the DERM implementation was that having access to system logs can be extremely helpful during development and integration of a new system. The webDistribute logs are available to the DERM user, and they were very beneficial while testing out the interfaces to all of the control authorities.

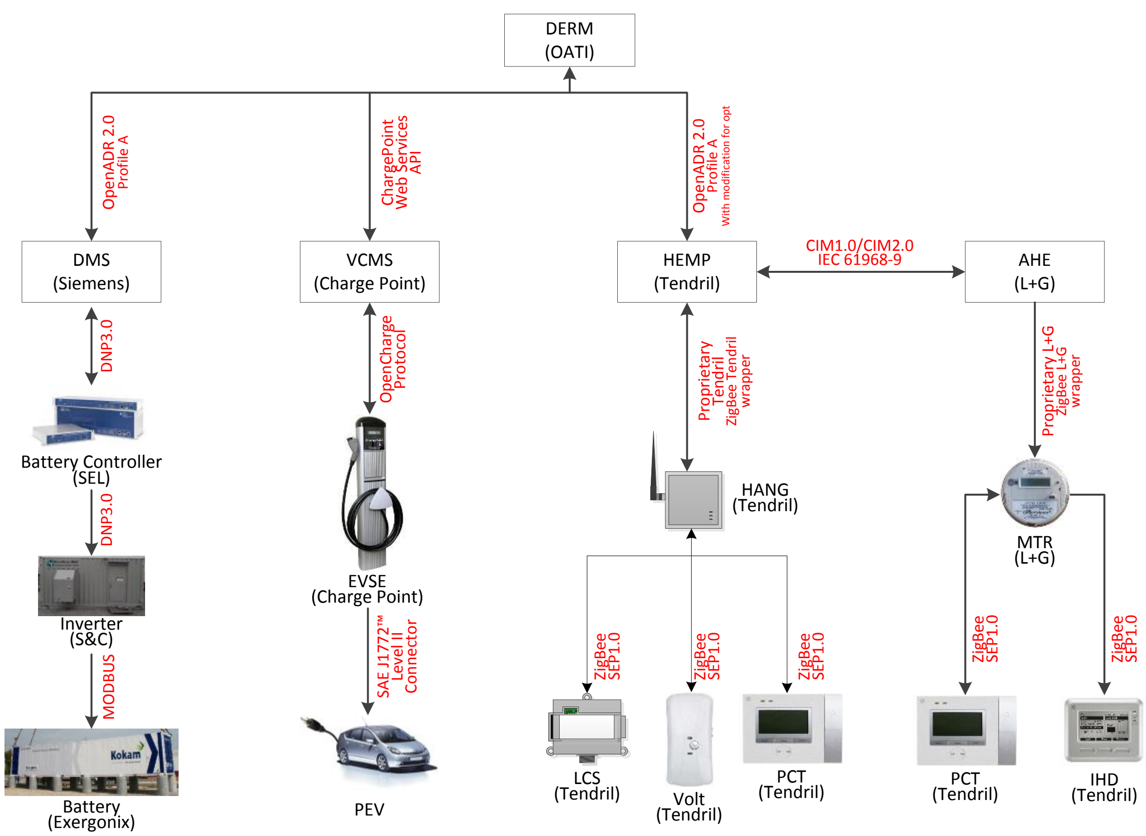
2.2.5.2 DR Load Curtailment

The following sections provide a summary of the development and configurations that were required to implement and deploy the SmartGeneration DR Load Curtailment functionality.

2.2.5.2.1 Build

The DR load curtailment programs developed for the SGDP all required deployment and configuration of DR resources and messaging infrastructure. The development and testing for each program varied depending on the environments available and the messaging standards used. The DR load curtailment integration architecture implemented is illustrated in Figure 2-70.

Figure 2-70: Demand Response Load Curtailment Architecture



2.2.5.2.1.1 Residential Stand-alone Programmable Communicating Thermostat

The Stand-alone PCT is described in detail in Section 2.2.2.3. Through integration between the DERM, HEMP, and AHE, the Stand-alone PCTs can receive demand response events to help reduce, level, or shift load during peak demand periods. The DERM can forecast demand on the distribution grid and call on the Stand-alone PCTs for load reduction, if necessary. A message is sent from the DERM to the HEMP to identify the Stand-alone PCT customers needed to meet the load reduction requirements. The HEMP then routes the demand response messages to the AHE. The AHE passes the demand response events to the Stand-alone PCTs via the SmartMeters prior to or at the start time of the event, depending on the event parameters. Once received at the Stand-alone PCT, the customer is automatically opted into event participation with the option to opt out of the event at any time prior to the end of the event. This opt-out/in decision can be made directly at the device. Customer event participation information is then passed to the DERM via the AHE and HEMP to be used for post-event analysis and future demand response forecasting.

In order to test the DR events to the stand-alone PCTs, KCP&L utilized the development DERM, HEMP, and AHE systems. Messages were triggered manually in the DERM and propagated from system to system, through the development ESB, to the PCTs in the lab environment. Testing in this environment allowed KCP&L to work out issues with firmware versions, messaging structure, and ESB routing, which ensured that no customers would be impacted throughout the intense testing period.

Once KCP&L was comfortable with the testing results in the development environment, they began testing in the demonstration environment prior to the summer 2014 demand response season. In order to do this without impacting customers, test events were sent to PCTs tied to the demo house and the Midtown substation battery control enclosure. This allowed the team to verify the DR messaging infrastructure in the demonstration environment, but it didn't impact any customers.

In preparation for the summer 2014 demand response season, KCP&L cleared out and updated the customer, asset, program, and resource information associated with the stand-alone PCT program. The stand-alone PCTs were used for two types of demand response events during the summer of 2014 – events triggered by the DERM and events triggered by an overload in the DMS. Refer to Section 3.4.6.4 for details and results of the demand response test events.

2.2.5.2.1.2 Residential Home Area Network

The Home Area Network is described in detail in Section 2.2.2.4. Through integration between the DERM and the HEMP, the HAN can receive demand response events to help reduce, level, or shift load during peak demand periods. The DERM can forecast demand on the distribution grid and call on the HANs for load reduction, if necessary. A message is sent from the DERM to the HEMP to identify the HAN customers needed to meet the load reduction requirements. The HEMP then routes the demand response messages to the HAN gateways via the broadband connection. The HAN gateway passes the demand response events to the PCTs and LCSs prior to or at the start time of the event, depending on the event parameters. Once received at the PCTs and LCSs, the customer is automatically opted into event participation with the option to opt out of the event at any time prior to the end of the event. This opt-out/in decision can be made directly at the PCTs and LCSs or via the Customer Web Portal. Customer event participation information is then passed to the DERM via the HEMP to be used for post-event analysis and future demand response forecasting.

In order to test the DR events to the HANs, KCP&L utilized the development DERM and HEMP systems. Messages were triggered manually in the DERM and propagated from system to system, through the development ESB, to the HANs, PCTs, and LCSs in the lab environment. Testing in this environment allowed KCP&L to work out issues with firmware versions, messaging structure, and ESB routing, which ensured that no customers would be impacted throughout the intense testing period.

Once KCP&L was comfortable with the testing results in the development environment, they began testing in the demonstration environment prior to the summer 2014 demand response season. In order to do this without impacting customers, test events were sent to HAN devices tied to the demo house and the Midtown substation battery control enclosure. This allowed the team to verify the DR messaging infrastructure in the demonstration environment, but it didn't impact any customers.

In preparation for the summer 2014 demand response season, KCP&L cleared out and updated the customer, asset, program, and resource information associated with the HAN program. The PCTs and LCSs under the HANs were used for two types of demand response events during the summer of 2014 – events triggered by the DERM and events triggered by an overload in the DMS. Refer to Section 3.4.6.4 for details and results of the demand response test events.

2.2.5.2.1.3 Battery Energy Storage System

The BESS is described in detail in Section **Error! Reference source not found.**. Through integration etween the DERM and the DMS, the BESS can receive demand response events to help reduce, level, or shift load during peak demand periods. The DERM can forecast demand on the distribution grid and call on the battery to discharge, if necessary. One of the underlying assumptions with this interface is that anytime the battery is placed in DERM mode, the battery is fully charged. This way, the DERM has the potential to discharge the entire battery. Additionally, when the battery is in DERM mode, it cannot be used for other schemes. To utilize the battery for DR, a message is sent from the DERM to the DMS to identify the amount of battery discharge needed to meet the load reduction requirements. The DMS then routes the shed load message to the SICAM, which passes the setpoints on to the Real Time Automation Controller (RTAC). The RTAC then sends the DR battery shed load message on to the inverter, which finally sends the event instructions to the battery itself. The battery will begin to discharge at the rate specified at the designated start time, for the specified duration.

In order to test the DR events to the battery, KCP&L utilized the development DERM and DMS systems. This testing occurred in December 2013. Messages were triggered manually in the DERM and propagated through the ESB to the DMS in the development environment. From the DMS, the setpoints were routed to the SICAM, and then on to the RTAC. In the development environment, KCP&L had no way to verify the last stages of the message propagation; rather, they had to assume that the RTAC logic would properly discharge the battery.

In February 2014, KCP&L began testing in the demonstration environment. First, the team conducted interface tests from the RTAC to the inverter to the battery. Once the issues with those interfaces were resolved, then they tested from the DERM. Refer to Appendix K.4 for details of the battery DR end-to-end flow.

2.2.5.2.1.4 Vehicle Charge Management System

The VCMS is described in detail in Section **Error! Reference source not found.**. Through integration etween the DERM and the ChargePoint system, charging stations can receive demand response events to help reduce, level, or shift load during peak demand periods. Although KCP&L knew that the DR events to the charging stations wouldn't likely result in much load reduction, they wanted to develop and test out this interface to demonstrate the possibilities for a larger, enterprisewide VCMS implementation. To utilize the charging stations for DR, a message is sent from the DERM to the ChargePoint system to indicate which charge stations should be turned off at a particular time. The DERM could forecast demand on the distribution grid and call on specific charging stations at particular network locations to stop charging vehicles, if necessary. For the SGDP, KCP&L didn't test out geographically targeted DR events to the charging stations, but this would be feasible by loading a few additional charge station characteristics into the DERM.

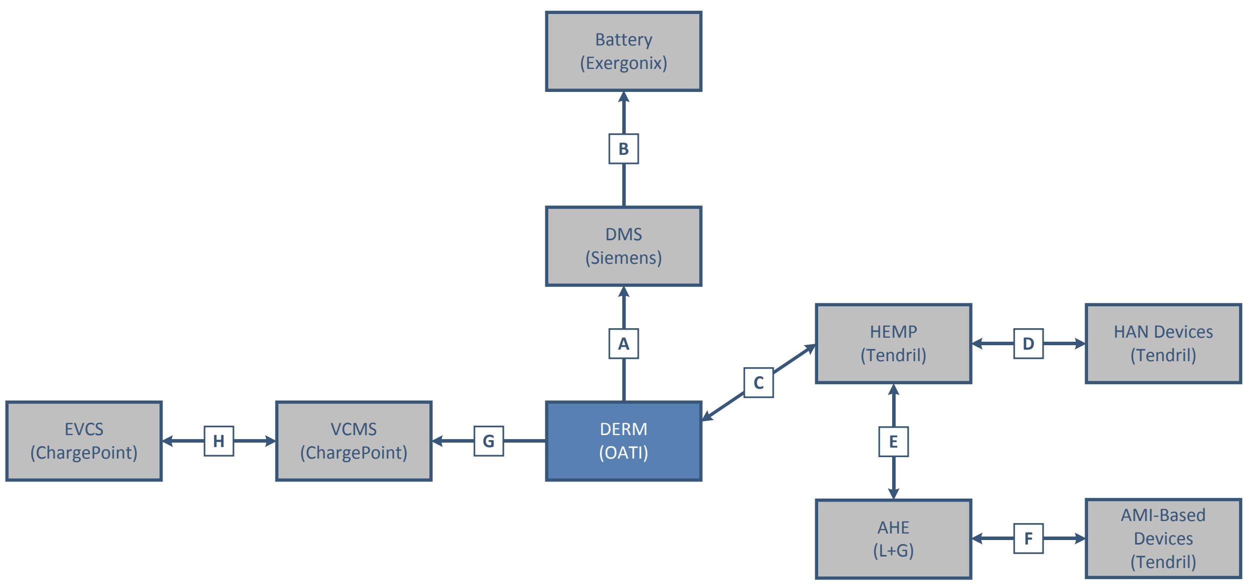
Unlike the other control authorities, the interface from the DERM to the VCMS is a point-to-point interface. This made testing a lot less complicated, as the traffic didn't need to be routed through the KCP&L ESB. OATI and ChargePoint developed a point-to-point interface via the Internet utilizing ChargePoint's existing API function calls. In order to test DR events to the charging stations, KCP&L simply added the charging stations to the DERM and triggered events to specific stations. Since there wasn't a development VCMS, the testing was done to an actual production charge station. KCP&L was able to ensure that no vehicles were plugged into specific charging stations during this preliminary testing by using the ChargePoint web UI. They were able to verify message propagation from the DERM to the VCMS via the ChargePoint web UI. Tests were also verified by looking at the screen located at the charging station to see how the text changed during DR events.

Production testing with an actual electric vehicle plugged into the station occurred in August 2014. Refer to Section 3.4.6.4 for details and results of this VCMS demand response testing.

2.2.5.2.2 Integration

An overview of system-to-system interfaces relevant to DR Load Curtailment and applicable messages is illustrated in Figure 2-71.

Figure 2-71: KCP&L SmartGrid Demonstration Project DR Load Curtailment Integration



The Demand Response Load Curtailment programs require many system-to-system and system-to-device interfaces. These integration touch points are as follows:

A. Demand Response Event request initiated from DERM to DMS. These are OpenADR-formatted request messages sent via the KCP&L ESB and used to notify the DMS of creation, modification, or cancellation of impending DR events to the battery.

B. Demand Response Event requests initiated from DMS to the battery via the Real Time Automation Controller (RTAC) and the Inverter. These events are DNP3.0 between the DMS to the RTAC and down to the Inverter, and they are Modbus from the inverter to the battery itself. They consist of three set points: kW discharge rate, start time, and duration.

C. Demand Response Event request initiated from DERM to HEMP, and Event Opt-Out/Opt-In reply initiated from HEMP (for both HANs and Stand-alone PCTs) to DERM. These are OpenADR-formatted request-reply messages used to notify HEMP of creation, modification, or cancellation of impending DR events and to notify DERM of DR assets' event participation status.

D. Demand Response Event requests initiated from HEMP to HAN DR assets via the Internet, and Event Opt-Out/Opt-In replies initiated from HAN DR assets to HEMP via the Internet. These are ZigBee SEP 1.0-formatted request-reply messages used to notify HAN DR assets of creation, modification, or cancellation of impending DR events and to notify HEMP of HAN DR asset event participation status.

E. Demand Response Event request initiated from HEMP to AHE, and Event Opt-Out/Opt-In reply initiated from AMI-based DR assets (Stand-alone PCTs for this project) to HEMP. These are IEC 61968 CIM-formatted request-reply messages used to notify AMI-based DR assets of creation, modification, or cancellation of impending DR events and to notify HEMP of AMI-based DR assets' event participation status.

F. Demand Response Event requests initiated from AHE to AMI-based DR assets (Stand-alone PCTs for this project) via SmartMeters, and Event Opt-Out/Opt-In replies initiated from AMI-based DR assets to AHE via SmartMeters. These are ZigBee SEP 1.0-formatted request-reply messages used to notify AMI-based DR assets of creation, modification, or cancellation of impending DR events and to notify AHE of AMI-based DR asset event participation status.

G. Demand Response Event request initiated from DERM to VCMS. These messages are sent via the Internet (not through KCP&L's ESB), and they utilize ChargePoint's existing API. They are used to notify the VCMS of creation, modification, or cancellation of impending DR events to the charge station infrastructure.

H. Demand Response Event requests initiated from VCMS to the EVCS, and Charge Station Status messages about the real time status of charging stations sent from the EVCS to the VCMS for display on the ChargePoint GUI. Messages in this interface are passed via the Internet using the OpenCharge Protocol.

2.2.5.2.3 Post-Implementation Operational Issues

Following the stand-up and preliminary testing of the demand response functionality, several post-implementation operational issues needed to be mitigated and considered. These issues were as follows:

- Infrastructure Re-testing - Because demand response is used seasonally, the associated interfaces can be unused for months at a time. As a result, KCP&L found that the DR infrastructure needs to be retested/revalidated periodically, at the beginning of each DR season.
- Meter Swap Outs and Customer Turnover – Each time a meter is replaced or a customer moves in/out, the meterID and SPID linkages need to be updated throughout the relevant back office systems. Additionally, the HAN devices associated with one customer account aren't transferred to the next account when a new person moves in. As a result, assets are left stranded – they aren't moved to the new residence, but they aren't usable by the new resident at the original premises without significant manual intervention. If deployed on an enterprisewide scale, careful thought would need to be given as to how to efficiently transition assets with move ins/outs. Strategies might differ between houses and apartments.
- Event Message Validation Rules – When KCP&L initiated the first production DR event, the entire event failed due to validation rules in Tendril's OpenADR Appliance. Upon investigation, KCP&L discovered that the Tendril Appliance failed the inbound DR message if *any* of the target accounts no longer existed. So if any move ins/outs had occurred since the last synch between the DERM, HEMP, and CIS, then the production event wouldn't

succeed and *none* of the thermostats would receive the event. In order to resolve this issue, KCP&L initiated DR events well in advance of the event start time – that way, they were able to modify participants in the DERM and reschedule the event after eliminating the problematic devices. For enterprisewide deployment, a more automated process would be necessary.

2.2.5.2.4 Lessons Learned

Throughout the build, implementation, and daily operation of the DR Load Curtailment programs, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- Multiple Environments - Testing demand response flows in multiple environments was challenging. Originally, KCP&L only utilized a single instance of the DERM, but this led to issues when testing out various flows, as the DERM could only dispatch DR messages to a single instance of the ESB, either development or production. With a single instance of the DERM, KCP&L had to orchestrate consistent phasing between development and demonstration environments in the DERM, DMS, HEMP, AHE, and ESB. Configuring an additional DERM made it feasible to test residential flows in the demonstration environment while testing battery flows in the development environment, for example.
- Transitioning Devices - Due to customer turnover, residential DR assets can get "lost." The industry needs to come up with processes for transitioning these devices to their new customer, or to at least make the provisioning process more automated if the devices are to move with the owner to a new place of residence.
- Customer Broadband Active Monitoring – For KCP&L's project, the HAN implementations relied upon the customer's broadband internet connection to communicate between the HAN Gateway and the HAN devices. Unfortunately, this meant that anytime the internet connection was down, that customer's DR assets could not be utilized for DR events. As a result, KCP&L didn't expect any reduction from HAN implementations; rather, any reduction from these customers was icing on the cake. In the future, active monitoring would allow the DERM to accurately forecast whether DR devices within a HAN could be counted on to participate.
- OpenADR 2.0 Development - Another lesson learned (in multiple implementations on the SGDP) was that the standards creation process can be slow and tedious. In order to utilize OpenADR 2.0, KCP&L had to pick a working draft version of the profile and implement to that version. Waiting for the "completed" profile would have been detrimental to the project schedule, so this wasn't an option. Once the OpenADR 2.0 profiles are fully vetted and a vendor certification process is in order, it will be a lot easier and faster for companies to develop their products to the new standard.
- Standards Testing Agency – In addition to a standard profile, there is a clear need for testing agencies to certify deployments of a particular standard. Even with profiles, there is room for interpretation, so testing bodies will help to ensure consistency in the certification process across vendors.
- Control Authority Logic – For KCP&L's implementation, the DERM sent the HEMP a list of assets for participation as opposed to group name. The grouping logic was done at the DERM level, but for an enterprisewide deployment, it makes more sense for this logic to occur in the respective control authority. For example, the DERM would send a DR event to the HEMP, addressed to a particular section of the network. The HEMP would translate this network segment into a DR event dispatched to a list of devices in that segment. This type of design would also position the DERM to interface with external aggregators.

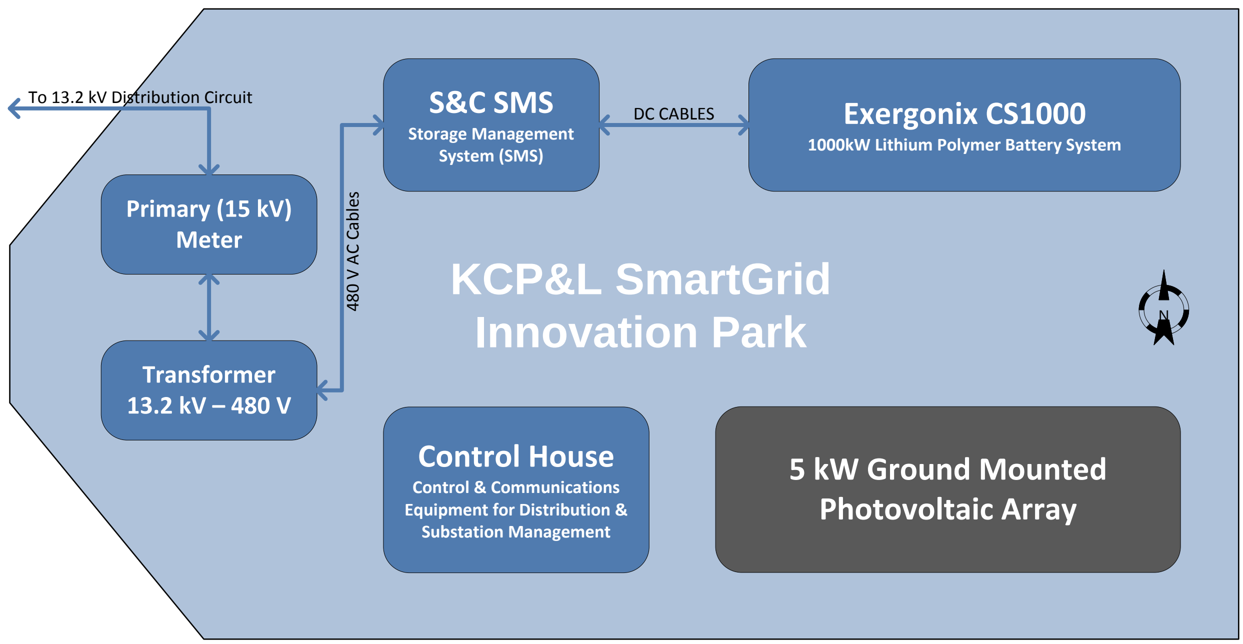
2.2.5.3 Battery Energy Storage System

As part of the KCP&L SGDP, a 1.0 MW, 1.0 MWh lithium-polymer grid-connected BESS manufactured by Exergonix was installed adjacent to the Midtown Substation. This system includes a 1.25 MVA Storage Management System (SMS), power converter, manufactured by S&C Electric. The following sections provide a summary of the development and configurations that were required to implement and deploy the SmartGeneration DR Load Curtailment functionality.

2.2.5.3.1 Build

Figure 2-72 provides a schematic of the energy storage project's layout at KCP&L's SmartGrid Innovation Park. The site includes the BESS, SMS, SGDP pilot control house equipment, step-up transformer (13.2kV-480V), and associated metering and monitoring equipment. It also includes a 5.0 kW ground-mounted PV array that is grid-connected to the same circuit as the battery through the control house transformer (13.2kV-110V).

Figure 2-72: Innovation Park and BESS Site Overview



2.2.5.3.1.1 Battery Testing and Installation

The BESS was unit tested by Exergonix at the factory in Korea and the SMS was unit tested with a scaled-down version of the BESS at an S&C facility in Wisconsin. As a part of the installation process, MRI Global performed site acceptance testing of the BESS to verify the battery met the specified round-trip efficiency of 90%. MRI Global conducted tests and calculated the round trip efficiency of BESS to be 92%. Appendix G contains the complete MRI BESS Acceptance Testing Report.

KCP&L broke ground on the grid connected Battery site in early February 2012 and the BESS arrived in March 2012 after successful completion of factory testing. Interconnection of the SMS and the BESS occurred in May 2012 and site acceptance testing was performed by MRI in May and June 2012. The site was completed and unveiled at the opening of the SmartGrid Innovation Park in October 2012. The completed battery system installation is shown in Figure 2-73. The battery enclosure is wrapped in educational content to facilitate community awareness and engagement.

Figure 2-73: BESS Installation

2.2.5.3.1.2 Battery Automation Controller

Remote and advanced operation of the BESS through SCADA integration with the DMS is accomplished through the utilization of a custom programmed SCADA controller, the Battery Automation Controller (BAC). The BAC receives control settings from distribution operators or from the DERM via the DMS/DDC. In addition, real-time load data from relays within the substation are provided to the BAC from the DMS/DDC to enable load following storage operations.

2.2.5.3.1.3 Distribution Operation

The battery can be controlled via three means – the distribution operators, the DERM, and locally. Distribution operators may initiate charge/discharge/reactive events within the BESS through the DMS interface. The operator can set various system-level settings through binary and analog points as well as define events through additional analog points. The BAC receives these binary and analog points, processes them, and sends the corresponding SCADA commands to the SMS as required in order to execute the programmed event.

The BAC enables three charge modes, five discharge modes, and four reactive modes:

- Charge Modes:
  - Fixed Charge – specified kW and duration
  - Load Following Charge Feeder – calculated kW based on current feeder load to maintain specified net feeder load
  - DERM Fixed Charge – specified kW and duration
- Discharge Modes:
  - Fixed Discharge – specified kW and duration
  - Load Following Discharge Feeder – calculated kW based on current feeder load to maintain specified net feeder load
  - Load Following Discharge Buss – calculated kW based on current bus load to maintain specified net bus load
  - Load Following Discharge Transformer – calculated kW based on current transformer load to maintain specified net transformer load
  - DERM Fixed Discharge – specified kW and duration

- Reactive Modes:
  - Fixed VAR – specified kVAR and duration
  - Load Following VAR Feeder – calculated kVAR based on current feeder power factor to maintain specified net feeder power factor
  - Load Following VAR Bus – calculated kVAR based on current bus power factor to maintain specified net bus power factor
  - Load Following VAR Transformer – calculated kVAR based on current transformer power factor to maintain specified net transformer power factor

2.2.5.3.1.4 DERM Operation

The BESS is also a controllable Distributed Energy Resource that the DERM may define and engage in a DR event. The DERM sends event information to the DMS via an OpenADR message. The DMS then checks to ensure the BAC is in DERM mode and then automatically sets the corresponding analog points in the BAC which then sends corresponding SCADA commands to the SMS. The DERM only engages the BESS in Fixed Discharge mode as executed by the BAC.

2.2.5.3.1.5 Local Operation

The BESS may also be programmed to charge/discharge on a daily schedule via the local HMI interface in the SMS. One charge event and up to two discharge events may be programmed to occur each day. Each event is based on twenty custom programmable profiles. Each profile is defined by four time/amplitude points (trapezoidal).

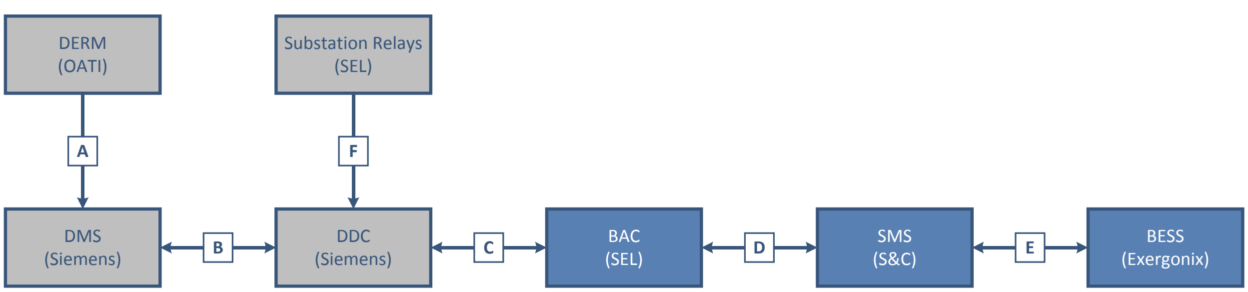
2.2.5.3.1.6 Remote Access

In addition to the three primary operations, KCP&L also enabled remote access to the HMIs of both the SMS and the BESS through secure corporate network connection on direct fiber. This remote access facilitates health monitoring, troubleshooting and emergency control.

2.2.5.3.2 Integration

An overview of system-to-system interfaces relevant to the BESS and applicable messages is illustrated in Figure 2-74.

Figure 2-74: KCP&L SmartGrid Demonstration Project BESS Integration



The BESS control functions require many system-to-system and system-to-device interfaces. These integration touch points are as follows:

A. Demand Response Event request initiated from DERM to DMS. These are OpenADR-formatted request messages sent via the KCP&L ESB and used to notify the DMS of creation, modification, or cancellation of impending DR events to the battery. Upon receipt of the DR event messages at the DMS, the messages are converted to control signals.

B. Battery Control Signals sent from the DMS to the DDC and Battery Status Updates sent from the DDC to the DMS for display on the GUI. These messages are IEC61850 messages, and they consist of various setpoints, controls, indicators, and analogs.
C. Battery Control Signals sent from the DDC to the BAC and Battery Status Updates sent from the BAC to the DDC for upstream propagation back to the DMS. These messages are DNP3.0 messages transmitted via the Tropos wireless mesh network, and they consist of various setpoints, controls, indicators, and analogs.
D. Battery Control Signals sent from the BAC to the SMS and Battery Status Updates sent from the SMS to the BAC for upstream propagation back to the DMS. These messages are DNP3.0 messages, and they consist of various setpoints, controls, indicators, and analogs.
E. Battery Control Signals sent from the SMS to the BESS and Battery Status Updates sent from the BESS to the SMS for upstream propagation back to the DMS. These messages are Modbus messages, and they consist of various setpoints, controls, indicators, and analogs.
F. Real Time Load Data sent from substation relays to the DDC and on to the BAC. This data consists of IEC61850 MMS messages, and it enables load following storage operations.

2.2.5.3.3 Post-Implementation Operational Issues

Energy storage represents a new technology for KCP&L grid operations. Following the installation, integration, and site acceptance testing of the BESS, numerous post-implementation operational issues were encountered that needed to be mitigated and considered. These issues are as follows:

- Post-Deployment Training – The BESS is a high voltage source that lacks visible or audible warning conditions typically present at traditional generators such as a combustion engine running. As a result, KCP&L Field crews have undergone extensive training to address BESS system awareness and on-site safety during maintenance and emergency response activities.
- Alarming – The BESS is an extremely complex system with numerous alarms and component failure conditions. While the SMS and BESS control systems are capable of isolating alarmed components or battery cells, on numerous occasions, various alarms have caused delays in testing or normal charge/discharge operations due to alarm investigation and troubleshooting. Some example alarm or failure conditions that have been encountered include:
  - Voltage imbalance between battery cells. Out of balance cells are automatically omitted from charge/discharge events, reducing the active capacity of the BESS.
  - Environmental control system failure requiring emergency repair. Operations ceased due to cell overheat risk.
- Component Replacement – Various component replacements have been difficult and time consuming to accomplish due to a lack of local vendor support.
- CT/PT Placement for Metering - The CT/PTs used for the SMS PCS HMI was initially connected to the BESS 13.2 kV metering CT/PTs on high side of the distribution transformer to aid in synchronized recovery from “islanding”. This caused SMS to capture the output of battery and inverter along with the power consumed by the auxiliary loads and transformer losses. After the SMS PCS HMI connection was changed to the internal SMS CT/PT on the source side of the PCS, the data recorded by the SMS included the output from battery and inverter only. The output was smoother and excluded the auxiliary loads.

- “Fuller Brush” Effect - The output of PCS and battery was fluctuating during the charging and discharging period. During the charge cycle, the output fluctuated for first few hours and then settled after that, resembling “Fuller Brush”. During the discharge cycle, the output fluctuated the entire discharge period. The vendor fine-tuned and changed the regulator setting for smooth power output.
- “Spikes” – The power output of the PCS and battery combined dropped to zero during charge and discharge period and spiked to 200 kW during the idle period. At a closer look, it was found that these spikes were occurring every two hours and at the same time caused a 6 hour time-shift (5 hour time shift during daylight savings time) in SMS data. It was found that the Real Time Automation Controller (RTAC) was syncing its time with SMS every 2 hours. Since, the SMS was in Universal Time Coordinated (UTC) zone and RTAC in local Central time zone, the RTAC was requesting time sync with SMS and caused a 5/6 hour time shift. The RTAC code was adjusted to set SMS in UTC and logic was changed to stop time syncing every 2 hours.
- High Power Output during idle period – The auxiliary loads such as HVAC, lighting, control systems, etc. is supplied by the grid during the charging and idle period and supplied by the battery during discharging period. After the PCT control CT/PTs were changed to the internal 480 V line, the SMS HMI still showed some abnormal usage during idle times. When the auxiliary load connections were checked, it was found that some were connected between the PCS and PCT control CT/PTs. The auxiliary loads were reconnected to the grid side of the PCS CT/PTs.
- Charge during Discharge cycle – After a thorough review of PCS and battery power output, it was found that at the end of discharge cycle, the battery charged for 10 minutes at 8 kW to 10 kW. The vendor made setting changes in SMS to eliminate this issue.

2.2.5.3.4 Lessons Learned

Throughout the implementation and daily operation of the BESS, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- Since lithium cells require a relatively narrow operating temperature range, the environmental control system is vital to proper operations. It should consist of a hardened design intended to withstand extreme conditions and high reliability. The system should be inspected regularly to ensure proper operation. KCP&L recommends inspection and test of the environmental control and other support systems for the BESS every quarter or prior to each seasonal change.
- In the analysis of round trip efficiency of BESS, it was noticed that the round trip efficiency of BESS was dependent on the daily average temperature. To improve operational performance on any future BESS implementation, specifications should focus on improving the efficiency of auxiliary loads and installing improved insulation and more efficient HVAC units on the SMS and battery enclosures.
- The placement of auxiliary loads relative to the SMS PCS CT/PTs is critical for proper control of battery operation. The auxiliary loads must be connected to the grid side of the SMS PCS CT/PTs so that the SMS is directly monitoring the AC output of the PCS. Proper connection of the auxiliary loads should be verified during site acceptance.
- Site acceptance testing needs to include macro-analysis of charge/discharge cycles to identify any irregularities and fine-tune the settings to get the desired and smooth power output.
- Learned that manufacturer’s recommended that the battery should not be routinely discharged below a 20% charge level to protect the battery and maintain its life. This

limitation must be factored in when sizing the battery storage component for any BESS. Hence, a 1.0 MWh battery is not a 1.0 MWh battery. The 1.0 MWh battery can only deliver a 780 kWh (1,000 x 80% x 97.6% = 780) net impact to the grid.

- Due to the complexity and lack of experience with grid-scale energy storage assets by vendors and within KCP&L, the BESS required a long and tedious operational learning curve. Despite extensive documentation from vendors, numerous conditions and operational applications required consultation and/or direct support from vendors. For example, programming the charge/discharge schedule within the SMS was not documented well enough for KCP&L personnel to execute reliably without intermittent support from vendor representatives. Also, some alarm scenarios arose that weren't well defined in advance or within documentation to facilitate KCP&L direct troubleshooting. KCP&L recommends extensive hands-on training of key personnel in the presence of vendor representatives on all planned operational applications, alarms, and known emergency scenarios. This may represent a significant expense and inconvenience for internal personnel but will result in timely resolution to a majority of anomalous conditions and enable the asset to have greater overall availability.
- Locating this BESS was limited by the KCP&L SGDP geographical footprint and the research goal to demonstrate circuit islanding (needed a circuit with load levels that could be managed by the BESS). As a result, the BESS is interconnected at the head of a short stable urban circuit. This circuit typically exhibits stable primary voltages and power factor thus limiting the operational value and demonstration value of the BESS. Despite these limitations, net impacts of the BESS are clearly observable in operational circuit data. KCP&L recommends narrowing applications for grid-scale energy storage assets to one or two key distribution network trouble areas.
- Lithium polymer battery cell systems are well suited for high frequency and high power applications that require the system to transition from charging to discharging quickly. Target applications might include frequency regulation, renewable integration and ramp-rate management, renewable output smoothing, etc. However, due to a comparatively high cost for energy volume (kWh), this battery technology may not be well suited for energy shifting or peak shaving applications.

2.2.5.4 Solar PV

As part of the SGDP, KCP&L is working to install approximately 180 kW of diverse solar photovoltaic (PV) systems on commercial properties throughout the pilot project area. The PV systems, with the exception of those installed on utility property, were established through a lease agreement in which KCP&L leases rooftop space but owns and maintains the PV system for a multi-year contract period. Each system will be directly grid connected and metered independently for tracking purposes.

2.2.5.4.1 Build

KCP&L completed the installation of nine separate PV systems with a total nameplate capacity of 176.9 kW. Installed systems are summarized in Table 2-13.

Each of the solar PV systems is connected directly to the grid through an AMI meter. The kWh generated and consumed by the system is captured in 15-minute interval data and sent to KCP&L's Data Mining and Analysis Tool. DMAT provides the ability to display and download the data for analysis.

Table 2-13: Smart Grid PV Systems Installed

System Location	Panel Technology	Inverter	Capacity (kW)	In-Service Date
Project Living Proof (Demonstration Home)	Monocrystalline	String	3.15	01/19/2011
Paseo High School Gymnasium Rooftop	Monocrystalline	String	99.18	04/19/2012
Innovation Park (Midtown Substation)	Monocrystalline	String	5.00	10/17/2012
Crosstown Substation	Polycrystalline	String & Micro	29.33	06/07/2013
MRIGlobal	Polycrystalline	Sunverge	10.56	05/16/2013
UMKC Flarsheim Hall	Polycrystalline	Sunverge	4.32	08/18/2013
UMKC Student Union	Polycrystalline	String	5.28	08/18/2013
Blue Hills	Polycrystalline	Micro	10.08	08/18/2013
KCMO Swope Park Office	Polycrystalline	Micro	10.00	12/31/2013
			176.90	

Figure 2-75: Typical Commercial PV Installation

2.2.5.4.1.1 Solar Panels [21]

Two industry-standard types of panels, monocrystalline and polycrystalline, were used throughout the SmartGrid installation area. The difference between monocrystalline solar cells are produced from a single crystal of silicon, while polycrystalline solar cells are produced from a piece of silicon consisting of many crystals. Since polycrystalline cells contain many crystals, they have a less perfect surface than monocrystalline, and thus absorb slightly less solar energy and produce slightly less electricity per square foot. On the plus side, the process of creating the silicon for a polycrystalline cell is much simpler, so these cells are generally cheaper per square foot. The cost of each type of panel per Watt of power output works out to be about the same, but polycrystalline panels are slightly larger than equivalent monocrystalline panels.

2.2.5.4.1.2 Racking Systems [21]

The “Evolution” series racking system, manufactured by DynoRaxx, was used for the solar installations. These racking systems are made from 100% fiberglass, which gives them a couple advantages over metal racking systems. First, the racks do not experience the same thermal expansion issues as traditional metal racking systems do, which can cause key connection points in the system to loosen and fail. Also, traditional metal racking systems can damage unprotected rood surfaces. With the DynoRaxx, KCP&L felt confident that the customer’s property would be protected for the life of the system.

2.2.5.4.1.3 Inverters [21]

Three different types of inverters were used for installations in this project:

- Micro Inverters – Micro inverters produce grid-matching power directly at the back of the panel. Arrays of panels are connected in parallel to each other and fed to the grid. This has the major advantage that a single failing panel or inverter will not take the entire string offline. The Enphase M215 Micro Inverters and associated cables and Enphase Envoy monitoring system were installed at Blue Hills Community Center.
- Sunverge Inverter – The Sunverge Solar Integration System (SIS) is a PV array and battery. It is an intelligent communication platform through which utilities can send messages, tips, instructional demand responses and load management messages to their customers. Sunverge Integration Systems were installed at Project Living Proof, MRIGlobal, and UMKC’s Flarsheim Hall.
- String Inverters – In a grid-tied system, the solar panels are wired together in series (a “string” of panels) which increases the voltage and keeps the current low so that wiring is simpler and wire size can be smaller. String inverters were installed at Project Living Proof, Paseo High School, Innovation Park, and the UMKC Student Union.

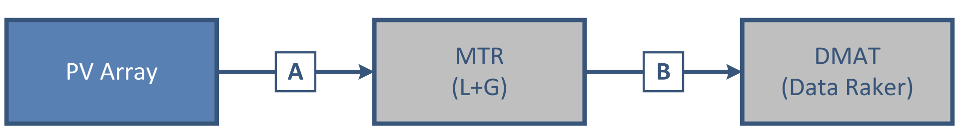
2.2.5.4.1.4 Data Mining and Analysis Tool

Each of the solar PV systems is connected directly to the grid through an AMI meter. The kWh generated and consumed by the system is captured in 15-minute interval data and sent to KCP&L’s Data Mining and Analysis Tool. DMAT provides the ability to display and download the data for analysis.

2.2.5.4.2 Integration

An overview of system-to-system interfaces relevant to the PV array is illustrated in Figure 2-76.

Figure 2-76: KCP&L SmartGrid Demonstration Project PV Integration



Recording the Solar PV energy production requires minimal system-to-system and system-to-device interfaces. These integration touch points are as follows:

A. All PV arrays are direct grid-connected with independent utility revenue-grade metering. The PV arrays don't send messages to the Meter (MTR); rather, they are connected to the meter, so the meter simply reads the received contributions from solar.
B. '15 Minute Interval Data' sent from the MTR to the DMAT for use in reporting. The aggregated totals in these data feeds are broken down into received (what solar provides) and delivered (what the customer uses).

2.2.5.4.3 Post-Implementation Operational Issues

Following the installation of the solar PV systems, several post-implementation operational issues needed to be mitigated and considered. These issues are as follows:

- Net meters were installed on the grid connected PV so that the project team could measure both the energy produced by and energy consumed by the PV inverter. Due to the different physical electrical wiring connections, the energy delivered and received as recorded by the net meters was not consistent across all installations. This required additional tracking to ensure that meter data was interpreted correctly.
- Differences in terminology between Generation and Retail metering standards added to the confusion identified in the previous point. For generation metering "energy delivered" is energy delivered from the generator to the transmission grid. For retail tariffs "energy delivered" is energy delivered to the customer and "energy received" is energy received from the customer.
- As with any trial program, there is and will continue to be internal debate over which department should be responsible for PV system maintenance issues as they occur. So far, very few PV maintenance issues have occurred.
- On several occasions the AMI meters had stopped recording PV production and the project team only discovered them during the monthly reporting process. These have typically been due to meter vandalism, but one was due to copper theft. With the enterprise MDM deployment, KCP&L plans to implement alerts that will notify metering personnel when PV generation is not being recorded.

2.2.5.4.4 Lessons Learned

Throughout the build, implementation, and daily operation of the solar PV arrays, several considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- Evaluating suitability of existing building rooftops for long term lease arrangement was time consuming. Many evaluated did not have the structural integrity required or would have required considerable maintenance before a PV array could be installed.
- The project team structured the lease arrangement with a single upfront payment of $750/kW to incent customers, help defray any structural or roof repairs they may be required to perform, and to avoid long term KCP&L administrative costs. However, the upfront payment did not provide the incentive desired.
- Developing a Rooftop Lease and negotiating the terms of the Lease was very difficult. After long deliberations with legal staff on to potential mortgage issues that a lease of the rooftop may create, KCP&L decided to only pursue leases on building where the owner had clear title. With this constraint, the project team had to focus on buildings owned by the city, university, schools, and large corporations. Unfortunately, they each had legal staffs that had to negotiate the terms of the lease with KCP&L corporate legal staff. This proved to be a very time consuming process.

- A company metering standard for utility owned, grid connected distributed generation should be established that is consistent with retail net metering standards and terminology.

2.2.5.5 Vehicle Charge Management System

The Vehicle Charge Management System deployed an integrated network of electric vehicle charging stations for the SGDP. The VCMS and Electric Vehicle Charging Stations (EVCSs) provide customers with the convenience of public charging, while also providing KCP&L with further demand response resources and capabilities.

2.2.5.5.1 Build

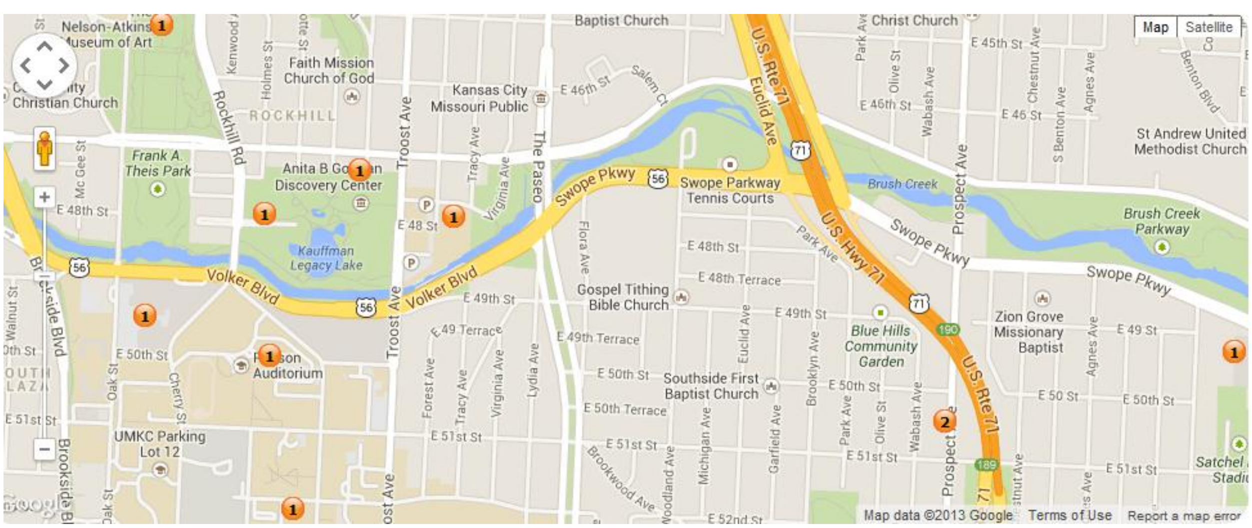
A total of ten EVCSs have been deployed during this implementation. Supply and installation of the EVCSs was managed by LilyPad EV. Each EVCS consists of a dual port, level 2 (240V) Coulomb CT2021 Charging Station with SAE J1772 standard connectors. Each EVCS is equipped with a cellular modem enabling two-way communications with the ChargePoint web platform. This allows electric vehicle owners to locate and reserve individual EVCS using web mapping applications. These charging stations are free for electric vehicle owners to use.

KCP&L monitors and manages each EVCS via the ChargePoint web platform as well. Station summaries, including usage and inventory reports, reservation schedules, and audit reports, are readily available through the platform. KCP&L is also able to manage access control, station provisioning, station alarms, and peak load configurations.

The EVCS locations are:

- Demonstration House
- Midtown Substation
- Midwest Research Institute
- Nelson-Atkins Museum of Art
- UMKC – University Center
- UMKC – Chemical Lab
- Blue Hills Community Center – 2 stations
- Kauffman Foundation
- City of KCMO – Swope Pkwy

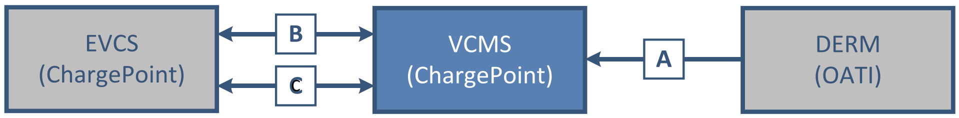
Figure 2-77: ChargePoint Map of SmartGrid EVCSs



2.2.5.5.2 Integration

An overview of system-to-system interfaces relevant to VCMS and applicable messages is illustrated in Figure 2-78.

Figure 2-78: KCP&L SmartGrid Demonstration Project VCMS Integration



The Vehicle Charge Management System is a fairly independent backend system, communicating with only one other "system" – the DERM. The VCMS also communicates with all ten EVCSs. These interfaces are summarized as follows:

A. Demand Response Event request initiated from DERM to VCMS. These messages are sent via the Internet (not through KCP&L's ESB, like most of the other vendor-to-vendor communications), and they utilize ChargePoint's existing API. They are used to notify the VCMS of creation, modification, or cancellation of impending DR events to the charge station infrastructure.
B. Demand Response Event requests initiated from VCMS to the EVCS, and Charge Station Status messages about the real time status of charging stations sent from the EVCS to the VCMS for display on the ChargePoint GUI. Messages in this interface are passed via the Internet using the OpenCharge Protocol.
C. Charge Station Status and Usage data passed between the VCMS and the EVCS. The ChargePoint infrastructure is capable of communicating a variety of commands and status messages between individual charging stations and the VCMS. Some examples include usage data, network status, current charge/discharge status, messages for display on the station screens, and reservation information. Messages in this interface are passed via the Internet using the OpenCharge Protocol.

2.2.5.5.3 Post-Implementation Operational Issues

Following the installation of the Vehicle Charge Management System, several post-implementation operational issues needed to be mitigated and considered. These issues are as follows:

- Addressing EVCS operational issues often involved multiple parties from several organizations. Status alerts are sent to KCP&L from ChargePoint, KCP&L personnel must investigate to determine the nature of the issue and then follow-up actions are taken if needed. Any technical issues that arise with EVCSs are reported to LilyPad EV for resolution. LilyPad EV handles all equipment repairs and replacements. All non-equipment EVCS issues must be resolved between KCP&L and the EVCS hosting company.
- To facilitate the SGDP's "free" EVCS charging, KCP&L distributed special Charge Point Access Cards to EV owners upon their request. This eliminated the need for the EV owner to register a credit card with Charge Point, but did not allow them access to other Charge Point stations. This became an administrative burden, KCP&L now requires EV owners to obtain the ChargePoint Access Card directly from ChargePoint, allowing them to use the access card at any Charge Point charging station. The SGDP EVCSs can still be activated without an access card by the EV owner calling the ChargePoint Operations Center when connecting to the EVCS.

2.2.5.5.4 Lessons Learned

Throughout the build, implementation, and daily operation of the Vehicle Charge Management System, several considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- The SGDP EV charging program had to be developed within current legislative and commission constraints; 1) no tariff exists for KCP&L to sell (or give away) electricity at public charging stations, and 2)MO and KS do not allow resale of electricity by third parties. This required that the SGDP EV recruit businesses as charging station sponsors. As a charge station sponsor the business would provide the parking required for the EVCS and would allow the EVCS to be fed from their normal business electric service. The EV charging would be provided at no cost to the EV owner.
- EVCS under the program constraints outlined above made for very costly installations. The average cost to connect the EVCS to the customers electric service far exceeded initial expectations. Keep in mind, for a business the electric service is typically at the back of the building and parking is in the front. Due to the high installation costs, this may not be a viable business model for charge station deployment on a go forward basis.
- Location is a critical factor in determining EVCS usage. Highly visible, high-traffic areas such as museums, office buildings, and schools are more frequently utilized than some of the less accessible locations.
- Location is also a critical factor in determining EVCS utilization. Locations that generate multiple, moderate duration (1-2 hours) visits can have multiple charging sessions daily, providing the best overall EVCS utilization. Employee parking locations, while used daily, tend to only generate 1 or 2 charge sessions per day.
- Overall usage has increased since the project's first EVCSs were installed. Unfortunately, utilization of the project EVCSs has been fairly low compared to the Clean Cities EVCSs due to the low numbers of EVs in the vicinity of the project.

2.3 Implementation Testing Plans

Throughout the prior Implementation section, testing efforts were frequently mentioned in a cursory manner allowing the main focus to stay on the specific considerations for individual systems and integration points. However, as outlined in this section, a very robust and methodical testing approach was pursued to ensure that the implemented systems and interfaces worked as required to successfully demonstrate the scope of this initiative. While each system and interface had its own unique considerations, the philosophical approach was consistent and is elaborated upon here.

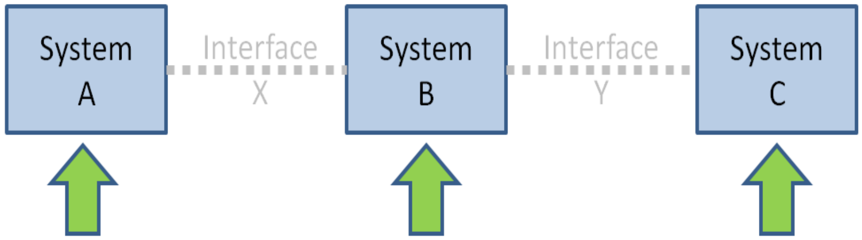
All testing efforts were governed by an overarching test strategy document produced early in project which articulated the general roles, responsibilities, and activities to be performed; it is included in Appendix H. To this end, testing was performed as an iterative approach progressing through the following incrementally higher levels of sophistication and will be further described in later sub-sections:

- System Testing – This stage of testing was focused on the individual, stand-alone systems to ensure their internal configurations and functions worked as required. This sub-section articulates considerations for environment setup and configuration, vendor co-located Factory Acceptance Testing, and Kansas City located Site Acceptance Testing. This sub-section concludes with an inventory of the subset of test books included in the appendix of this document; the subset corresponds to only those systems central to the interoperable focus of this initiative. Additional details to be discussed in Section 2.3.1.
- Integration Testing – This stage of testing was focused on the highly concentrated verification of communications between two individual systems and/or an individual system and integrated end-point devices; testing ensured that data is properly sent and received. This sub-section articulates considerations for environment setup and configuration, vendor co-located Factory Acceptance Testing, and Kansas City located Site Acceptance Testing. This sub-section concludes with an inventory of the subset of test books included in the appendix of this document; the subset corresponds to only those systems central to the interoperable focus of this initiative. Additional details to be discussed in Section 2.3.2.
- End-to-End Interoperability Testing – This stage of testing continues to build upon the earlier detailed testing and allows for verification of cross-system functionality throughout the ecosystem to ensure expected behavior at all points. This sub-section articulates the distinguishing characteristics of “Interoperability Testing”, defines the inventory of systematic data flows, and defines the structure of the interoperability test plans. This sub-section concludes with an inventory of the interoperability test plans included in the appendix. Additional details to be discussed in Section 2.3.3.
- End-to-End Field Demonstrations – This stage of testing allowed for the final verification of functionality and documentation of scripts which would be used to facilitate tours and demonstrations. This sub-section articulates the distinguishing characteristics of “Field Demonstrations”, defines the inventory of documented demonstration scripts, and defines the structure of the field demonstration script. This sub-section concludes with an inventory of the scripts included in the appendix. Additional details to be discussed in Section 2.3.4.

2.3.1 System Testing

System Testing involved testing of the individual, stand-alone systems prior to integration and interface testing. This ensured that the core system configurations and hard-coded capabilities were setup and working as expected. While not testing any of the integration points (which is covered in a subsequent phase of testing), system testing was primarily focused on User Interface (UI), internal algorithms, configurations and data models to verify that these were working to support the overall goals.

Figure 2-79: System Testing



This preliminary testing was vital to ensure that each system and its component functions were working in a stable and dependable manner. Establishment of this firm foundation minimized destabilizing variables in subsequent testing phases and allowed testing and remediation efforts to be focused only on the system without any complicating factors.

Testing efforts began with high-level planning to ensure that environments and staff were available and ready. While environment considerations are elaborated on below, staffing impacts were crucial from the beginning of planning efforts. By ensuring staff availability early on, they were able to participate in design workshops, configuration reviews, and training sessions to maximize their familiarity with the systems. To this end, system tests were handled as independent test efforts with different Subject Matter Experts (SMEs) assigned to different systems and functional capabilities as befitting their individual expertise. The highly skilled SMEs were responsible for the testing of each individual system and confirming adherence to requirements throughout various stages of detailed test planning activities (test script authoring), FAT, and SAT testing efforts.

System Testing activities were performed on every system comprising KCP&L's overall SmartGrid implementation. In this way, the formalized methodology and terminology outlined within this section can be read as an elaboration of the general testing efforts called out for individual systems throughout Section 2.2. However, whereas that section includes explicit segmentations of the implementation (particularly where multi-phase approaches were pursued), this section is more of an implicitly performed activity performed within those explicitly defined phases. Also, given the Interoperability objectives of the SGDP, some of the details and test book inventory in particular, have been filtered to only include detailed descriptions for system testing which enabled 61968, OpenADR, and ZigBee capabilities.

2.3.1.1 Environments

Environments represent a collection of end-point devices and servers that host systems which are isolated in one way or another to enable safe testing with minimal downside. While the environment itself may be isolated and/or partitioned, the numerous systems within an environment can and eventually are connected to one another to enable advanced testing. However, for purposes of individual System Tests at KCP&L, very few of the interfaces were required which allowed preliminary System Testing to be performed in parallel with integration implementation (which in turn would be tested in a subsequent effort).

For KCP&L's implementation, there were two main types of environmental considerations applicable to System Testing: 1) Vendor-Hosted vs. Internally-Hosted Systems and 2) Environment Delineation and Code Promotion. These are explored in greater detail in the following sub-sections:

2.3.1.1.1 Vendor-Hosted vs. Internally-Hosted Systems

All systems for this implementation fall into one of the two following buckets. The specific status of each individual system are documented in their respective implementation descriptions in Section 2.2.

- Vendor-Hosted – This server hardware was owned and operated by vendors. The vendor had responsibility to perform all hardware and software maintenance at their facilities. The vendor was also responsible for all software upgrades and supported KCP&L as necessary to ensure sufficient integration access was established. As defects were identified, the vendor remediated and applied to their servers in coordination with KCP&L.
- Internally-Hosted – This hardware was owned and operated by KCP&L. Servers for internally hosted Systems were procured by KCP&L and configured with standard KCP&L enterprise software (e.g. virus scanning, etc.). This hardware was ultimately sited at KCP&L facilities. As a result, whenever software changes were delivered, it was KCP&L's responsibility to install software to servers.

2.3.1.1.2 Environment Delineation & Code Promotion

At incremental points of the systems development lifecycle, different environments were used as a means to isolate software advanced to different levels of maturity and stability. Each incremental environment had additional capabilities in terms of input and output data types.

2.3.1.1.2.1 DEVELOPMENT/SUPPORT ENVIRONMENTS

These servers were initially used by vendors for development, configuration, and pre-testing activities. At early stages of development, several systems in these environments were originally sited at vendor facilities for preliminary configuration even if they were not destined for a vendor-hosted configuration. These system environments are primarily used to ensure that minimal levels of functionality were working in tightly controlled conditions allowing vendors to make significant advancements independently.

Configuration and test executions were performed by vendors with the result that KCP&L end-users had very limited access to this environment - typically only in coordination with vendor staff. At later points in the product lifecycle, the development environment could remain independent, but its configurations would be synchronized with the demo environment allowing vendors to investigate issues that are discovered in the lab and demo environments (at which point the environment is generally considered the support environment). For systems destined for a vendor-hosted configuration, the vendor provided equipment was initially stood up to enable preliminary demonstration and testing. For systems destined for an internally-hosted configuration, KCP&L was responsible for hardware procurement and shipped the physical equipment to appropriate locations for initial configuration and setup.

2.3.1.1.2.2 LAB ENVIRONMENT

These servers were used in close coordination with development servers; as vendors stabilize modules of code, they promoted them into this environment where KCP&L end-users had significantly greater access. For systems destined for a vendor-hosted configuration, the vendor provided equipment was stabilized to enable incremental demonstration and testing. For systems destined for an internally-hosted configuration, KCP&L was responsible for hardware procurement and shipped the physical equipment to appropriate locations for initial configuration and setup; KCP&L staff then had remote access to the servers to test as needed. Note that internally-hosted lab servers may be remotely configured, before they were transitioned to KCP&L facilities during later integration testing. By establishing a distinction between lab and development, vendors were free to pursue solutions which could inadvertently break other functionality; by performing these actions in development, the lab environment can be used without fear of "tripping" over work that is still being worked.

2.3.1.1.2.3 DEMO ENVIRONMENT

These servers were the final point of the promotion path for compiled software and operated in a production context. Given that integration capabilities were minimal during System Testing, efforts continued to be focused on ensuring that the systems had appropriate user access permissions and stable execution of its core capabilities. These systems existed in parallel to the lab systems and were available for use simultaneously to the lab systems, but had different data to reflect their use as production systems.

Vendor-hosted demo systems remained at vendor sites but were implemented with end-state remote access capabilities. Internally-hosted demo systems were separate systems that were setup in parallel to lab systems. These servers and systems were ultimately integrated into the overall demo environment and were physically setup in secure locations. These systems were procured by KCP&L and had been setup to have similar configurations and settings as tested in the lab environment.

Tight controls were in place to ensure that any code promotions were socialized and approved by pertinent parties. Whenever new functionality was deployed into this environment, preliminary testing was performed to ensure that it was working in the new environment and that no new defects had been introduced due to nuances of the environment. KCP&L end-users had access to the systems based on prescribed system access permissions; caution was used when performing operations in these systems because they would ultimately be integrated with other systems and devices that would have real-world implications. Also since this was a production environment, habits needed to be established to engage and coordinate with DSO and field crews as necessary to ensure safe operating conditions.

2.3.1.2 Factory Acceptance Testing

This was the capstone activity to the main system development activities performed by the vendor. It was conducted at Vendor-based facilities and KCP&L testing team members travelled to the vendor site to perform the testing on the system. FAT was executed to demonstrate that the core capabilities were operational and that the system was ready to be migrated for more robust, KCP&L hands-on testing. As FAT was a prerequisite to installation on site, System FAT was done to ensure the system met the pre-set specifications and all functional requirements were met as specified in the design requirements. It was typical that testing activities would result in identification of functions that did not work as expected. In these cases, identified defects would be documented and prioritized for resolution (fixed immediately where possible).

FAT included both structured and unstructured testing to thoroughly test the base functionality of the custom systems and their sub-components. When executed, efforts were mainly performed by the vendor team, but the KCP&L testing team was involved at the vendor site to monitor the FAT activities, identify defects, and track them to resolution. Where possible, the vendor team endeavored to have major defects resolved at the vendor site and during the FAT activities. Changes and fixes could be installed easily at the vendor site rather than at KCP&L where the constraints would increase (involving KCP&L change control and diminished familiarity with installation protocols). The two main stages to FAT were as follows:

2.3.1.2.1 System Factory Acceptance Test Planning

Prior to the KCP&L System FAT teams traveling to vendor facilities, significant efforts were conducted in advance to ensure maximum effectiveness while onsite. These activities included:

- Standard Test Book Reviews – Standard test books were created and available from vendors for their products. These were provided to KCP&L in the early stages of the project for planning purposes. Standard test books were reviewed by the test team to ensure the tests were comprehensive and that the detailed steps are logical.

- Test Book Customization – In some cases, the test team determined that some functionality was not required and removed those functional tests. Alternatively, the test team determined other cases where the standard test book was insufficient and that greater testing was required. In these cases, additional test cases and steps were drafted and included into the test book. The customized test books were then shared with the vendor to ensure agreement on the scope of the test execution effort.

2.3.1.2.2 System Factory Acceptance Test Execution

Based on the preparations directly above, the KCP&L System FAT teams began efforts to review the functionality as configured:

- Pre-FAT Execution – As vendors concluded their initial configuration efforts in the development environments, they began comparing the implemented functionality against the tests documented in the test book. Many of these efforts were performed independently by the vendor, but in preparation for FAT execution some of these tests were monitored by the KCP&L testing teams. Upon successful demonstration of preliminary functionality, the system code and configurations were migrated out of the development and into lab where it was ready for formalized FAT execution.
- Structured Testing – Once the vendors were sufficiently confident of their system's configuration, the KCP&L team traveled to the vendor facility to jointly work through the documented test book and verify that it was working as expected in the lab environment. This portion of testing was primarily performed by the vendors with KCP&L staff monitoring the system performance. Much of this activity strictly adhered to the steps outlined in the test book documentation.
- Unstructured Testing – Conducted in parallel with structured testing, this effort was somewhat more vague in that it allowed the testing team to be creative and test functionality in ways not exactly documented to see how the system performed. Similar to the structured testing, the vendor performed the actions necessary in response to questions asked by KCP&L to see certain functionality. This was done because some of these tests were not possible to consider in advance due to a lack of understanding of system capabilities.
- Variance Documentation – Throughout the FAT execution, there were numerous functional items that did not perform within tolerances. These variances were documented and tracked to help increase the stability and functional capabilities of the system. Once a sufficient number of variances were resolved, the system was ready to be migrated out of the lab environment into the demo environment for System SAT.

2.3.1.3 Site Acceptance Testing

This was the first step to deploying the systems for real-world use. It was used to demonstrate that the core capabilities verified in the controlled vendor environments continued to work in end-state environments. The system had already gone through FAT, but the relocation of the system and installation in a new environment and the additional nuances of real world connectivity (as compared to a more simulated environment at the vendor site) introduced new complexities and challenges into the system. The system must be further tested on site to ensure that the design specifications were met and that the system was ready to be fully integrated and ready for further exhaustive integration testing.

SAT followed a similar structure to FAT but additionally confirming that the system is stable at the KCP&L site with the real world data and complexities. Similarly, it was composed of structured and unstructured testing. The KCP&L testing team performed SAT activities completely autonomously, with occasional support from the vendors. The two main stages to SAT were as follows:

2.3.1.3.1 System Site Acceptance Test Planning

Prior to the KCP&L System SAT teams beginning onsite testing, significant efforts were conducted in advance to ensure maximum effectiveness. These activities included:

- Standard Test Book Reviews – Standard test books were created and available from vendors for their products. These were provided to KCP&L in the early stages of the project for planning purposes. Standard test books were reviewed by the test team to ensure the tests were comprehensive and that the detailed steps are logical. These books were very similar to the test books used during FAT.
- Test Book Customization – In some cases, the test team determined that some functionality was not required and removed those functional tests. Alternatively, the test team determined other cases where the standard test book was insufficient and that greater testing was required. In these cases, additional test cases and steps were drafted and included into the test book. The customized test books were then shared with the vendor to ensure agreement on the scope of the test execution effort. In addition, the test team will begin to identify test data and scenarios that can be applied to the finalized test cases.

2.3.1.3.2 System Site Acceptance Test Execution

Based on the preparations directly above, the KCP&L System SAT teams began efforts to review the functionality as configured

- Pre-SAT Execution – As the systems were prepared for SAT testing, changes were implemented in the demo environments. Vendors began shifting their vendor-hosted configurations to demo environments. KCP&L IT began receiving internally-hosted hardware and installing as necessary. Where possible and ready, the systems were also migrated into the demo environments. In all cases, systems were established and stabilized. Systems were reviewed by the test team on a daily basis to ensure stability and readiness for more robust testing.
- Structured Testing – As the system stabilized, the KCP&L team began conducting tests from the documented test book and verified that it was working as expected in the demo environment. This portion of testing strictly adheres to the steps outlined in the documentation.
- Unstructured Testing – Conducted in parallel with Structured testing, this effort was somewhat more vague in that it allowed the testing team to be inspired and test functionality in ways not exactly documented to see how the system performed. This was done because some of these tests were not possible to consider in advance due to a lack of understanding of system capabilities.
- Variance Documentation – Throughout the SAT execution, there were numerous functional items that did not perform within tolerances. These variances were documented and tracked to help increase the stability and functional capabilities of the system. Once a sufficient number of variances had been resolved, the system is ready for additional levels of testing (e.g. Integration, Interoperability, Demonstration).

2.3.1.4 Details

As mentioned in the beginning of this section, System Testing was performed for all systems. As such, a test book was created and executed for each system. However, given the SGDP's focus on 61968, OpenADR, and ZigBee capabilities, only a subset of test books are being included for reference as part of this report. Table 2-14 lists the functional area and specific system test books which have been included in Appendix I. However, they are not the exact test books from the project and instead are a standardized iteration for purposes of this report to highlight the capabilities and testing objectives. In many cases, the actual test books included individual test steps on the specific systems and in some cases, included proprietary or confidential vendor information about their system's internal functionality.

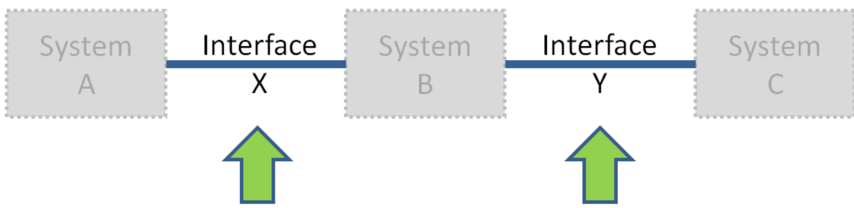
Table 2-14: System Test Books

Functional Area	System	Appendix I: Sub-Appendix Location
Smart Substation	Substation HMI	I.1.1 HMI.FAT I.1.2 HMI.SAT
Smart Substation	SICAM	I.1.3 SICAM.FAT I.1.4 SICAM.SAT
Smart Substation	DCADA	I.1.5 DCADA.P3FAT I.1.6 DCADA.P3SAT
Smart Distribution	DMS	I.1.7 DMS.P1FAT I.1.8 DMS.P1SAT.P2P.SUB I.1.9 DMS.P2FAT.REDUNDANCY I.1.10 DMS.P2FAT.UI I.1.11 DMS.P2SAT.P2P.CB I.1.12 DMS.P2SAT.P2P.FCI I.1.13 DMS.P2SAT.REDUNDANCY I.1.14 DMS.P2SAT.UI I.1.15 DMS.P3FAT.651R I.1.16 DMS.P3FAT.CDNA I.1.17 DMS.P3FAT.RTAC (BATTERY) I.1.18 DMS.P3SAT.CDNA I.1.19 DMS.P3SAT.P2P.651R
Smart Distribution	HIS	I.1.20 HIS.P3SAT
Smart Generation	DERM	I.1.21 DERM
Smart Metering	MDM	I.1.22 MDM
Smart Metering	AHE	I.1.23 AHE (Core) I.1.24 AHE (Meter Test)
Smart End-Use	HEMP	I.1.25 HEMP
Smart End-Use	HAN	I.1.26 HAN I.1.27 HAN (Additional Tests)

2.3.2 Integration Testing

Integration Testing involved testing of the individual connections between stand-alone systems to ensure accurate preliminary communications. This ensured that the core communications configurations and enabling functions were setup and working as expected. While not testing any comprehensive, end-to-end connectivity (which is covered in a subsequent phase of testing), integration testing was primarily focused on data transmission, data translation, data receipt, firewall configuration, and Message Queue (MQ) configuration to verify that these were working to support the overall goals. This testing consumed a considerable amount of project work due to the complexities between systems and the focus on quality which ensured the operation in a stable and dependable manner. Establishment of this solid communications framework minimized destabilizing variables in subsequent testing phases and allowed testing and remediation efforts to be focused only on the integration without any complicating factors.

Figure 2-80: Integration Testing



Testing efforts began with high-level planning to ensure that environments and staff were available and ready. While environment considerations are elaborated on below, staffing impacts were crucial from the beginning of planning efforts. By ensuring staff availability early on, they were able to participate in design workshops, configuration reviews, and training sessions to maximize their familiarity with the interface functions. To this end, integration tests were handled as independent test efforts with different Subject Matter Experts (SMEs) assigned to different systems and integration capabilities as befitting their individual expertise. The highly skilled SMEs were responsible for the testing of each individual integration point and confirming adherence to requirements throughout various stages of detailed test planning activities (test script authoring), FAT and SAT testing efforts.

Integration Testing activities were performed on every interface connecting the various systems of KCP&L's overall SmartGrid implementation. In this way, the formalized methodology and terminology outlined within this section can be read as an elaboration of the general testing efforts called out for individual systems throughout Section 2.2. However, whereas that section includes explicit segmentations of the implementation (particularly where multi-phase approaches were pursued), this section is more of an implicitly performed activity performed within those explicitly defined phases. Also, given the Interoperability objectives of the SGDP, some of the details and test book inventory in particular, have been filtered to only include detailed descriptions for system testing which enabled 61968, OpenADR, and ZigBee capabilities.

2.3.2.1 Environment

Environments represent a collection of end-point devices and servers that host systems which are isolated in one way or another to enable safe testing with minimal downside. In earlier testing efforts (particularly System Testing), the environments themselves are isolated and/or partitioned, but the systems within an environment are also autonomous. At this stage of testing, the environments remain independent, but the systems within were connected to one another to comprise a more comprehensive, integrated entity enabling advanced testing. However, for purposes of individual System Tests at KCP&L, very few of the interfaces were required which allowed preliminary System

Testing to be performed in parallel with integration implementation (which in turn would be tested in a subsequent effort).

For KCP&L's implementation, there were three main types of environmental considerations applicable to System Testing: 1) Enterprise Service Bus vs. Point-to-Point Integration, 2) Vendor-Hosted vs. Internally-Hosted Systems and 2) Environment Delineation and Code Promotion. While many of the high-level considerations from System Testing remain the same, they each have a different twist as applicable to integration testing. These are explored in greater detail in the following sub-sections:

2.3.2.1.1 Enterprise Service Bus vs. Point-to-Point Integration

All systems interfaces for this implementation fall into one of the two following buckets. Specific status of individual interfaces are outlined in Section 2.2, but reiterated as pertinent here.

- Enterprise Service Bus (ESB) – This hardware was owned and operated by KCP&L and acted as an intermediary layer of integration to ensure that data is properly transformed and made available to downstream systems. ESB capabilities were used more extensively for the interoperability functions leveraging 61968, OpenADR, and ZigBee standards. For many of these data exchanges, extra effort was pursued for the enhanced capabilities in this layer of exchange. As a result, extra dedicated testing was required to ensure that these data transformations were being properly performed.
- Point-to-Point – Other systems had integration requirements to enable certain functions, but as they were not central to the interoperability demonstration, the integration was not pursued along the ESB channel. In these cases, interfaces were developed allowing direct, point-to-point communications using proven web service and other proprietary capabilities to allow message transfers.

2.3.2.1.2 Vendor-Hosted vs. Internally-Hosted Systems

As mentioned in the system testing section, all systems are either internally-hosted or vendor-hosted. Keeping this in mind there are specific considerations applicable to integration testing with these different hosting situations.

- Vendor-Hosted – This hardware was owned and operated by vendors. For many of these systems interfacing with other vendor-hosted systems, significant effort was expended to route these communications through the ESB to the greatest extent possible. However, in certain circumstances, point-to-point functionality was required for expediency (particularly in scenarios not subject to Interoperability Testing). In all vendor-hosted situations, testing activities were highly coordinated with vendor development teams to ensure that data flows were working as expected. When integration improvements were required, the vendors directly implemented changes to the systems on their premises.
- Internally-Hosted – The hardware for these systems was owned and operated by KCP&L. To this end, the ESB itself was also an internally-hosted system. As with vendor-hosted systems, these systems could also leverage the ESB or point-to-point communications, but point-to-point was more common. Of particular note, testing efforts for these systems could be conducted with greater autonomy, but when integration defects were discovered, additional documentation and coordinated demonstrations became necessary to ensure that vendors providing remote support were properly able to verify the root cause of issues.

2.3.2.1.3 Environment Delineation & Code Promotion

At incremental points of the systems development lifecycle, different environments were used as a means to isolate integration capabilities advanced to different levels of maturity and stability. Each incremental environment has additional capabilities in terms of data volumes and validity.

2.3.2.1.3.1 DEVELOPMENT/SUPPORT ENVIRONMENTS

As mentioned in the Systems Testing section, the development environments were used by vendors for their initial configurations efforts. It was also used by KCP&L technologists for development/configuration and pre-testing activities. At early stages of development, all systems were originally supported at vendor facilities.

These development environments were mostly independent which resulted in testing integration capabilities leveraging special development harnesses, integration simulators, and manual payload inputs/outputs. The goal of these activities was to ensure that systems were able to appropriately handle core data exchange capabilities. As a result, certain interfaces destined for connectivity via the KCP&L-hosted ESB were not connected in this environment. Instead, simulators were used to ensure that the upstream and downstream systems were properly able to handle expected payloads.

These environments were primarily used to ensure that minimal levels of functionality were working in tightly controlled conditions allowing vendors to make significant advancements independently. To this end, configuration and test executions were performed by vendors. KCP&L end-users had very limited access to these environments; typically only in coordination with vendor staff. Upon preliminary confirmation of functionality by the vendor, any code or configuration changes were ready to be migrated to the lab environment.

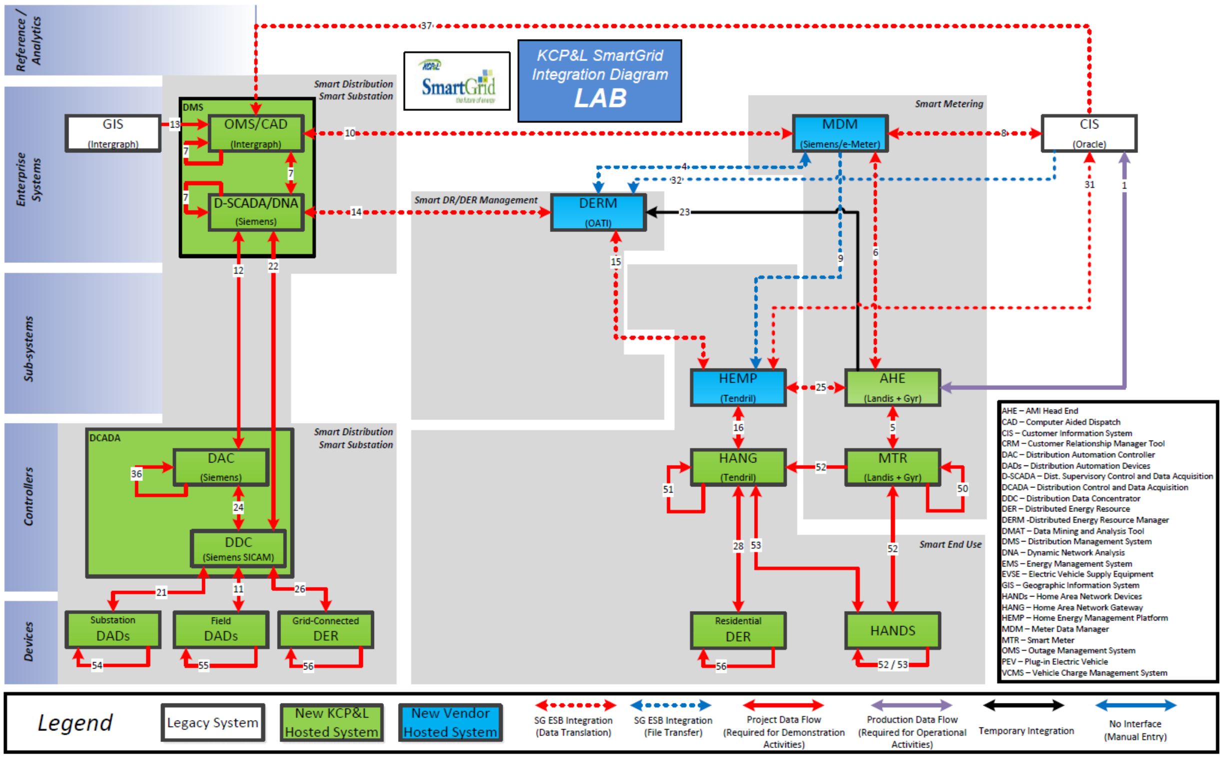
At later points in the product lifecycle, the development environment could remain independent, but its configurations were synchronized with the demo environment allowing vendors to investigate integration issues that were discovered in the lab and demo environments. At this point, this environment was generally considered the support environment.

2.3.2.1.3.2 LAB ENVIRONMENT

As mentioned in the System Testing section, the lab environment was next in the code promotion process. However, as described here in the Integration Testing section, the naming rationale for the lab becomes more appropriate for a number of reasons.

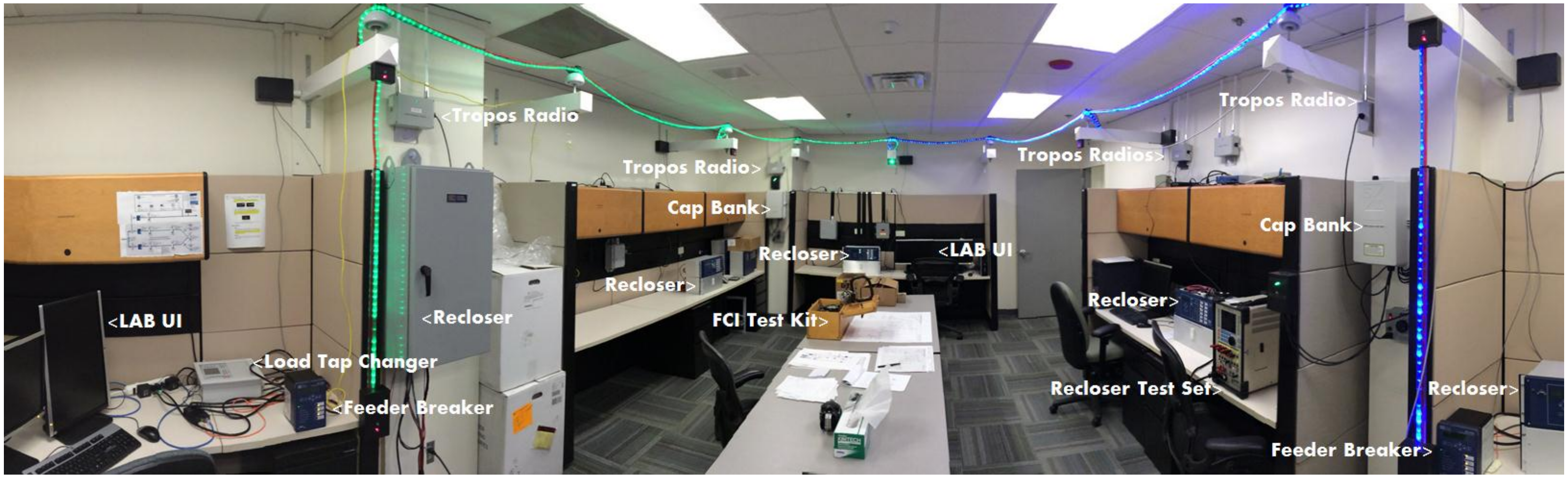
To start, this environment evolved to an integrated suite of systems allowing for the first instances of actual system to system communication. This subset of the entire end-state systems allowed for redundant testing capabilities of the most central interface pathways. Any vendor-hosted systems remained at vendor sites with preliminary integration capabilities to enable testing and when users access these systems, they do so remotely. internally-hosted systems used remotely for System Testing, continued to be use remotely though temporarily connected to devices in KCP&L's lab facility for preliminary testing. For more advanced testing, the servers were resent to KCP&L and were permanently integrated into the overall lab environment. In general, these servers and systems were then physically setup in secure locations next to their corresponding instances of demo hardware. This enabled KCP&L to have a physical and virtual replication of the demo environment to determine system capabilities, limitations, and other functional considerations. To this end, vendor-hosted and internally-hosted systems are integrated with each other via the ESB or point-to-point protocols as required. Firewall, VPNs, and other cyber security features are leveraged for tightly controlled communications and to provide a safe environment to ensure that these configuration approaches are ready for promotion to the demo environment. The integrated systems are shown in Figure 2-81.

Figure 2-81: SmartGrid Lab Environment Integrated Systems

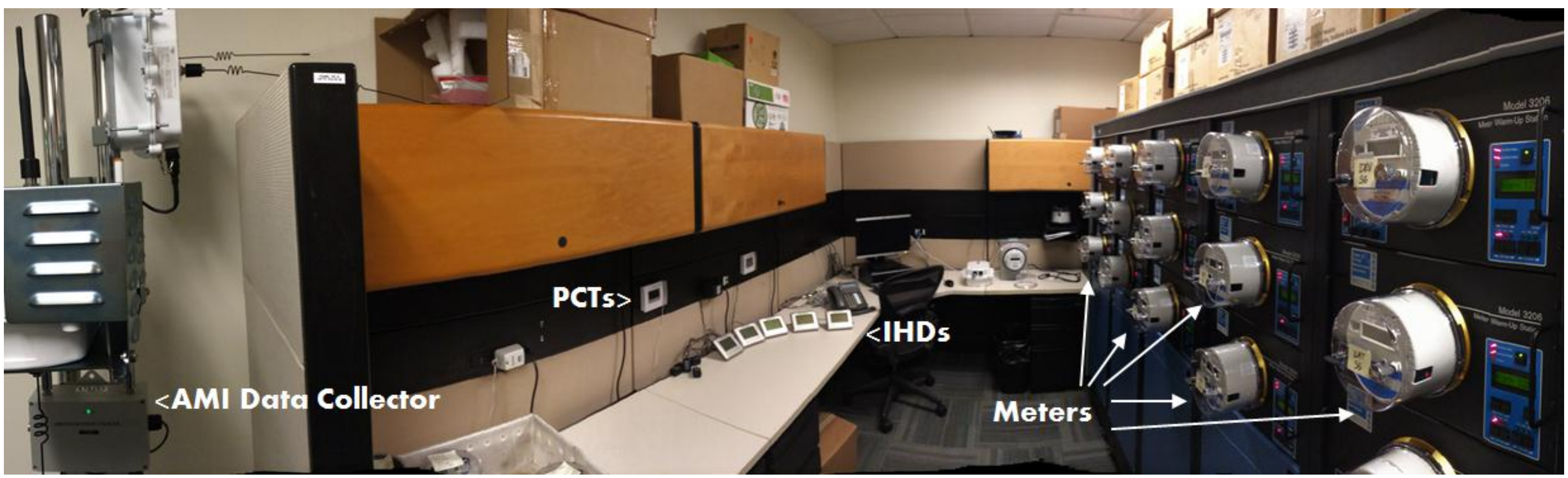


Furthermore, these systems are built around two physical laboratory rooms which were designed to include single instances or handfuls of end-use devices for DA and HAN testing capabilities. All systems and devices were integrated with each other to provide a safe area for testing.

The first lab room (below) was setup with substation and DA equipment logically representing two real-world circuits. For demonstration purposes these circuits were represented by a dynamically interactive "light show" which could tangibly represent outages and sectionalizations being simulated in the systems.

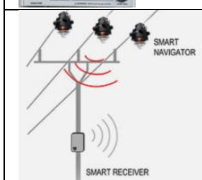


The second lab room (below) was setup with AMI and HAN as a representation of end-use residential and commercial customers in the real world.



In all, the physical lab included quite a few devices which were very important to KCP&L's ability to progress integration testing. Through the use of these numerous physical devices, in conjunction with their directly associated parent systems, the lab environment was used for initial KCP&L verification of newly delivered capabilities. In addition, it also served as a means to retest variance fixes to core systems prior to implementation in the demo environment. Table 2-15 outlines the full inventory of all devices deployed for use in the lab environment.

Table 2-15: Devices Deployed in Lab Environment

Device Type	Device Details		Count
Substation Protection Network Devices		SEL 751A Feeder Breaker	2
		Eberle REG-DA Load Tap Changer (LTC)	1
Distribution Automation (DA) Devices		S&C Cap Bank Controllers	2
		Horstmann Fault Current Indicator (FCI) Receiver and paired set of FCIs	1 "Family"
		SEL 651R Recloser Controllers	5
		SEL RTAC Battery Controller	1
Field Area Network (FAN) Devices		Tropos 1310 – Edge Router	5
		Tropos 6320 – Gateway Router	1
Smart Meters		L+G AMI Meter	15
Home Area Network (HAN) Devices		Tendril Programmable Controllable Thermostat (PCT)	5
		Tendril In-Home Display (IHD)	5

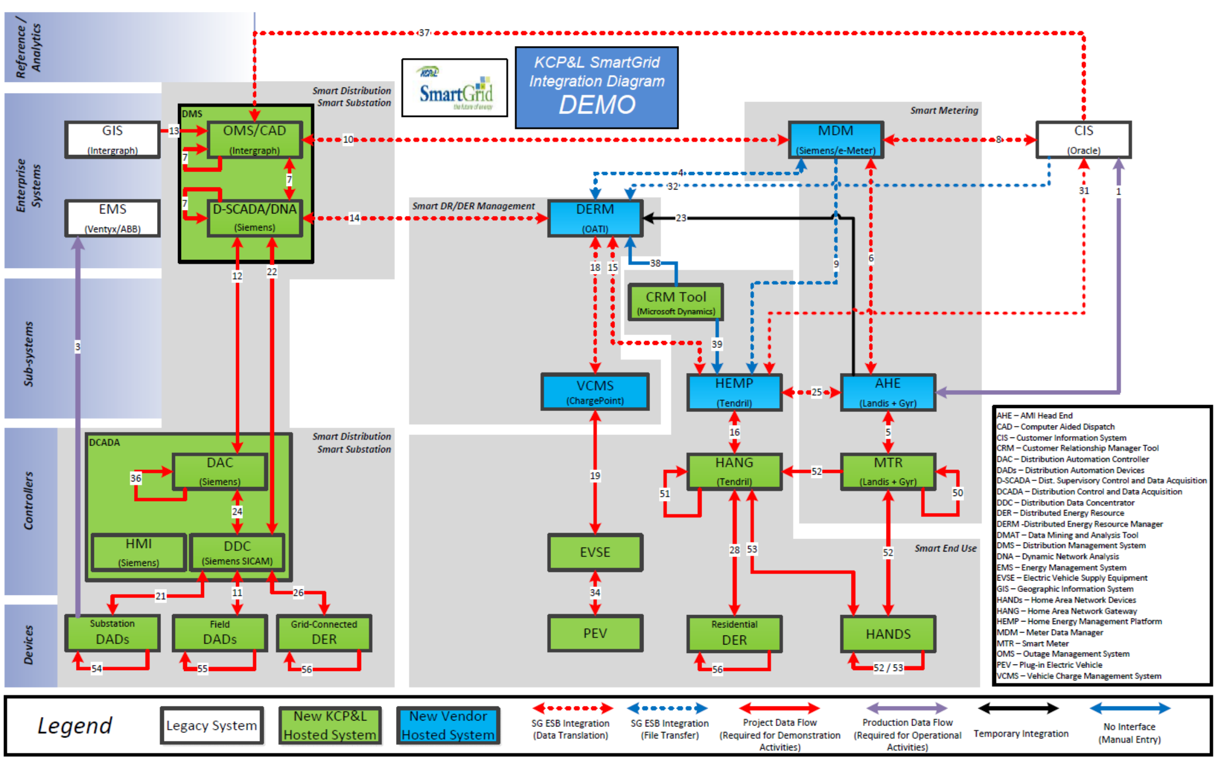
In general, lab represented a controlled environment in which very specific test cases were conducted. Furthermore, it allowed users to establish an initial comfort level with newly delivered integration capabilities and variance fixes allowing for sandbox testing of communications between systems. This environment didn't impact any end-use customers and represented a safe zone to test out scenarios for any functionality to be promoted to the demo environment. This was the first time in the environment promotion pathway where KCP&L end-users had significant access to navigate the system and test its capabilities.

2.3.2.1.3.3 DEMO ENVIRONMENT

As mentioned in the System Testing section, the demo environment was the final environment of the code promotion process. Just as with the lab environment, this environment also evolved from a collection of stand-alone systems. However, whereas the lab evolved to establish communications with lab devices, as an integrated suite of systems demo evolved to allow for system-to-system and system-to-real-world-device communication. As such, extreme care was taken while executing tests in this environment as they would have real-world impacts in many instances of use.

Any vendor-hosted systems remained at vendor sites with preliminary integration capabilities to enable testing; when users access these systems, they do so remotely. Internally-hosted systems were initially setup during System Testing but were now ready to be configured for communication with other systems. To this end, vendor-hosted and internally-hosted systems were integrated with each other via the ESB or point-to-point protocols as required. Firewall, VPNs, and other cyber-security features were leveraged for tightly controlled communications to provide a safe environment for communications. The integrated systems are shown in Figure 2-82.

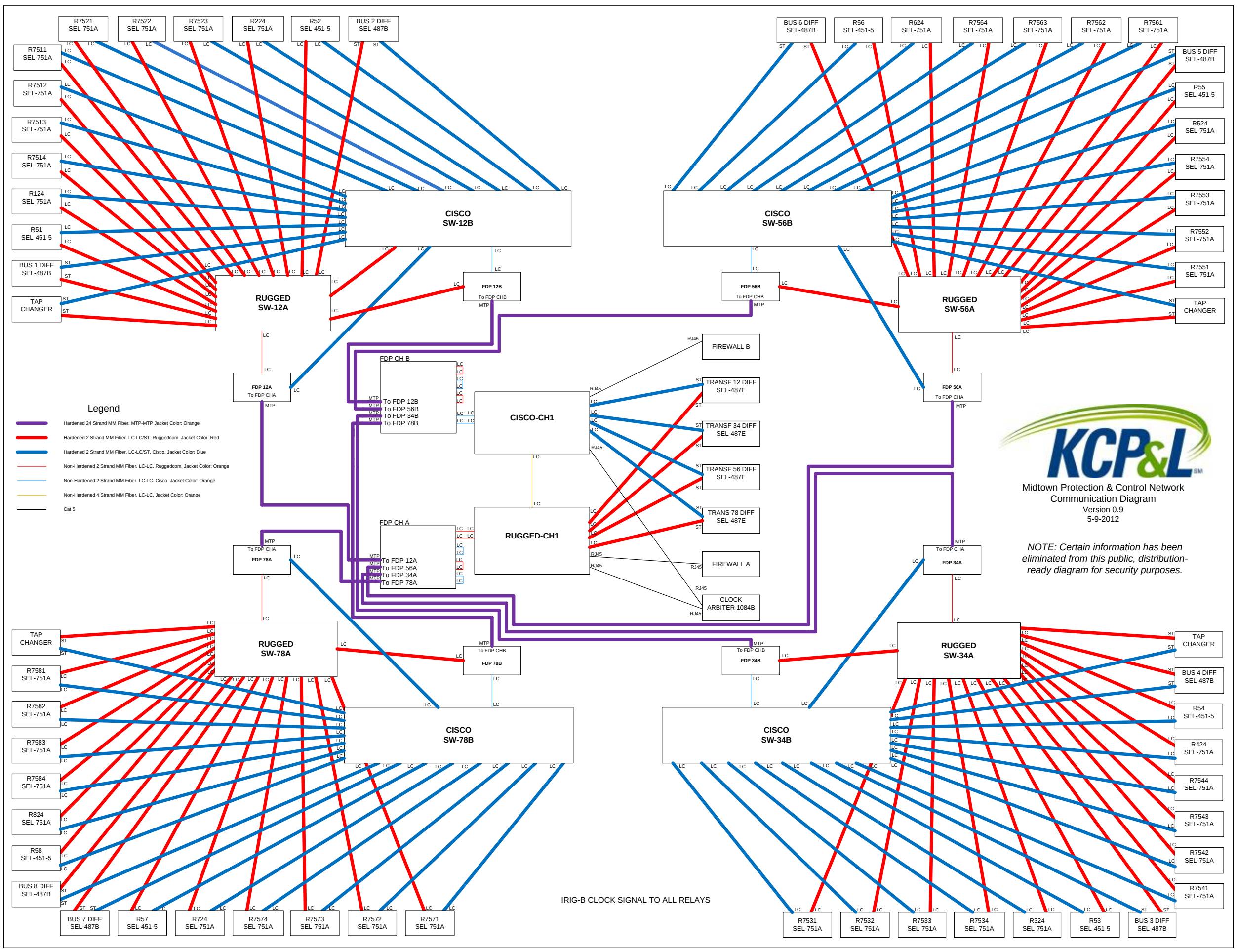
Figure 2-82: SmartGrid Demo Environment Integrated Systems



Furthermore, in order for these systems to be fully tested in preparation for real-world use in this environment, it was absolutely imperative that they were able to communicate with various real world devices in addition to communicating between systems. Unlike the lab environment, demo had significantly more devices which required deployment in real-world conditions. There were three main settings in which devices were deployed for the demo environment: Midtown Substation, Highly-Automated Circuits, and Smart-End Use Program Participant Residences.

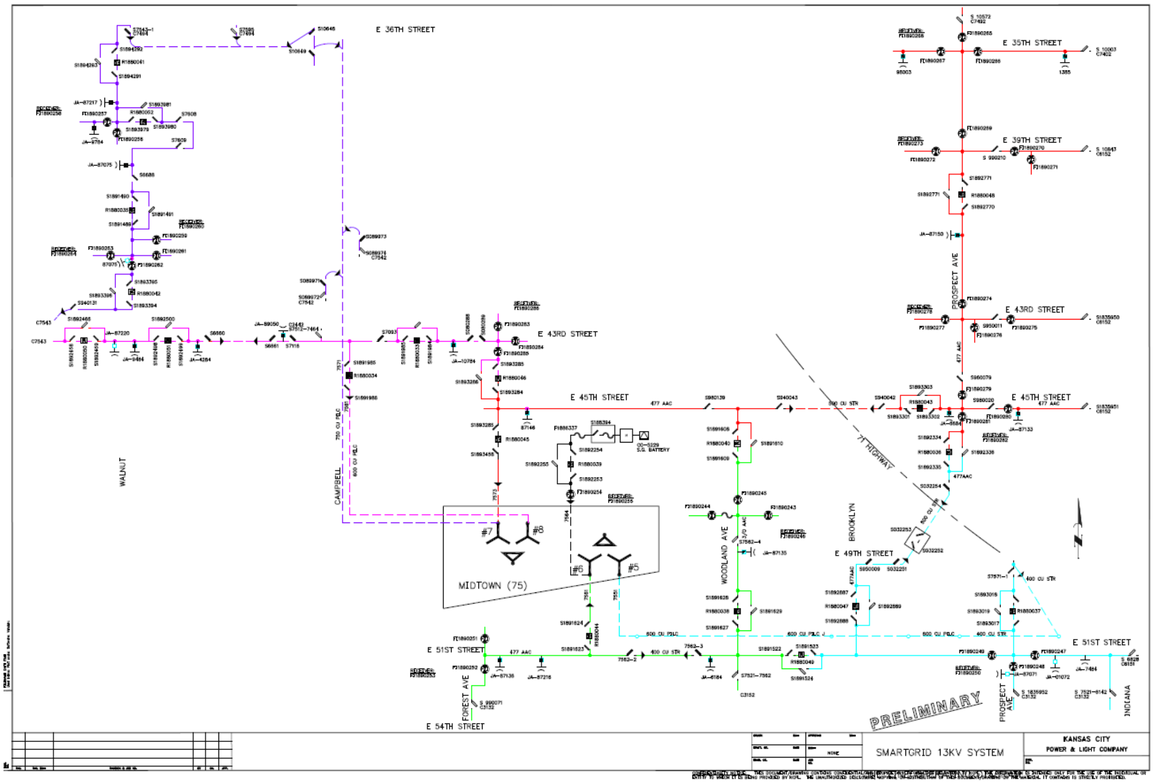
The first setting was KCP&L's Midtown Substation. With the entire substation affected, significant coordination was required with various operations groups to ensure minimal disruption to customers and a safe operating environment for crews to deploy and connect the devices. The scope of the deployment is shown in Figure 2-83.

Figure 2-83: Midtown Substation



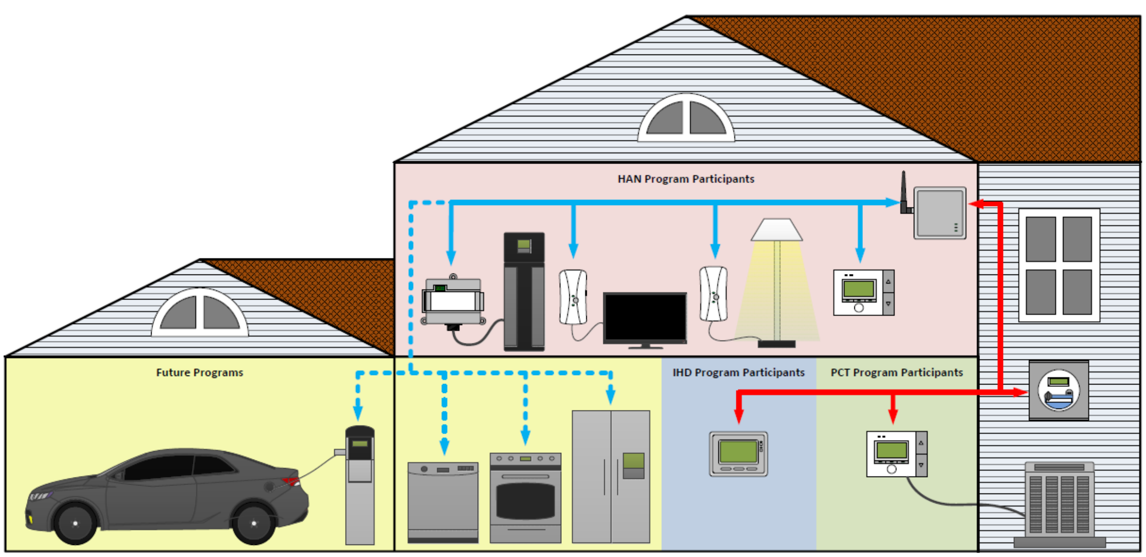
The second setting was a collection of six of KCP&L's real-world highly-automated distribution feeders radiating from the Midtown Substation. As shown in the one-line diagram in Figure 2-84, circuits were chosen in such a way that various reclosers, capacitor banks, and FCIs could work together to demonstrate the results of the DMS algorithms such as Volt/VAR Control (VVC), Fault Location (FLOC), Feeder Load Transfer (FLT), and Fault Isolation and Service Restoration (FISR).

Figure 2-84: Midtown Substation and Distribution Feeders



The third setting was a much larger collection of various KCP&L's customers who opted to participate in one of the available Smart End-Use programs. These programs comprised the In-Home Display Program, Programmable Controllable Thermostat Program, and the Home Area Network Program. Due to the relatively large number of participants in these programs, a representative diagram for the entire deployment is not feasible for this section, but Figure 2-85 does represent the scope of each of these programs to some degree. The full scope of this deployment should be appropriately considered when contemplating the overall scale of this environment.

Figure 2-85: SmartEnd-Use Home Configuration



In all, the physical device deployments in each setting were very important to KCP&L's ability to progress integration testing in the demo environment. Through the use of these numerous physical devices, in conjunction with their directly associated parent systems, the demo environment was the final point in the promotion pathway and used for final KCP&L verification of operational capabilities. Table 2-16 outlines the full inventory of all devices deployed for use in the demo environment.

Table 2-16: Devices Deployed in Demo Environment

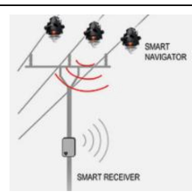
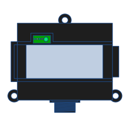
Device Type	Device Details		Count
Substation Protection Network Devices		SEL 451-5 Main Breaker	8
		SEL 487B Bus Differential	8
		SEL 487E Transformer Differential	4
		SEL 751A Feeder Breaker	31
		SEL 751A Tie Breakers	8
		Eberle REG-DA Load Tap Changer	4
Distribution Automation (DA) Devices		SEL 651R Controllers & paired Siemens Reclosers	10 Pairs
		SEL 651R Controllers & paired G&W Reclosers	10 Pairs
		S&C Cap Bank Controllers & paired S&C IntelliCAP+ Capacitor Banks	29 Pairs
		Horstmann Fault Current Indicator (FCI) Receivers and paired sets of FCIs	12 "Families"

Table 2-16: Devices Deployed in Demo Environment (Continued)

Device Type	Device Details		Count
Distributed Energy Storage		SEL RTAC Battery Controller S&C SMS Battery Inverter Exergonix DESS CS1000	1 Set
Field Area Network (FAN) Devices		Tropos 1310 – Edge Router (Radios connected to DA Devices)	62
		Tropos 6320 – Base Router (Radios establishing back-bone communications)	43
Smart Meters		L+G AMI Meter – Residential	12,188
		L+G AMI Meter – Commercial	1,245
Home Area Network (HAN) Devices		Tendril Home Area Network Gateway (HANG)	59
		Tendril Programmable Controllable Thermostat (PCT)	109
		Tendril In-Home Display (IHD)	625
		Tendril Volt	117
		Tendril Load Control Switch (LCS)	12
PEV Charging Stations		ChargePoint Electric Vehicle Charging Station	9

In general, demo represented the least controlled environment in that it contained the most number of real-world complicating variables. As this environment impacted end-use customers, tight controls were in place to ensure that any code promotions are socialized and approved by pertinent parties prior to installation to the demo servers. Whenever new functionality was deployed into this environment, preliminary testing was performed to ensure that it was working in the new environment and that no new defects had been introduced due to nuances of the environment. KCP&L end-users had access to the systems based on prescribed system access permissions; caution was used when performing operations between these systems because they could result in real-world operations. Also since this was a production environment care needed to be taken to engage and coordinate with DSO and field crews as necessary to ensure safe operating conditions.

2.3.2.2 Factory Acceptance Testing

This was the capstone activity to the main integration development activities performed by the vendor. It was conducted at Vendor-based facilities and KCP&L testing team members travelled to the vendor site to perform the testing on the system. FAT was executed to demonstrate that the integration capabilities were operational and that the system was ready to be migrated for more robust, KCP&L hands-on testing. As FAT was a prerequisite to installation and connection with other systems on site, Integration FAT was done to ensure the system and interfaces met the pre-set specifications and all functional requirements were met as specified in the design requirements. It was typical that testing activities would result in identification of integration functions that did not work as expected. In these cases, identified defects would be documented and prioritized for resolution (fixed immediately where possible).

FAT included both structured and unstructured testing to thoroughly test the base functionality of the interfaces. When executed, efforts were mainly performed by the vendor team, but the KCP&L testing team was involved at the vendor site to monitor the FAT activities, identify defects, and track them to resolution. Where possible, the vendor team endeavored to have major defects resolved at the vendor site and during the FAT activities. Changes and fixes could be installed easily at the vendor site rather than at KCP&L where the constraints would increase (involving KCP&L change control and diminished familiarity with installation protocols). In many cases, Integration FAT could be conducted during the same vendor site visit as System FAT, but performed after verifying the core system capabilities were working as expected. The two main stages to FAT were as follows:

2.3.2.2.1 Integration Factory Acceptance Test Planning

Prior to the KCP&L Integration FAT teams traveling to vendor facilities, significant efforts were conducted in advance to ensure maximum effectiveness while onsite. These activities included:

- Test Books – Test books were created and available from vendors for their productized and customized interfaces. Given the more custom nature of integration between systems, vendors may have created these based on requirements specification. These were provided to KCP&L in the early stages of the project for planning purposes.
- Customization – Vendor provided test books were reviewed by the test team to ensure the tests were comprehensive and that the detailed steps were logical. In some cases, the test team determined that some functionality was not required and removed those functional tests. Alternatively, the test team may have determined that the test book was insufficient and that additional testing was required. In these cases, additional test cases and steps were drafted and included into the test book. The customized test books were then shared with the vendor to ensure agreement on the scope of the test execution effort.

2.3.2.2.2 Integration Factory Acceptance Test Execution

Based on the preparations directly above, the KCP&L Integration FAT teams began efforts to review the functionality as configured:

- Pre-FAT – As vendors concluded their initial configuration efforts in the development environments, they began comparing the implemented functionality against the tests documented in the test books. Many of these efforts were performed independently by the vendor, but in preparation for FAT execution some of these tests were monitored by the KCP&L testing teams. Upon successful demonstration of preliminary integration functionality, the code and configurations were migrated out of the development environment and into lab where it was ready for preliminary FAT execution.
- Structured Testing – Once the vendor was sufficiently confident of the system and integration configurations, the KCP&L team traveled to the vendor facility to jointly work through the documented test book and verify that the integration capabilities were working as expected. This portion of testing is primarily performed by the vendors with KCP&L staff monitoring the system performance. Much of this activity strictly adhered to the steps outlined in the documentation.
- Unstructured Testing – Conducted in parallel with structured testing, this effort was somewhat more vague in that it allowed the testing team to be creative and test functionality in ways not exactly documented to see how the interfaces performed. Similar to the structured testing, the vendor performed the actions necessary in response to questions asked by KCP&L to see certain functionality. This is done because some of these tests were not possible to be considered in advance due to a lack of understanding of interface capabilities.
- Variance Documentation – Throughout the FAT execution, there were numerous functional items that did not perform within tolerances. These variances were documented and tracked to help increase the stability and functional capabilities of the integration capabilities. Once a sufficient number of variances had been resolved, the system was migrated out of the Development environment into the demo environment for Integration Site Acceptance Testing.

2.3.2.3 Site Acceptance Testing

This was the first step to deploying the interfaces and preparing them for real-world communications between systems. It was used to demonstrate that the core integration capabilities verified in the controlled vendor environments continued to work in end-state environments. The system had already gone through FAT, but the relocation of the system and installation in a new environment and the additional nuances of real world connectivity (as compared to a more simulated environment at the vendor site) introduced new complexities and challenges into the system. The interfaces and system responses must be further tested on site to ensure that the design specifications were met and that the individual interfaces were ready to be fully integrated and ready for further exhaustive end-to-end interoperability testing.

SAT followed a similar structure to FAT but additionally confirming that the interfaces were stable at the KCP&L site with the real world data and complexities. Similarly, it was comprised of structured and unstructured testing. The KCP&L testing team performed SAT activities completely autonomously, with occasional support from the vendors. In many cases, Integration SAT could be conducted in parallel with System SAT, but performed after verifying the core system capabilities were working as expected. The two main stages to SAT were as follows:

2.3.2.3.1 Integration Site Acceptance Test Planning

Prior to the KCP&L Integration SAT teams beginning onsite testing, significant efforts were conducted in advance to ensure maximum effectiveness. These activities included:

- Test Books – Test books were created and available from vendors for their productized and customized interfaces. Given the more custom nature of integration between systems, vendors may have created these based on requirements specification. These were provided to KCP&L in the early stages of the project for planning purposes.
- Customization – Vendor provided test books were reviewed by the test team to ensure the tests were comprehensive and that the detailed steps were logical. In some cases, the test team determined that some functionality was not required and removed those functional tests. Alternatively, the test team may have determined that the test book was insufficient and that additional testing was required. In these cases, additional test cases and steps were drafted and included into the test book. The customized test books were then shared with the vendor to ensure agreement on the scope of the test execution effort. In addition, the test team will begin to identify test data and scenarios that can be applied to the finalized test cases.

2.3.2.3.2 Integration Site Acceptance Test Execution

Based on the preparations directly above, the KCP&L Integration SAT teams began efforts to review the functionality as configured:

- Pre-SAT – As the systems were prepared for SAT testing, changes were implemented in the demo environments. Vendors began shifting their vendor-hosted configurations to demo environments. KCP&L IT received final internally-hosted hardware and installed as necessary. In all cases, interfaces were established and stabilized; special care was paid to ensure that KCP&L hosted ESB capabilities were working as expected to support integration. Systems and interfaces were reviewed by the test team on a daily basis to ensure stability and readiness for more robust testing.
- Structured Testing – As the interfaces stabilized, the KCP&L team began conducting tests from the documented test book and verified that it was working as expected. This portion of testing strictly adheres to the steps outlined in the documentation.
- Unstructured Testing – Conducted in parallel with Structured testing, this effort was somewhat more vague in that it allows the testing team to be inspired and test functionality in ways not exactly documented to see how the system performs. This was done because some of these tests were not possible to consider in advance due to a lack of understanding of interface capabilities.
- Variance Documentation – Throughout the SAT execution, there were numerous functional items that did not perform within tolerances. These variances were documented and tracked to help increase the stability and functional capabilities of the system and interfaces. Once a sufficient number of variances had been resolved, the systems and integration capabilities were ready for additional levels of testing (e.g. Interoperability, Demonstration).

2.3.2.4 Details

As mentioned in the beginning of this section, Integration Testing was performed for all system to system communications. As such, a test book was created and executed for each system interface. However, given the SGDP's focus on 61968, OpenADR, and ZigBee capabilities, only a subset of test books are being included for reference as part of this report. The table below lists the functional area and specific system test books which have been included in Appendix I. However, they are not the exact test books from the project and instead are a standardized iteration for purposes of this report to highlight the capabilities and testing objectives. In many cases, the actual test books included individual test steps on the specific systems and in some cases, included proprietary or confidential vendor information about their system's internal functionality.

Table 2-17: Integration Test Books

Functional Area	System Integration	Appendix I: Sub-Appendix Location
Smart Distribution	DMS-DERM	I.2.1 DMS-DERM (Joint Vendor Testing) I.2.2 DMS-DERM (DERM Focus)
Smart Distribution	OMS-MDM: Outage Restoration	I.2.3 OMS-MDM (Outage Restoration Event) I.2.4 OMS-MDM (Outage Restoration – Flex Sync)
Smart Generation	OMS-MDM: Power Status Verification	I.2.5 OMS-MDM (Power Status Verification)
Smart Generation	DERM-HEMP	I.2.6 DERM-HEMP (DERM Focus)
Smart Metering	AHE-MDM	I.2.7 AHE-MDM (L+G Adapter) I.2.8 AHE-MDM (MDM VPN) I.2.9 AHE-MDM (MTR Connect-System Side Processing) I.2.10 AHE-MDM (ESB Processing) I.2.11 AHE-MDM (Outage Restoration Event) I.2.12 AHE-MDM (Outage Restoration – Flex Sync) I.2.13 AHE-MDM (Power Status Verification)
Smart End-Use	MDM-CIS	I.2.14 MDM-CIS (Aggregation) I.2.15 MDM-CIS (RSO Detail) I.2.16 MDM-CIS (RSO E2E) I.2.17 MDM-CIS (RSO Online GUI) I.2.18 MDM-CIS (RSO Web Services) I.2.19 MDM-CIS (L+G Adapter) I.2.20 MDM-CIS (MDM VPN) I.2.21 MDM-CIS (Outage Restoration Event) I.2.22 MDM-CIS (Power Status Verification)
Smart End-Use	HEMP-AHE	I.2.23 HEMP-AHE (Network & Device Comms.)

2.3.3 End-to-End Interoperability Testing

End-to-End Interoperability Testing represents the final detailed testing effort in which each step of a given cross-system data flow is tested. In earlier stages of testing, verification efforts thoroughly confirmed the detailed functionality and communications between individual systems. This effort allowed for detailed, end-to-end functionality confirmation which could span multiple combinations of systems and connecting interfaces. To this end, this effort represented a convergence between all system-specific and integration capabilities previously tested. The test team's familiarity with the systems and interfaces up to this stage represented vital institutional knowledge that were key inputs to conducting these Interoperability tests and verifying End-to-End functionality.

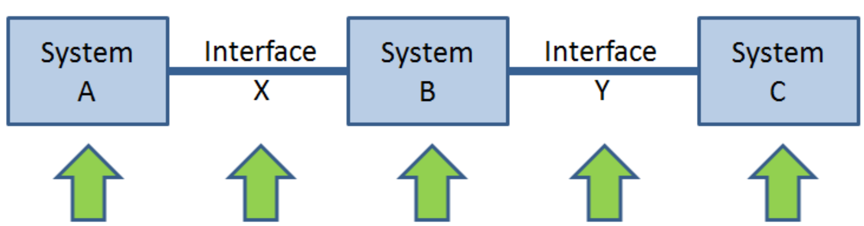
In this context, this section is broken down into the following subsections which give additional context to the scope of this effort:

- Description – A narrative overview of various special considerations and approaches applicable to this Interoperability Testing effort.
- Interoperability Flows – A description of the inventory of system and data flow for which Interoperability Test scripts were created.
- Interoperability Test Scripts – A detailed review of the test script documentation structure, inventory, and detailed cross reference of where certain scripts are captured in the appendix.

2.3.3.1 Description

End-to-End Interoperability Testing had a different focus than earlier stages of testing. Instead of detailed reviews of every possible permutation and function available, this testing effort was based on a definition of end-to-end data flows that achieved certain high-level objectives. These data flows, or scenarios, tended to be larger in scope, but fewer in number than the specific test books of earlier stages. As such, testing verified that the data flowed sequentially between systems to ensure that the data remains accurate through each step of the overall data transmission. Whereas inputs for earlier integration tests between systems may have been simulated data (due to lack of readiness in upstream systems and interfaces), the inputs for each step of Interoperability Tests were the outputs from earlier steps within the sequence for a given Interoperability flow. The tested capabilities include data translation, data receipt, firewall configuration, MQ configuration and all native system algorithms. Given this detailed attention paid during testing, additional interoperability focused defects were discovered and remediated.

Figure 2-86: End-to-End Interoperability Testing



2.3.3.1.1 Resourcing

Testing efforts began with high-level planning to ensure that environments and staff were available and ready. While environment considerations are elaborated on below, staffing impacts were crucial from the beginning of planning efforts. By ensuring staff availability early on, they were able to participate in design workshops, configuration reviews, and training sessions for the individual systems and interfaces to maximize their familiarity with the interface functions. Furthermore, they were also able to participate in the detailed System and Integration test efforts to ensure familiarity with functionality at all points of a given scenario. To this end, each interoperability scenario was handled as an independent test effort with different SMEs assigned to different systems and integration capabilities as befitting their individual expertise.

2.3.3.1.2 Planning and Preparation

While the Interoperability Test Team participated in the earlier stage of testing, it was not their primary activity. Instead, they were focused on leveraging their ever-expanding knowledge of the various systems as a key influencer to defining the scope of the Interoperability Testing effort. These steps started with a review of KCP&L's use cases and integration diagram to define interoperability scenarios. The team kept these in consideration to define scenarios which would be vital to future demonstration and operational testing efforts. The resulting flows are listed in Section 2.3.4.2 below.

With these flows defined, the team advanced to define very specific Interoperability Test Scripts. Unlike the System and Integration test books which were compiled by the vendor and later reviewed and tweaked by KCP&L, these scripts were fully compiled by the KCP&L Interoperability test team. Given that these flows spanned multiple systems (from multiple vendors) and frequently included some custom KCP&L interface logic, no vendor was in a position to carefully stitch these scripts together. However, the results of these efforts were vital to the team's ability to execute these tightly integrated testing flows.

Additionally, since execution of these scripts would cross the purview of multiple vendors' ability to remediate, it was determined that any defects identified would be captured into a separate KCP&L controlled tool for managing defects. As tools were investigated, the selected tool also had the ability to manage testing progress as well as defects. As such, the tool was configured as the ultimate repository for all Interoperability Test script steps. Further configuration was pursued for the defect tracking which included characteristics of Impacted System, Responsible Party, Severity, and Resolution Status.

2.3.3.1.3 Test Execution

Sequentially, Interoperability Testing commenced for an individual scenario once each component system and interface comprising the entire data flow was working sufficiently well. This allowed for maximum stability of the individual systems and interface configurations to ensure that data traffic issues were more indicative of interoperability problems as opposed to more rudimentary issues. Furthermore, it ensured maximum accuracy of the data quality to ensure that expected data formats were properly compiled and transferred.

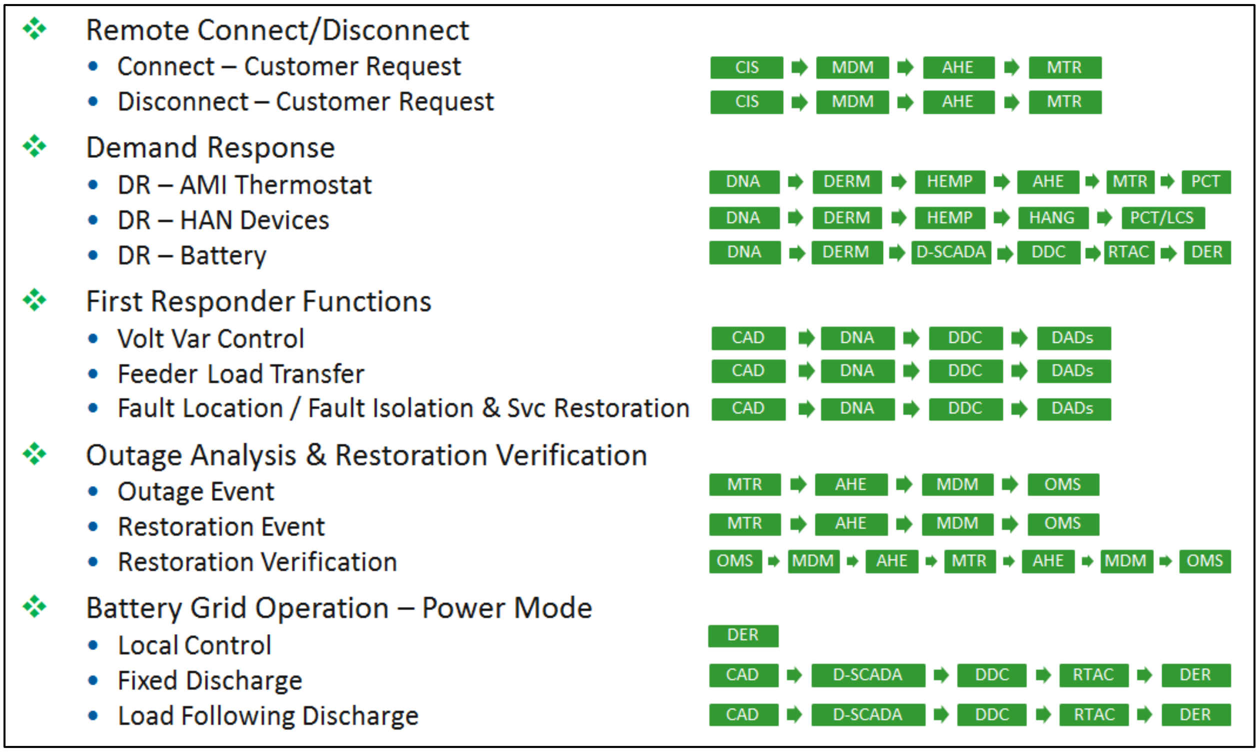
When testing efforts were pursued, some flows were reviewed in lab environments and some were in demo (production-like). The environment used was primarily dependent on the data flow being tested and the goal of minimizing impacted customers. For data flows having a higher likelihood of impacting customers (e.g. outage & restoration and First Responder functions), the lab environment was used as a means of safely seeing functionality. For other advanced capabilities, the demo environment was perfectly feasible, as customers would not be negatively impacted, even though some extra coordination between KCP&L organizations was required to ensure safe operation of field devices (e.g. Battery DR and Volt/VAR Control)

Upon completion, Interoperability Testing resulted in very few incremental defects which is a testament to the quality design and test execution performed explicitly for the System and Integration tests. Where necessary, identified defects were logged in the defect management tool and progress was tracked allowing for resolution.

2.3.3.2 Interoperability Flows

As mentioned above, numerous data flows were compiled and reviewed for end-state functionality and the basis for procedural documentation. The scenarios listed below include the same functional capabilities as outlined in the End-to-End Field Demonstration section (as Interoperability is the implicit preparation for that stage). Figure 2-87 was created to show the cross-system relationships between systems in given scenarios. As various scenarios were ready and proven out, this diagram was also used to track development/testing status for high-level status reporting by color coding the boxes and integration points.

Figure 2-87: Interoperability Flows

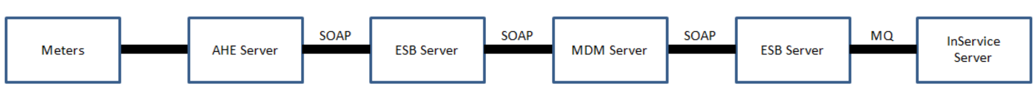


2.3.3.3 Interoperability Test Scripts

For each of the flows documented, a detailed Interoperability Test Script was produced and ensured comprehensive testing of all required components of a given data flow. While the overall sequence of steps could become complex, the scripts themselves were designed to be simple, straightforward, and approachable. A breakdown of the script structure is shown below along with a list of available scripts included in the appendix for review.

- Systems Integration Diagram – The beginning of each scenario shows which servers/systems/devices are connected and communicating to allow the data to flow in an end to end manner. An example of this detail data flow is shown below.

Outage and Restoration Events



The diagram can be interpreted as follows:

- **Boxes** – Specific servers or devices connected together to enable the data flow. In some cases these will represent specific systems that went through System Testing efforts. In other cases (like “ESB Server”), the box will represent a server that enable data traffic to be routed properly and was a potential point of failure; as such it is explicitly listed for inclusion in end-to-end testing.
- **Lines** – Specific interfaces between servers or devices that enable data traffic. These largely correspond to the Integration Tests performed in earlier phases, but as applicable here, fewer nuances could be explored in great detail.

- Preconditions – Each testing scenario had some server setup required or specific devices which would be used during testing. This information was thought out in advance in a highly detailed fashion and included in this section. Later, during testing, this section would be referenced to ensure that the tested scenarios were precisely recreated and executed. An example of this detail data flow is shown below.

Remote Connect and On-Demand Read (Demo)

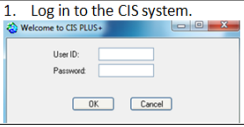
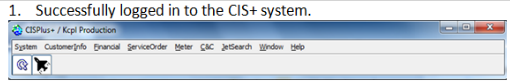
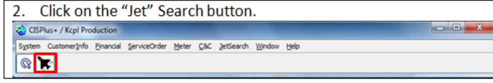
Precondition:

- Prior to entering a turn on order in GUI, make sure to change the Positive ID flag to ‘P’ in the green screens for each customer. In CIS+, pull up the customer ID on the PER screen (green screen) and panel left once for Positive ID field. Enter a ‘C’ in the Action field, ‘P’ in the Positive ID field and press Enter. (This is to verify that customer can open the account and turn on the meter. This has to be done before the meter service request)
- Meter has disconnect switch and Source is connected

Remote Connect Meter Info – Production:

- Meter ID: 1284810439383 Service Point ID: 9324790610 Account Number: 5350203882

- Test Steps – The final section of each test script are the detailed test steps. Where necessary screenshots are embedded in the step to ensure accuracy and text is used to describe the necessary actions required. An example of a test step is included below:

Steps	*Expected Results*
1. Log in to the CIS system. 	1. Successfully logged in to the CIS+ system. 
2. Click on the “Jet” Search button. 	2. The JetSearch window pops up.

The diagram can be interpreted as follows:

- Detailed steps about what needs to happen with corresponding screenshot
- Detailed explanation about what the system should do as a result along with corresponding screenshot

- Test Script Inventory – Unlike the filtered test book inventories compiled for System and Integration Testing, every Interoperability Test script that was produced is included in Appendix J. Whereas the test books from the earlier stages were not the actual test books (due to standardization and proprietary content), these scripts were standardized from the outset, so the actual test scripts are included. That being said, these documents do include a number of test steps which some vendors have deemed to include proprietary or confidential information about their system’s internal functionality. The inventory of Interoperability Test Scripts is shown below.

Table 2-18: Interoperability Testing Documentation

Functional Area	System Integration	Appendix J: Sub-Appendix Location
Remote Connect/Disconnect	Connect – Customer Request	J.1: Remote Connect and Disconnect
Remote Connect/Disconnect	Disconnect – Customer Request	J.1: Remote Connect and Disconnect
Demand Response	DR – AMI Thermostat	J.2: Demand Response – AMI Thermostat
Demand Response	DR – HAN Devices	J.3: Demand Response – HAN Devices
Demand Response	DR – Battery	J.4: Demand Response – Battery
Demand Response	DR – EVCS	J.5: Demand Response – EVCS
First Responder Functions	Volt/VAR Control	J.6: First Responder Function – Volt/VAR Control
First Responder Functions	Feeder Load Transfer	J.7: First Responder Function – Feeder Load Transfer
First Responder Functions	Fault Location/Fault Isolation & Svc Restoration	J.8: First Responder Function – Fault Location, Isolation, and Service Restoration
Outage Analysis & Restoration Verification	Outage Event	J.9: Outage and Restoration Events
Outage Analysis & Restoration Verification	Restoration Event	J.9: Outage and Restoration Events
Outage Analysis & Restoration Verification	Restoration Verification	J.10: Power Status Verification
Battery Grid Operation – Power Mode	Local Control	J.11: Battery Grid Operation – Local Control (Discharge)
Battery Grid Operation – Power Mode	Fixed Discharge	J.12: Battery Grid Operation – Fixed kW (Discharge)
Battery Grid Operation – Power Mode	Load Following Discharge	J.13: Battery Grid Operation – Load Following (Discharge)

2.3.4 End-to-End Field Demonstrations

End-to-End Field Demonstrations represent the culmination of the incremental testing progression. In earlier stages of testing, verification efforts thoroughly confirmed the detailed functionality and communications between impacted systems. This effort allowed final functionality confirmation and preparation for demonstration to interested parties. To this end, this effort represented a convergence between formalized testing and the Education and Outreach objectives of this initiative. The test team's familiarity with the systems and interfaces up to and throughout this stage represented vital institutional knowledge that were key inputs to creating and preparing for demonstrations.

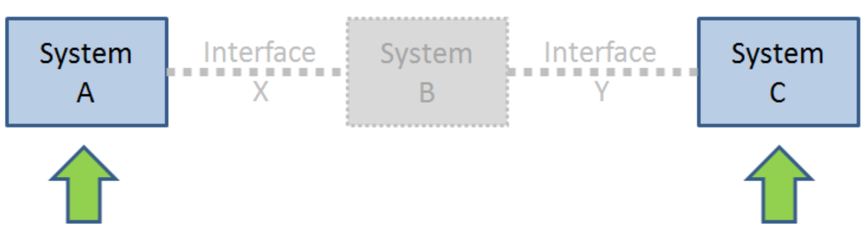
In this context, this section is broken down into the following subsections which give additional context to the scope of this effort and the educational materials resulting from its pursuit:

- Description – A narrative overview of various special considerations and approaches applicable to this demonstration effort.
- Demonstration Flows – A description of the inventory of system and data flow for which demonstration scripts were created.
- Demonstration Scripts – A detailed review of the demonstration script documentation structure and inventory and detailed cross reference of where certain scripts are captured in the appendix.

2.3.4.1 Description

End-to-End Field Demonstrations commenced in a similar manner to Interoperability testing in that it tested the same inventory of functional data flows with the same triggering inputs and concluding outputs. However, where Interoperability also involved a detailed review of the individual connections between stand-alone systems, at this stage for Field Demonstration scripting, minimal intervention between end-point systems was pursued. By having users actively verify functionality at the trigger and concluding points of a given data flow, all intermediary capabilities were shown to be implicitly functional. These capabilities include data translation, data receipt, firewall configuration, MQ configuration and all native system algorithms. In so doing, the integrated solution was proven ready to be demonstrated to various audiences.

Figure 2-88: End-to-End Field Demonstration



Sequentially, the final communication verification indicative of this stage was pursued after Interoperability Testing was complete. This allowed for maximum stability of the systems and interface configurations to ensure that data traffic was not interrupted mid-transit. Furthermore, it ensured maximum accuracy of the data quality to ensure that expected data formats were properly compiled and transferred.

When verification efforts were pursued, some flows were reviewed in lab environments and some were in demo (production-like). The environment used was primarily dependent on the data flow being tested and the goal of minimizing impacted customers. For data flows having a higher likelihood of impacting customers (e.g. outage restoration and First Responder functions), the lab environment was used as a means of safely seeing functionality. For other advanced capabilities, the demo environment was perfectly feasible, as customers would not be negatively impacted, even though some extra coordination between KCP&L organizations was required to ensure safe operation of field devices (e.g. Battery DR and Volt/VAR Control).

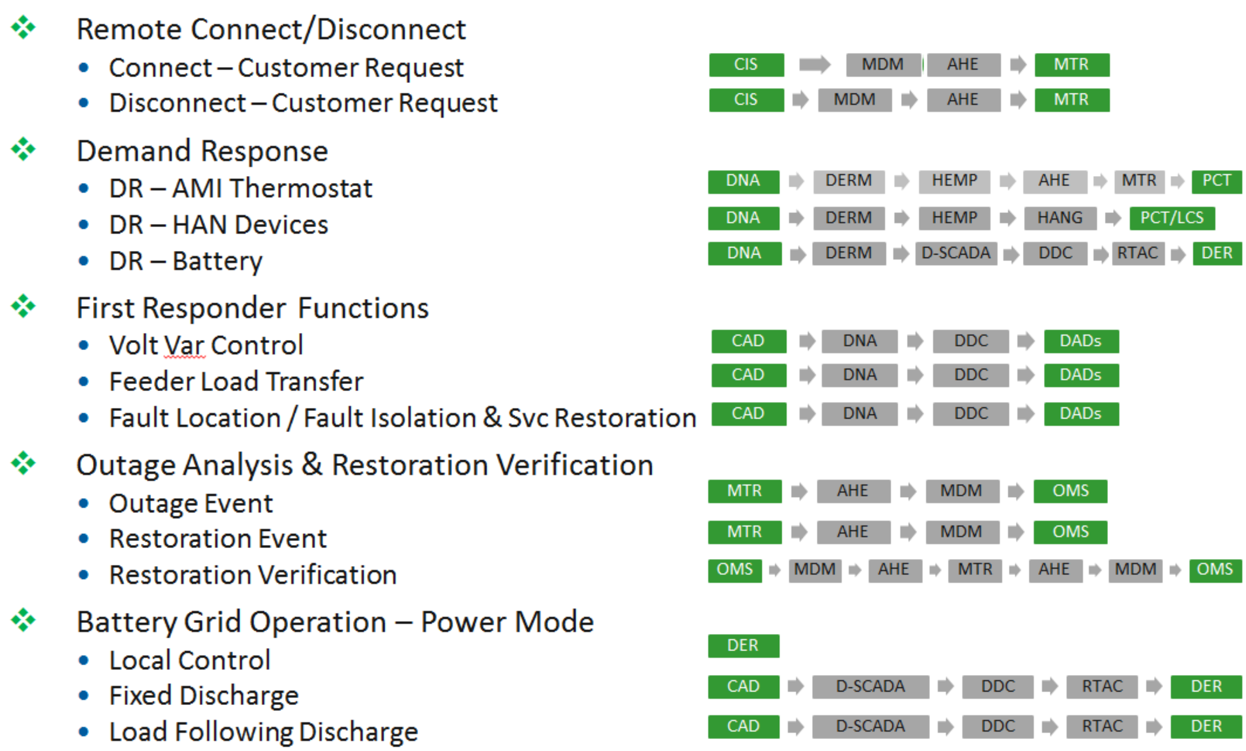
Ultimately, all validation efforts during this stage were more a formality as the detailed verification of capabilities were conducted in the earlier Interoperability stage. An implication of this was that variances were not created during this stage, as all significant defects were identified and resolved prior to commencement.

All efforts to perform these verifications were performed by the Subject Matter Experts (SMEs) and team members that performed the Interoperability and earlier testing. By leveraging the same expertise, quality was maximized and transition efforts to different team members were minimized. As the process became more streamlined through repetition, a natural, steady-state sequence of tasks became established. The team then advanced efforts to document these steps in considerable detail for future use. Specifically, it was anticipated that non-SMEs could potentially be in a position to demonstrate the system at some future date when a SME was not available to conduct the demonstration. As such, the goal of this demonstration material was to capture as much pertinent SME process knowledge as possible for future use.

2.3.4.2 Demonstration Flows

As mentioned above, numerous data flows were compiled and reviewed for end-state functionality and the basis for procedural documentation. The demonstration flows listed in Figure 2-89 include the same functional capabilities as outlined in the Interoperability Testing section. However, given that the intended audience members for these demonstrations are anticipated to be non-technical, there will be no focus on the capabilities of the intermediary systems which have been greyed out.

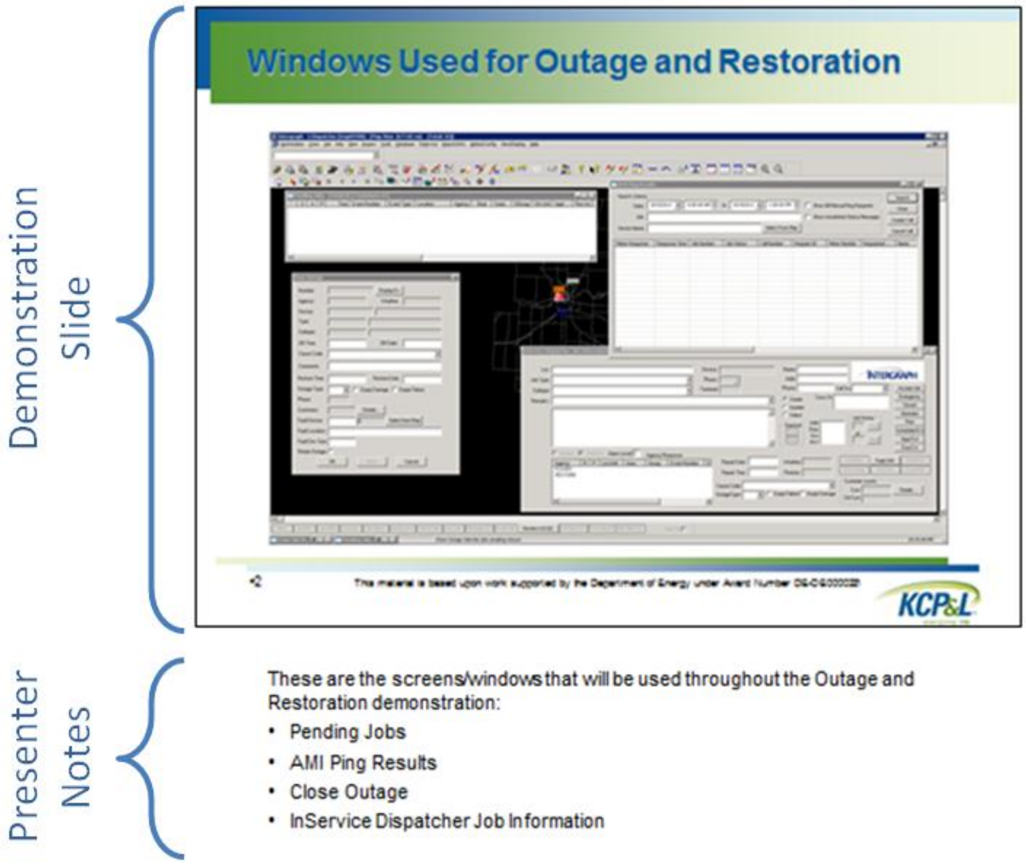
Figure 2-89: Demonstration Flows



2.3.4.3 Demonstration Scripts

For each of the flows documented, a detailed Demonstration Script was produced and available as support for anyone conducting a demonstration to interested audiences. While the overall sequence of steps could become complex, the scripts themselves were designed to be simple, straightforward, and approachable. A breakdown of the script structure is shown in Figure 2-90 along with a list of available scripts included in Appendix K for review.

Figure 2-90: Demonstration Script



- Demonstration Slide – Each demonstration script has a series of screen captures that show system capabilities in a step by step manner. These were intended to be detailed enough that if someone were trying to use the system itself, they should be able to follow the steps as outlined.
- Presenter Notes – In addition to the screenshots above, each demonstration script file will also include a number of notes, considerations, and talking points applicable to each slide. While not a requirement for a presentation being given, these serve to support the presenter as well as convey details to a reviewer who may be perusing the content.

Table 2-19: End-to-End Demonstration Scripts

Functional Area	System Integration	Appendix K: Sub-Appendix Location
Remote Connect/Disconnect	Connect – Customer Request	K.1: Remote Connect and Disconnect
Remote Connect/Disconnect	Disconnect – Customer Request	K.1: Remote Connect and Disconnect
Demand Response	DR – AMI Thermostat	K.2: Demand Response – AMI Thermostat
Demand Response	DR – HAN Devices	K.3: Demand Response – HAN Devices
Demand Response	DR – Battery	K.4: Demand Response – Battery
Demand Response	DR – EVCS	K.5: Demand Response – EVCS
First Responder Functions	Volt/VAR Control	K.6: First Responder Function – Volt/VAR Control
First Responder Functions	Feeder Load Transfer	K.7: First Responder Function – Feeder Load Transfer
First Responder Functions	Fault Location/Fault Isolation & Svc Restoration	K.8: First Responder Function – Fault Location and Service Restoration
Outage Analysis & Restoration Verification	Outage Event	K.9: Outage and Restoration Events
Outage Analysis & Restoration Verification	Restoration Event	K.9: Outage and Restoration Events
Outage Analysis & Restoration Verification	Restoration Verification	K.10: Power Status Verification
Battery Grid Operation – Power Mode	Local Control	K.11: Battery Grid Operation – Local Control (Discharge)
Battery Grid Operation – Power Mode	Fixed Discharge	K.12: Battery Grid Operation – Fixed kW (Discharge)
Battery Grid Operation – Power Mode	Load Following Discharge	K.13: Battery Grid Operation – Load Following (Discharge)

2.4 Operational Demonstration and Testing Plans

The KCP&L project has been divided into five subprojects to demonstrate the deployed SmartGrid technologies and applications that enable specific DOE-defined Smart Grid Functions. Table 2-20 lists all 23 Demonstration Applications, the SmartGrid Function they support, and the subprojects deploying each application.

This section contains an overview of each SmartGrid Function supported by the Demonstration Applications and a description of potential benefits from each enabled Smart Grid Function. For each Demonstration Application, an Operational Demonstration Test Plan was developed that includes descriptions of the technology that will be applied, a description of expected results, relevant impact metrics, data to be collected and analyzed, and the benefit analysis method that will be used.

Table 2-20: KCP&L Operational Demonstration/Tests

Smart Grid Project Application Demonstrations/Tests T = Technology Demonstration Only B = Operational Benefit Test s = Supporting Subproject		Demonstration Subproject				
Smart Grid Function	**Application**	**Smart Metering**	**Smart End-Use**	**Smart Substation**	**Smart Distribution**	**Smart Generation**
Automated Voltage & VAR Control	Integrated Volt/VAR Management (VVC)	s		s	**B**	
Real-Time Load Transfer	Feeder Load Transfer (FLT)	s		s	B	
Automated Feeder & Line Switching	Fault Isolation & Service Restoration (FISR)			s	B	
Automated Islanding & Reconnection	Feeder Islanding with Grid Battery			s	s	**T**
Diagnosis and Notification of Equipment Condition	Substation Protection Automation			**T**		
	Asset Condition Monitoring			**B**	**B**	
	Hierarchical Control (DCADA)			**T**	**T**	
Real-Time Load Measurement and Management	Automated Meter Reading (AMR)	**B**				
	Remote Meter Disconnect/Re-Connect	**B**				
	Meter Outage Restoration w/PSV (PSV)	**T**			**T**	
	Demand Response Events (DR)	**T**	s			**T**
Customer Electricity Use Optimization	Historical Interval Usage Information (HEMP)	s	**B**			
	In-Home Display (IHD)	s	**B**			
	Home Area Network (HAN)	s	**B**			
	Time-of-Use Rate (TOU)	**B**	**B**			
Distributed Production of Electricity	Distributed Rooftop Solar Generation					**B**
Storing Electricity for Later Use	Electric Energy Time Shift					**B**
	Electric Supply Capacity				s	**B**
	T&D Upgrade Deferral				s	**B**
	Time of use Energy Cost Mgmt.		**B**			
	Electric Service Reliability		**B**			
	Renewable Energy Time Shift		**B**			
	PEV Charging					**B**

2.4.1 Automated Voltage and VAR Control

Automated voltage and VAR control requires coordinated operation of reactive power resources such as capacitor banks, voltage regulators, transformer load-tap changers, and DG with sensors, controls, and communications systems. These devices could operate autonomously in response to local events or in response to signals from a central control system.

2.4.1.1 DOE SGCT Function to Benefit Rationale

Automated VVC is performed through devices that can increase or lower voltage and can be switched or adjusted to keep the voltage in a required range. Control systems could determine when to operate these devices, and do so automatically. This function is the result of coordinated operation of reactive power resources such as capacitor banks, voltage regulators, transformer load-tap changers, and distributed generation (DG) with sensors, controls, and communications systems. These devices could operate autonomously in response to local events or in response to signals from a central control system. By better managing voltage and VAR resources, the transmission and distribution network can be optimized for electrical efficiency (lower losses), and can allow utilities to reduce load through "energy conservation voltage reduction" while maintaining adequate service voltage. These load reductions will reduce the amount of generation required. This function provides five benefits:

- Reduced Ancillary Service Cost – Ancillary services are necessary to ensure the reliable and efficient operation of the grid. As discussed above, ancillary services are provided by generators, and voltage and VAR support. The level of ancillary services required at any point in time is determined by the grid operator and/or energy market rules. To the extent that reactive power resources can be better coordinated to reduce load and reactive power requirements from generation, ancillary service costs for voltage and VAR support could be reduced, decreasing the cost for market participants and utilities.
- Reduced Transmission and Distribution Operations Cost – Automated voltage and VAR control eliminates the need to send a line worker or crew to the location of reactive devices in order to operate them. This reduces the cost associated with the field service worker(s) and service vehicle. The impact of this benefit is determined by estimating the percentage of a field crew's time is dedicated to capacitor switching, and then estimating the time saved by the field service personnel.
- Reduced Electricity Losses – Coordinating the settings of voltage control devices on the transmission and distribution system ensures that customer voltages remain within service tolerances, while minimizing the amount of reactive power provided. Optimizing voltage and VAR in this way can reduce the amount of transmission and distribution losses associated with delivering a given amount of energy.
- Reduced CO_2 Emissions – Energy reductions achieved through improved efficiency and energy conservation voltage reduction will reduce the amount of generation required to serve load. Assuming that the generation is fossil-based, emissions will be reduced.
- Reduced SOx, NOx, and PM-2.5 Emissions – Energy reductions achieved through improved efficiency and energy conservation voltage reduction will reduce the amount of generation required to serve load. Assuming that the generation is fossil-based, emissions will be reduced.

The KCP&L project team has identified two additional benefits provided by this function.

- Deferred Generation Capacity Investments – Energy reductions achieved through improved efficiency and energy conservation voltage reduction can be used to reduce the amount of central station generation required during peak times. This may improve the overall load profile and allow a more efficient mix of generation resources to be dispatched. This could save utilities money on their generation costs.

- Reduced Electricity Consumption/Cost – Energy reductions from customer loads can be achieved through conservation voltage reduction. Changes in customer usage can result in reductions in the customers total cost of electricity and reduce the electricity that must be generated and pass through the T&D lines.

2.4.1.2 Integrated Volt/VAR Management

KCP&L Operational Test Plan
A. Description KCP&L currently has a very active capacitor deployment and automation program where each capacitor operates autonomously in response to local conditions to satisfy the circuit operating (voltage and power factor) criteria. This VVC operational test will compare the operational performance of the SmartGrid Automated VVC program relative to the existing KCP&L capacitor program controls. The SmartGrid Automated VVC function extends the legacy KCP&L VVC design parameters to include losses and objective functions. The four objective functions are to: • Minimize the sum of power losses • Minimize the power demand • Maximize the substation transformer reactive power • Maximize the difference between energy sales and energy cost The SmartGrid Automated VVC program continuously monitors circuit conditions, uses a distribution power flow to calculate circuit voltage profile and losses; and centrally controls power transformer load tap changer (LTC) position, voltage regulators, and switchable capacitors to meet the prescribed objective functions. The project team will evaluate each of the four objective functions in comparison to current KCP&L capacitor control schemes.

B. Expected Results
This operational demonstration is expected to yield the following:
• For each objective function The project team expects to see an incremental improvement in circuit operational performance indicators including:
    − Voltage profile
    − Power factor at circuit head
    − Electrical losses
    − Economics
• Based on the circuit performance improvements obtained under each VVC objective function, a recommended objective function would be selected for sustained operation of the SmartGrid Demonstration Circuits.
• Due to KCP&L's active capacitor deployment & automation program, a significant improvement may not be achievable.
• An overall 1-3% reduction in active power consumption would be expected on the VVC controlled feeders or transformer

C. Relevant Impact Metrics

The Operational Testing of this application will contribute to these Impact Metrics.

Distribution	Feeder Aggregated Average Real Load (MW)
Distribution	Feeder Aggregated Average Reactive Load (MVAR)
Distribution	Feeder Hourly Load Curves (MW)
Distribution	Feeder Hourly Reactive Load Curves (MVAR)
Distribution	Avoided Distribution Losses (MWh)

At each reporting milestone, operational test, or demonstration period, data will be compared to baseline data to determine a quantified impact. Quantified impacts measured will be reported in semi-annual impact metric reports.

D. Benefits Analysis Method/Factors

The DOE SGCT will be used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits will be quantified.

- Reduced Electricity Losses
- Deferred Generation Capacity Investments
- Reduced Electricity Consumption/Cost

Benefits will be calculated using SGCT formulas. The following factors will be measured, projected or calculated during the application operation and/or demonstration.

Reduced Electricity Losses

- Distribution Feeder Load (MW)
- Distribution Feeder Losses (MWh) (base & projected)
- Distribution Losses (%)(base & projected)

Deferred Generation Capacity Investment

- Distribution Feeder Load Reduction at Annual Peak Time (MW)

Reduced Energy Costs (Consumer)

- Reduced Total Annual Electric Consumption (kWh) by customer class.

E. Baseline Data & Control Groups

AMI metering that is deployed for all customers, circuits, and distributed energy resources within the SGDP area. The following usage data will be available for baselines::

- 15 minute interval load data of all customers
- Average hourly interval load data by customer class
- 15 minute interval total load data for circuit
- Aggregated interval load data for all customers by circuit

The following circuit voltage data will be available from the HIS for analysis:

- Historical circuit voltage profile readings at SCADA enabled devices.

The following system level energy production data will be available for analysis:

- Historical and current hourly system energy production load profile data.
- Historical weather adjusted system energy production load profile data.

F. Testing Method/Methodology

The following points provide an overview of how the operational testing for this application will be accomplished:

- Testing for each control objective function will be on a week on/week off basis, to compare current legacy protection schemes to one of the central control objectives.
- Individual seasonal testing and data collection periods will be established for operation under each control objective function.
- Each objective function test will be 2 weeks (1 week on/1 week off). Testing will be done seasonally for each objective function. (4 periods of 8 weeks)
- During each test period, the DMS and VVC operational parameters will be adjusted to maximize the potential benefits achievable for objective control function being tested.
- The AMI system will be used to collect customer and circuit load profile data for each SGDP circuit. AMI customer and circuit data not involved in the test will be used as control for the analysis.
- DMS will collect voltage profile data for all SCADA enabled equipment and the AMI will collect under/over voltage alarms from customer AMI meters.

G. Analytical Method/Methodology

The following points provide an overview of the analytical methods that will be used to evaluate the impact and benefits of this application:

- AMI interval load data for all customer and circuit load meters within the Project area will be extracted from the MDM System through KCP&L's DMAT. The DMAT has built in functionality that will enable the aggregation and calculation of hourly load profiles of customer loads grouped by Circuit.
- For each operational test period aggregated customer data by circuit will be compared to circuit load meter data to determine the distribution system losses. The calculated distribution grid losses include technical (I^2R) losses along with unmetered load, theft and diversion.
- The DMS application provides a calculation of distribution (I^2R) technical losses. The delta DMS technical losses will be analyzed against the delta calculated distribution losses from the metering data.
- For each operational test period the off-week and control circuit data will be used as baseline data to determine a quantified impact (loss reduction, peak load reduction, etc.).
- For each operational test period DMS voltage for on/off week and control circuits will be used to determine the quantified impact on circuit voltage profile.
- Additionally, hourly pricing, hourly system load, hourly substation load (from SCADA), and hourly AMI feeder load from October 2012 through October 2014 will be obtained to determine potential savings over the entire project duration.

2.4.2 Real-Time Load Transfer

Real-time load transfer is achieved through real-time feeder reconfiguration and optimization to relieve load on equipment, improve asset utilization, improve distribution system efficiency, and enhance system performance.

2.4.2.1 DOE SGCT Function to Benefit Rationale

In areas that may have more than one distribution feeder, circuits may be switched and electrical feeds rerouted to make the distribution more efficient or more reliable. This function allows for real-time feeder reconfiguration and optimization to relieve load on equipment, improve asset utilization, improve distribution system efficiency, and enhance system reliability. This function provides these benefits:

- Deferred Distribution Capacity Investments – Load growth and feeder reconfiguration can lead to increased loading on lines and transformers, to the point where distribution capacity investments become necessary. Being able to automatically switch a portion of a distribution feeder A onto distribution feeder B will relieve the load on feeder A. In cases where feeder A and feeder B are connected to different substations, the load relief can have beneficial effects up to the substation level. This load shifting could enable utilities to postpone feeder upgrades for one or more years. Each year that a capital investment can be deferred can yield a significant savings in the utility's revenue requirement (equal to the capital carrying charge of the upgrade). Therefore, Real-Time Load Transfer could yield direct savings based on postponed capital investment.
- Reduced Electricity Losses – Higher line loading tends to affect delivery losses more than average load, and managing this peak could lead to improvements in electricity delivery efficiency. By being able to balance load among substation transformers and distribution feeders, the utility could reduce delivery losses.
- Reduced Major Outages – Transferring portions of a distribution feeder load from one substation to another could enable a utility to restore service to some outage customers more quickly than if they had to wait until their normal feeder was fully restored. Performing this load shifting manually would be impractical. However, by being able to do this remotely, a utility might be able to justify the cost in the interest of restoring some customers more quickly.
- Reduced CO_2 Emissions – Increased electricity delivery efficiency by managing peak line loads will reduce the amount of generation required to serve load. Assuming that the generation is fossil-based, emissions will be reduced.
- Reduced SOx, NOx, and PM-2.5 Emissions – Increased electricity delivery efficiency by managing peak line loads will reduce the amount of generation required to serve load. Assuming that the generation is fossil-based, emissions will be reduced.

2.4.2.2 Feeder Load Transfer

KCP&L Operational Test Plan
A. Description KCP&L circuit configurations are currently established based on engineering planning studies and that focus on optimizing the distribution system under peak load conditions. The Feeder Load Transfer application will perform a real-time analysis to determine the optimal radial distribution network configuration to serve the current load. The FLT analysis minimizes electrical losses while maintaining current and voltage levels within technical limits. Automated switches with two-way communications were deployed on the twelve SmartGrid distribution circuits to allow remote circuit reconfiguration. FLT will develop switching plans to implement the recommend configuration which may be implemented automatically or manually by the distribution gird operator.

B. Expected Results

This operational demonstration is expected to yield the following:

- FLT analysis makes changes to the "Normal" circuit configurations that will be more efficient and reduce distribution system losses.
- FLT may identify real-time, daily, or seasonal reconfigurations that will be more efficient and reduce distribution system losses.

C. Relevant Impact Metrics

The Operational Testing of this application will contribute to these Impact Metrics.

Distribution	Feeder Aggregated Average Real Load (MW)
Distribution	Feeder Aggregated Average Reactive Load (MVAR)
Distribution	Feeder Hourly Load Curves (MW)
Distribution	Feeder Hourly Reactive Load Curves (MVAR)
Distribution	Avoided Distribution Losses (MWh)

At each reporting milestone, operational test, or demonstration period, data will be compared to baseline data to determine a quantified impact. Quantified impacts measured will be reported in semi-annual impact metric reports.

D. Benefits Analysis Method/Factors

The DOE SGCT will be used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits will be quantified.

- Reduced Electricity Losses.
- Deferred Distribution Capacity Investments.

Benefits will be calculated using SGCT formulas. The following factors will be measured, projected or calculated during the application operation and/or demonstration.

Reduced Electricity Losses

- Distribution Feeder Load (MW)
- Distribution Losses (%)(base & projected)

Deferred Distribution Capacity Investments

- Capital Carrying Charge of Distribution Upgrade ($/yr)
- Distribution Investment Time Deferred (yrs)

E. Baseline Data & Control Groups

AMI metering that is deployed for all customers, circuits, and distributed energy resources within the SGDP area. The following usage data will be available for baselines:

- 15 minute interval total load data for circuit
- Aggregated interval load data for all customers by circuit

The following system level energy production data will be available for analysis:

- Historical and current hourly average and marginal energy production cost data.
- Historical and current hourly system energy production load profile data.

F. Testing Method/Methodology:

The following points provide an overview of how the operational testing for this application will be accomplished:

- Testing for the FLT application will occur periodically throughout the operational period during different seasons, times of day, and system loading levels.
- FLT testing will be conducted independently of VVC and other application testing that impacts distribution grid characteristics.
- With grid reconfiguration, measurement of distribution grid losses is extremely difficult. Therefore, the project team will determine the improved grid efficiency based on the DNA analytic calculations. Grid loss impact will be measured in two ways; 1) the FLT application provides a calculation of loss savings that is expected based on the proposed reconfiguration, 2) the DNA State Estimation/Load Flow loss calculations will be recorded before and after the reconfiguration is implemented.
- During each test period, the DMS FLT operational parameters will be adjusted to maximize the potential benefits achievable.
- The AMI system will be used to collect circuit load profile data for each circuit. AMI circuit data not involved in the test will be used as control for the analysis.
- DMS will collect voltage profile data for all SCADA enabled equipment.

G. Analytical Method/Methodology

The following points provide an overview of the analytical methods that will be used to evaluate the impact and benefits of this application:

- AMI interval load data for all circuit load meters within the Project area will be aggregated to develop an hourly load profile of the combined circuit load.
- For each operational test, the before and after calculated grid losses will be compared to determine the reduction in technical (I^2R) losses.
- Total annual loss savings will be project by calculated by extrapolating the individual test results using the annual hourly load profile for the project area.
- Additionally, hourly pricing, hourly system load, hourly substation load (from SCADA), and hourly AMI feeder load from October 2012 through October 2014 will be obtained to determine potential savings over the entire project duration.

2.4.3 Automated Feeder and Line Switching

Automated feeder switching is realized through automatic isolation and reconfiguration of faulted segments of distribution feeders via sensors, controls, switches, and communications systems. These devices can operate autonomously in response to local events or in response to signals from a central control system.

2.4.3.1 DOE SGCT Function to Benefit Rationale

Utilities design distribution feeders with switches so that portions of the feeder can be disconnected to isolate faults, or de-energized for maintenance. In most cases, these switches are manually operated, and require a service worker to travel to the switch location, coordinate switching orders with a dispatcher, and then physically operate the switch. Automatic Feeder Switching makes it possible to operate distribution switches autonomously in response to local events, or remotely in response to operator commands or a central control system.

Automatic Feeder Switching does not prevent outages; it simply reduces the scope of outage impacts in the longer term. This function is accomplished through the automatic isolation and reconfiguration of faulted segments of distribution feeders via sensors, controls, switches, and communications systems. Automatic Feeder Switching can reduce or eliminate the need for a human operator or field crew for operating distribution switches. This saves time, reduces labor cost, and eliminates "truck rolls". This function can provide six benefits:

- Reduced Transmission and Distribution Operations Cost – Automated or remote controlled switching eliminates the need to send a line crew to the switch location in order to operate it. This reduces the cost associated with the field service worker(s) and service vehicle.
- Reduced Sustained Outages – Automated Feeder and Line Switching means that the faulted portions of feeders and lines can be isolated by opening switches. By reconnecting some customers quickly (within minutes), significant outage minutes can be saved. This only works when a significant number of customers receive service upstream of the fault, with an automated switch between them and the fault. This function presumes that the switching is done within the scope of a single feeder. Automatic switching does not prevent the outage for all customers; it simply reduces the scope of its impact in the longer term.
- Reduced Restoration Cost – Being able to operate distribution switches without rolling trucks means lower restoration costs.
- Reduced CO_2 Emissions – Fewer truck rolls for switching means less fuel consumed by a service vehicle or line truck and leads to reduced emissions.
- Reduced SOx, NOx, and PM-2.5 Emissions – Fewer truck rolls for switching means less fuel consumed by a service vehicle or line truck and leads to reduced emissions.
- Reduced Oil Usage – Fewer truck rolls for switching means less fuel consumed by a service vehicle or line truck and leads to reduced oil usage.

2.4.3.2 Fault Isolation and Service Restoration

KCP&L Operational Test Plan
A. Description Fault isolation, fault location, circuit monitoring devices, and automatic circuit reconfiguration equipment will be deployed on the eleven SmartGrid distribution circuits. This will include two-way communications to enable system operators to continuously monitor and operate this equipment remotely. The systems will also automatically identify circuit faults and isolate them to smaller sections of the circuit when possible. Remaining sections of the circuit will be restored automatically without human intervention. Additionally, system operators will receive alerts regarding the faulted section and deploy field crews directly to the failed equipment, avoiding timely fault searching.
B. Expected Results This operational demonstration is expected to yield the following: • Reliability will improve, resulting in significant reductions in SAIFI and SAIDI. It is estimated that SAIFI could be reduced by 20%, SAIDI by 30%. • Operational costs will be reduced as manual switching will be executed remotely and fault locations will reduce fault searching time. It is estimated that manual switching could be decreased by 3-6 truck rolls per circuit per year.

C. Relevant Impact Metrics

The Operational Testing of this application will contribute to these Impact Metrics.

Distribution	SAIFI
Distribution	SAIDI
Distribution	CAIDI
Distribution	Total Customers Served by SAIDI/SAIFI
Distribution	Major Event – No. of Customers Affected
Distribution	Major Event – No. of Customers Affected w/out FISR
Distribution	Major Event – Total Restoration Time (hours)
Distribution	Major Event – Total Restoration Time w/out FISR (hours)
Distribution	Truck Rolls Avoided
Distribution	Avoided Distribution Operation Vehicle Miles
Distribution	Avoided CO_2 Emissions (tons)

At each reporting milestone, operational test, or demonstration period, data will be compared to baseline data to determine a quantified impact. Quantified impacts measured will be reported in semi-annual impact metric reports.

D. Benefits Analysis Method/Factors

The DOE SGCT will be used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits will be quantified.

- Reduced Sustained Outages
- Reduced Restoration Costs
- Reduced T&D Operations Costs
- Reduced CO_2 Emissions

Benefits will be calculated using SGCT formulas. The following factors will be measured, projected or calculated during the application operation and/or demonstration.

Reduced Sustained Outages

- SAIDI (base & projected)

Reduced Restoration Costs

- Avoided Distribution Restoration Costs ($) (crew outage trouble shooting)

Reduced T&D Operations Costs

- Avoided Distribution Operations Costs ($) (crew non-outage switching)

Reduced CO_2 Emissions

- Avoided Truck Rolls

E. Baseline Data & Control Groups

The following historical system level reliability statistics will be available for analysis:

- System Average Interruption Frequency Index (SAIFI)
- System Average Interruption Duration Index (SAIDI)
- Customer Average Interruption Duration Index (CAIDI)

F. Testing Method/Methodology

The following points provide an overview of how the operational testing for this application will be accomplished:

- KCP&L's legacy OMS will continue to be used by the Distribution Dispatcher to work lights-out and other trouble calls.
- The legacy OMS will continue to record all outage events and restoration efforts.
- The SGDP OMS will be used in study mode to perform an after-the-fact analysis to determine how the FISR application would have impacted outage response and restoration efforts.

G. Analytical Method/Methodology

The following points provide an overview of the analytical methods that will be used to evaluate the impact and benefits of this application:

- In the after-the-fact analysis of each major event the following data will be calculated to determine how the FISR application functions:
  - Major Event - No. of Customers Affected
  - Major Event - No. of Customers Affected w/out FISR
  - Major Event – Total Customer Outage Hours (hours)
  - Major Event – Total Customer Outage Hours w/out FISR (hours)
  - Major Event – Total Restoration Time (hours)
  - Major Event – Total Restoration Time w/out FISR (hours)

2.4.4 Automated Islanding and Reconnection

Automated islanding and reconnection is achieved by automated separation and subsequent reconnection (autonomous synchronization) of an independently operated portion of the T&D system (i.e., microgrid) from the interconnected electric grid. A microgrid is an integrated energy system consisting of interconnected loads and distributed energy resources which, as an integrated system, can operate in parallel with the grid or as an island.

2.4.4.1 DOE SGCT Function to Benefit Rationale

A microgrid is an integrated energy system consisting of interconnected loads and distributed energy resources which, as an integrated system, can operate in parallel with the grid or as an island. This disconnection and reconnection of the microgrid and the interconnected electric grid would be done automatically as needed based on grid conditions. This function leads to three benefits:

- Reduced Sustained Outages – Automated islanding and reconnection means portions of the system that include distributed generation can be isolated from areas with excessive damage. Customers within the island, or microgrid, will be served by the distributed generation until the utility can restore service to the area. Only the customers in the island experience reduced outage time from this improved reliability. While the outage may affect wide areas and large numbers of customers, the island will most likely be no larger than a single distribution feeder (i.e., < 5,000 customers) or smaller.
- Reduced Major Outages – Automated islanding and reconnection means portions of the system that include distributed generation can be isolated from areas with excessive damage. Customers within the island, or microgrid, will be served by the distributed generation until the utility can restore service to the area. Only the customers in the island experience reduced outage time from this improved reliability. While the outage

may affect wide areas, and large numbers of customers, the island will most likely be no larger than a single distribution feeder (i.e., < 5,000 customers) or smaller.

- Reduced Restoration Cost – When an outage event occurs, customers in the island who would have otherwise experienced an outage will not experience a service interruption. Therefore, the restoration area that crews need to attend to will be reduced which will reduce the number of crews needed to restore power and reduce costs.

2.4.4.2 Feeder Islanding with Grid Battery

KCP&L Technology Demonstration Plan

A. Description

A 1.0 MWh, 1.0 MW-capable grid-connected Battery Energy Storage System will be installed at the Midtown Substation with direct interconnect to a single radial 13.2 kV circuit, immediately downstream of the substation transformer. DMS based battery control functions will be implemented to allow the distribution grid operator to put the BESS in Islanding mode and discharge the battery while a portion of the circuit is disconnected from the grid. Once the BESS is placed in Islanding mode, it will maintain power to the isolated section until grid power is restored or the battery is fully discharged.

B. Expected Results

The technical demonstration of the grid connected battery in this application is expected to yield the following:

- During a scheduled, controlled outage to the circuit, demonstrate that the BESS can restore power to customers after a brief outage.
- When grid power is restored, the BESS will automatically synchronize to the grid and seamlessly connect back to grid power without a second outage.

C. Relevant Impact Metrics

The Technical Demonstration of this application will not contribute to any Impact Metrics.

D. Benefits Analysis Method/Factors

The Technical Demonstration of the use of the BESS in this application will not contribute to the project Benefits Analysis.

E. Baseline Data & Control Groups

The Technical Demonstration of this application does not require any Baseline Data or the establishment of any Control Groups.

F. Testing Method/Methodology

The following points provide an overview of how the technical demonstration of this application will be accomplished:

- KCP&L will arrange a scheduled outage, for all customers on the feeder serving the BESS, at a time that will have minimal customer impact.
- The Grid Operator will open the feeder breaker creating a feeder outage.
- The Grid Operator will open the source side Recloser and the BESS will activate in "Islanding Mode" restoring power to customers downstream from the recloser.
- The BESS will be allowed to sustain power to customers for a period of time.
- The Grid Operator will close the feeder breaker restoring power to the source side of the recloser.

- The BESS will perform a sync-check and adjust BESS power output to synchronize the islanded section to the grid.
- Once the Islanded section is in-sync with the grid the BESS will close the recloser and discontinue discharge.

G. Analytical Method/Methodology

The Technical Demonstration of this application does not require any analytical calculations.

2.4.5 Diagnosis and Notification of Equipment Condition

Diagnosis and notification of equipment condition is defined as online monitoring and analysis of equipment, its performance, and operating environment in order to detect abnormal conditions (e.g., high number of equipment operations, temperature, or vibration). Asset managers and operations personnel can then be automatically notified to respond to conditions that increase the probability of equipment failure.

2.4.5.1 DOE SGCT Function to Benefit Rationale

Some equipment such as transformers and circuit breakers are critical to providing electric service to customers. Utilities test and maintain this equipment periodically in an effort to ensure that it operates reliably over a long service life. Because of the large amount of equipment, and the labor intensity of taking measurements and analyzing results, testing and maintenance can be very expensive, and may fail to identify critical equipment conditions before they lead to failure.

This function is the online monitoring and analysis of equipment, its performance and operating environment to detect abnormal conditions (e.g., high number of equipment operations, temperature, gas production or vibration). As a result, the function enables the equipment to automatically notify asset managers and operations to respond to a condition that increases a probability of equipment failure. This function results in seven benefits:

- Reduced Equipment Failures – Monitoring equipment "continuously" and receiving reports of its condition will help utilities identify potential trouble before it worsens and leads to failure.
- Reduced Distribution Equipment Maintenance Cost – The cost of sending technicians into the field to check equipment condition is high. Moreover, to ensure that they maintain equipment sufficiently and identify failure precursors, some utilities may conduct equipment testing and maintenance more often than is necessary. Online diagnosis and reporting of equipment condition would reduce or eliminate the need to send people out to check equipment.
- Reduced Sustained Outages – Some equipment failures cause outages, as well as environmental damage such as fires and spills. The time to restore power can be significant depending on the difficulty of the replacement, and the time it takes to obtain a replacement device. By utilizing online diagnosis and reporting of equipment condition, utilities could identify equipment problems before they cause outages.
- Reduced Restoration Costs – Outages caused by equipment failure will require restoration, and the utility will incur costs as a result. In some cases, the utility may pay a premium for the equipment and labor needed to restore service on short notice.
- Reduced CO_2 Emissions – Fewer truck rolls for switching means less fuel consumed by a service vehicle or line truck and leads to reduced emissions.
- Reduced SOx, NOx, and PM-2.5 Emissions – Fewer truck rolls for switching means less fuel consumed by a service vehicle or line truck and leads to reduced emissions.

- Reduced Oil Usage – Fewer truck rolls for equipment replacement means less fuel consumed by a service vehicle or line truck and leads to reduced oil consumption.

2.4.5.2 Substation Protection Automation

KCP&L Technology Demonstration Plan

A. Description

An IEC 61850 compliant substation communication controller and substation protection network will be installed in the Midtown Substation along with various other component upgrades to enable substation protection automation. Component upgrades will include the replacement of electromechanical relays with intelligent electronic relays and the deployment of enhanced protection schemes. All new relays will communicate directly with the substation controller. The substation protection network will provide distributed intelligence at the substation that will enable execution of automated protection operations based on feedback from real-time monitoring of transformers, relays, cap banks, and other field equipment.

B. Expected Results

The technical demonstration of the Substation Protection Automation is expected to yield the following:

- Substation Protection Automation will reduce operation and maintenance costs compared to the electromechanical relays.
- Automated actions based on real-time feedback will also help prevent component failures or route power around component failures within the substation, thus improving reliability and further reducing operation and maintenance costs.
- Implementation in accordance with IEC 61850 will provide experience and learning for the industry.
- Monitoring of all substation equipment will provide better operating data for utility decision making.

C. Relevant Impact Metrics

The Technical Demonstration of this application will not contribute to any Impact Metrics.

D. Benefits Analysis Method/Factors

This Technical Demonstration will not contribute to the project Benefits Analysis.

E. Baseline Data & Control Groups

The Technical Demonstration of this application does not require any Baseline Data or the establishment of any Control Groups.

F. Testing Method/Methodology

The following points provide an overview of how the technical demonstration of this application will be accomplished:

- Electronic relays will be deployed in Midtown Substation in 2010.
- IEC61850 GOOSE protection schemes will be deployed on the substation relays via CID files. GOOSE will be enabled via a setting in the relay settings files in December 2013.
- The relays will begin collecting information from the cross triggering GOOSE scheme.
- The SG team and KCP&L engineers will use the event information for enhanced visibility into substation events and real time device information.

G. Analytical Method/Methodology

The Technical Demonstration of this application does not require any analytical calculations.

2.4.5.3 Asset Condition Monitoring

KCP&L Technology Demonstration Plan

A. Description

An asset condition monitoring and reporting infrastructure will be installed for all key substation and field devices throughout the SGDP Area. The asset condition monitoring and reporting infrastructure to be implemented includes enhanced equipment sensors and control capabilities, real-time condition monitoring and alarming capabilities in the DMS, and the DMS-HIS for archival of reported conditions for later analysis.

B. Expected Results

The operational demonstration of this application is expected to yield the following:

- Analysis of condition monitoring data from currently available industry equipment controls will provide experience and learning for the industry.
- Implementation of report-by-exception condition monitoring data from current industry equipment controls will provide experience and learning for the industry.
- Demonstrate how remote asset condition reporting can reduce operation and maintenance costs as conditions can be determined remotely in real time.
- Record any actions based on real-time feedback that were used to help prevent component failures, thus improving reliability and further reducing operation and maintenance costs.

C. Relevant Impact Metrics

The Operational Testing of this application will contribute to these Impact Metrics.

Distribution	Feeder Aggregated Average Real Load (MW)
Distribution	Feeder Aggregated Average Reactive Load (MVAR)
Distribution	Feeder Hourly Load Curves (MW)
Distribution	Feeder Hourly Reactive Load Curves (MVAR)
Distribution	Avoided Distribution Losses (MWh)

At each reporting milestone, operational test, or demonstration period, data will be compared to baseline data to determine a quantified impact. Quantified impacts measured will be reported in semi-annual impact metric reports.

D. Benefits Analysis Method/Factors

The DOE SGCT will be used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits will be quantified.

- Reduced Equipment Failures
- Reduced T&D Equipment Maintenance Cost

Benefits will be calculated using SGCT formulas. The following factors will be measured, projected or calculated during the application operation and/or demonstration.

Reduced Equipment Failures

- Capital Replacement of Failed Equipment ($)

Reduced T&D Equipment Maintenance Cost

- Reduced Distribution Equipment Maintenance Cost ($)

E. Baseline Data & Control Groups

The Technical Demonstration of this application does not require any Baseline Data or the establishment of any Control Groups.

F. Testing Method/Methodology:

The following points provide an overview of how the operational testing for this application will be accomplished:

- A fiber substation protection will be deployed at Midtown Substation to enable communications to substation devices, and a Tropos wireless mesh network will be deployed throughout the SGDP area to enable communications to field devices.
- Intelligent Electronic Devices (IEDs) will be deployed in Midtown Substation and along the 11 designated smart grid feeders extending from Midtown Substation.
- Data from the IEDs will be reported to a centralized data concentrator, and then sent to the DMS or DCADA for monitoring purposes.
- The DMS or DCADA will utilize the substation and field device data as inputs to First Responder applications, and will send control commands back out to the devices.

G. Analytical Method/Methodology

The Technical Demonstration of this application does not require any analytical calculations.

2.4.5.4 Substation Hierarchical Control

KCP&L Technology Demonstration Plan

A. Description

An IEC 61850 compliant substation automation network will be installed in the Midtown Substation along with automation control components to enable robust distributed automation functionality. The automation control components to be implemented include a substation communication controller for both substation and field devices; distributed automation controllers; and an HMI for local monitoring and control of substation devices. The substation automation network will provide distributed intelligence at the substation that will enable execution of automated control operations based on feedback from real-time monitoring of transformers, relays, cap banks, and other field equipment installed throughout the circuits.

B. Expected Results

The Technical Demonstration of this application is expected to yield the following:

- Evaluation of existing control system technologies to implement a distributed hierarchical control systems will provide experience and learning for the industry.
- Remote monitoring and operation of all substation equipment from a single location within the substation will provide an increased level of safety for the field operator.

C. Relevant Impact Metrics

The Technical Demonstration of this application will not contribute to any Impact Metrics.

D. Benefits Analysis Method/Factors

The Technical Demonstration of this application will not contribute to the project Benefits Analysis.

E. Baseline Data & Control Groups

The Technical Demonstration of this application does not require any Baseline Data or the establishment of any Control Groups.

F. Testing Method/Methodology:

The following points provide an overview of how the technical demonstration of this application will be accomplished:

- A fiber substation protection network will be deployed at Midtown Substation to enable communications to substation devices, and a Tropos wireless mesh network will be deployed throughout the SGDP area to enable communications to field devices.
- Intelligent Electronic Devices (IEDs) will be deployed in Midtown Substation and along the 11 designated smart grid feeders extending from Midtown Substation.
- Data from the IEDs will be reported to a centralized data concentrator, and then sent to the substation DCADA and HMI for monitoring purposes.
- Verify that the DMS and the DCADA take similar action when given the same device statuses, depending on which system is in control of the substation.
- Verify that the HMI correctly reflects the substation device data in addition to the network status data.
- Verify that the user can control substation devices from the HMI.

G. Analytical Method/Methodology

The Technical Demonstration of this application does not require any analytical calculations.

2.4.6 Real-Time Load Measurement and Management

This function provides real-time measurement of customer consumption and management of load through AMI systems (smart meters, two-way communications) and embedded appliance controllers that help customers make informed energy use decisions via real-time price signals, time-of-use (TOU) rates, and service options.

2.4.6.1 DOE SGCT Function to Benefit Rationale

Devices such as smart meters and appliance controllers can monitor the energy use of customer loads over the course of the day. These same devices can be used to help customers respond to pricing signals so that system load can be managed as a resource. Real-time measurement of customer consumption and management of load through AMI systems and embedded appliance controllers help customers make informed energy use decisions via real-time price signals, time-of-use (TOU) rates, and service options. This function can provide eleven benefits:

- Reduced Ancillary Service Cost – The increased resolution of customer load data will improve load models and help grid operators to better forecast energy supply requirements. Improved forecasts, along with the ability to reduce customer demand effectively during critical periods, could reduce reserve margin requirements.
- Deferred Distribution Capacity Investments – Load growth and feeder reconfiguration can lead to increased loading on lines and transformers, to the point where distribution capacity investments become necessary. Smart meters and AMI will allow utilities to monitor customer loads and voltage more closely, and provide a platform for sending pricing signals that could influence consumption patterns. This could enable utilities to better anticipate and monitor feeder loading, and operate the distribution system closer to its limits. For example, it could be possible for a utility to delay building a new distribution feeder for one or more years without running the risk of low voltage problems. Each year that a capital investment can be deferred can yield a significant savings in the utility's revenue requirement (equal to the capital carrying charge of the upgrade). Therefore, Real-Time Load Measurement and Control could yield direct savings based on the time that it could postpone a capital investment.
- Reduced Meter Reading Cost – The data from smart meters can be automatically uploaded to a central MDM system. This avoids the need to read meters manually, reducing the cost of performing this function.
- Reduced Electricity Theft – Smart meters can typically detect tampering. Moreover, a meter data management system can analyze customer usage to identify patterns that could indicate diversion.
- Reduced Electricity Losses – Peak load tends to affect delivery losses more than average load, and managing this peak could lead to improvements in electricity delivery efficiency. Being able to manage customer demand will give the utility the capability of reducing peak load, and thereby reduce delivery losses.
- Reduced Sustained Outages – Today, most utilities rely on customer calls to identify power outages and customer service representatives to enter the outage information into a computer system. Outage management systems have been designed to interpret this outage information and estimate the location of the fault based on the information. AMI systems perform outage detection based on the status of smart meters. This should improve the accuracy of outage notification, and reduce the time to restore service.
- Reduced Major Outages – Major outages occur as a result of hurricanes, ice storms, or other natural events that affect large geographical areas and tens of thousands of customers or more. Restoring electric service following these events typically takes a few

days or more because of the massive damage that must be repaired on the distribution system. When utility crews move through an area making repairs to the distribution system, there are times when some customers fail to have their service restored because of unseen/overlooked damage. In such cases, when service is restored in the area, the utility crews may have left the area before the utility can receive a follow-up call from the customer saying that they are still without service. This means that the customer will be without service until a crew has time to come back to the area to fix the problem, and outage minutes will continue to increase. With AMI, utilities will be able to identify those customers who remain without power after the utility believes that power should be restored. This should make it easier to get a crew back to the location more quickly, and reduce the amount of time that the customer is outaged.

- Reduced Restoration Cost – AMI systems are being developed to perform outage detection based on the status of smart meters. This should improve the accuracy of outage notification and reduce the time to restore service. Reduced restoration times translate into reduced restoration costs because power can be restored with fewer restoration crew labor hours.
- Reduced CO_2 Emissions – Manual meter reading requires that a person drive from meter to meter once each billing cycle. This produces CO_2 emissions from the vehicle. Eliminating the vehicle miles traveled eliminates the associated emissions.
- Reduced SOx, NOx, and PM-2.5 Emissions – Polluting emissions associated with vehicle miles travelled are eliminated.
- Reduced Oil Usage – Eliminating vehicle miles traveled with automatic meter reading eliminates the associated fuel consumption.

2.4.6.2 Automated Meter Reading

KCP&L Operational Test Plan
A. Description AMI will be deployed to the entire KCP&L SmartGrid Demonstration area. Deployment will include the installation of smart meters (capable of two-way communications, interval metering, and remote connect/disconnect) at approximately 14,000 residential, commercial, and industrial customers. Meters will measure, store, and wirelessly transmit 15-minute interval energy usage data to a central MDM system where it will be available to other KCP&L systems. Communications between meters and the MDM will be accomplished through a dedicated RF-mesh Field Area Network (FAN) and KCP&L's private Wide Area Network (WAN).
B. Expected Results This operational demonstration of the AMI is expected to yield the following: • AMI will capture meter reading at 15-minute intervals as opposed to the daily reads currently accomplished by KCP&L's AMR system. • AMI will provide the interval metering and communication infrastructure required for many of the SGDP applications. • AMI will demonstrate improved operational performance over the legacy AMR system, including the reporting of alarms/alerts indicating possible operational issues.
C. Relevant Impact Metrics The Operational Testing of this application will contribute to these Impact Metrics.

AMI and CSA	Hourly Customer Electricity Usage – Res./Com./Ind. (kWh)
AMI and CSA	Monthly Customer Electricity Usage – Res./Com./Ind. (kWh)
AMI and CSA	Peak Load – Total (kW)
AMI and CSA	Peak Load by Customer Class – Res./Com./Ind. (kW)
AMI and CSA	Number of Meter Tamper Detections
AMI and CSA	Meter Data Completeness (%)
AMI and CSA	Meters Reporting Daily (%)

At each reporting milestone, operational test, or demonstration period, data will be compared to baseline data to determine a quantified impact. Quantified impacts measured will be reported in semi-annual impact metric reports.

D. Benefits Analysis Method/Factors

The DOE SGCT will be used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits will be quantified.

- Reduced Meter Reading Costs
- Reduced Electricity Theft
- Reduced CO_2 Emissions

Benefits will be calculated using SGCT formulas. The following factors will be measured, projected or calculated during the application operation and/or demonstration.

Reduced Meter Reading Costs

- Route meter read benefits will not be realized as KCP&L already uses AMR technology
- Avoided Meter Operations Costs ($) (FSP labor performing on-demand Meter Reads)

Reduced Electricity Theft

- Number of Meter Tamper Detections (#) by customer class

Reduced CO_2 Emissions

- Number of Meter Reading Operations (avoided)

E. Baseline Data & Control Groups

The Operational Analysis of this of this application does not require any Baseline Data or the establishment of any Control Groups.

F. Testing Method/Methodology:

The following points provide an overview of how the operational testing for this application will be accomplished:

- AMI interval metering that will be deployed in late 2010 to replace legacy AMR meters for all customers within the SGDP area.
- AMI meter reading performance metrics tracking will be captured by the AHE.
- AMI meter reads and events will be processed by the AMI Head-End and sent to the MDM for analysis, reporting, and archival.

G. Analytical Method/Methodology

The following points provide an overview of the analytical methods that will be used to evaluate the impact and benefits of this application:

- AMI interval load data for all customers within the Project area will be extracted from the MDM System through KCP&L's DMAT. The DMAT has built in functionality that will enable the aggregation and calculation of hourly load profiles by customer class.

2.4.6.3 Remote Meter Disconnect/Reconnect

KCP&L Operational Test Plan

A. Description

AMI will be deployed to the entire KCP&L SmartGrid Demonstration area, approximately 14,000 residential and commercial customers. Nearly all of the AMI meters will have an integral switch capable of remote connect/disconnect capabilities. Integration between CIS, MDM, and the AMI will be implemented to automate remote connect/disconnect functionality to support customer requested connect/disconnect orders. Remote connect/disconnects for non-payment will not be implemented, due to current Public Service Commission requirements for the utility to attempt in-person contact prior to disconnect for non-payment.

B. Expected Results

This operational demonstration of the AMI is expected to yield the following:

- AMI two-way communications will enable KCP&L to remotely connect or disconnect customers from the KCP&L service center.
- Truck rolls and Field Service Professional labor will be avoided for each remote connect/disconnect operation.

C. Relevant Impact Metrics

The Operational Testing of this application will contribute to these Impact Metrics.

AMI and CSA	Truck Rolls Avoided
AMI and CSA	Meter Operations Vehicle Miles Avoided
AMI and CSA	Avoided CO_2 Emissions (tons)

At each reporting milestone, operational test, or demonstration period, data will be compared to baseline data to determine a quantified impact. Quantified impacts measured will be reported in semi-annual impact metric reports.

D. Benefits Analysis Method/Factors

The DOE SGCT will be used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits will be quantified.

- Reduced Meter Reading Costs
- Reduced CO_2 Emissions

Benefits will be calculated using SGCT formulas. The following factors will be measured, projected or calculated during the application operation and/or demonstration.

Reduced Meter Reading Costs

- Avoided Meter Operations Costs ($) (FSP labor performing Connect/Disconnects)

Reduced CO_2 Emissions

- Avoided Truck Rolls

E. Baseline Data & Control Groups

The Operational Analysis of this of this application does not require any Baseline Data or the establishment of any Control Groups.

F. Testing Method/Methodology:

The following points provide an overview of how the operational testing for this application will be accomplished:

- AMI interval metering that will be deployed in late 2010 to replace legacy AMR meters for all customers within the SGDP area.
- Integration between CIS, MDM, and the AMI Head End will be implemented to automate the remote service order (connect/disconnect) processes.
- Remote connect/disconnect performance metrics tracking will be captured by the CIS service order subsystem.

G. Analytical Method/Methodology

The following points provide an overview of the analytical methods that will be used to evaluate the impact and benefits of this application:

- Avoided truck-rolls will be determined based on the number of successful remote connect and disconnect operations performed.

2.4.6.4 Meter Outage Restoration

KCP&L Technology Demonstration Plan

A. Description

AMI will be deployed to the entire KCP&L SmartGrid Demonstration area, approximately 14,000 residential and commercial customers. Meters will wirelessly transmit power outage/restoration alerts via the AMI to a central MDM system where it will be available to the OMS and other KCP&L systems. The MDM and AMI will also provide for on-demand verification of meter power status via the two-way communication network.

B. Expected Results

The operational demonstration of the AMI is expected to yield the following:

- Meter outage/restoration alerts will be transported via the AMI and MDM systems and received and processed by the OMS.
- AMI and MDM provide the active meter status in response to Power Status Verification requests issued by the OMS.
- Improved outage response should result from this application, but since the SGDP systems are not used for production outage response; this benefit will not be measurable.

C. Relevant Impact Metrics

The Operational Testing of this application will contribute to these Impact Metrics.

AMI and CSA	SAIFI
AMI and CSA	SAIDI
AMI and CSA	CAIDI
AMI and CSA	Total Customers Served by SAIDI/SAIFI

At each reporting milestone, operational test, or demonstration period, data will be compared to baseline data to determine a quantified impact. Quantified impacts measured will be reported in semi-annual impact metric reports.

D. Benefits Analysis Method/Factors

The DOE SGCT will be used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits will be quantified.

- Reduced Sustained Outages

Benefits will be calculated using SGCT formulas. The following factors will be measured, projected or calculated during the application operation and/or demonstration.

Reduced Sustained Outages

- SAIDI (base &projected)

E. Baseline Data & Control Groups

The following historical system level reliability statistics will be available for analysis:

- System Average Interruption Frequency Index (SAIFI)
- System Average Interruption Duration Index (SAIDI)
- Customer Average Interruption Duration Index (CAIDI)

F. Testing Method/Methodology:

The following points provide an overview of how the technical demonstration of this application will be accomplished:

- AMI interval metering that will be deployed in late 2010 to replace legacy AMR meters for all customers within the SGDP area.
- Integration between AMI Head End, MDM, and the OMS will be implemented to process power outage/restoration event notifications and power status verification (request/reply) message flows.
- The SGDP DMS-OMS will process and record all power outage/restore notifications for the SGDP area in parallel to the production legacy OMS. The legacy OMS support all production outage restoration efforts.
- The project team will use the DMS-OMS to demonstrate benefit of using the PSV message flow to enhance outage restoration activities.

G. Analytical Method/Methodology

The Technical Demonstration of this application does not require any analytical calculations.

2.4.6.5 Demand Response Events

KCP&L Operational Test Plan

A. Description

The implementation of a Distributed Energy Resource Management System in conjunction with PCTs and other HAN connected devices will enable advanced utility utilization of demand response on the distribution system. The DERM will maintain a sophisticated distributed energy resource inventory and will be capable of forecasting, scheduling, selecting, and executing load control programs for all or select devices.

Two types of DR events will be considered for implementation and testing. First, for stand-alone PCTs communicating directly to the AMI, a DLC DR event will be issued through the AMI system. Second, for HAN connected PCTs and devices, a Pay for Participation (PFP) DR event will be considered for issuance through the HEMP/HAN infrastructure. In both cases, demand response events can be scheduled and executed system wide or can be isolated or grouped to affect only targeted circuits or sections of the distribution system to support reliability needs.

B. Expected Results

This operational demonstration is expected to yield the following:

- Implementation of DR events in accordance with OpenADR 2.0, IEC-61968-9, and ZigBee SEP 1.x will provide experience and education for the industry.
- DMS/DERM/HEMP/AHE/PCT integration will enable utility-controlled reduction in kW on the entire system or on select groups of PCTs.
- DMS/DERM/HEMP/HAN integration will enable customer managed (PFP) reduction in kW on the entire system or on selected groups of HAN connected PCTs and other devices, provided such integration falls within program definitions.
- An assessment of the ability of DERM/DMAT to post process AMI data to determine the level of demand reduction achieved by each event participant.

C. Relevant Impact Metrics

The Operational Testing of this application will contribute to these Impact Metrics.

AMI and CSA	Direct Load Control Available via AMI (MW)
AMI and CSA	Direct Load Control Dispatched at Peak via AMI (MW)

At each reporting milestone, operational test, or demonstration period, data will be compared to baseline data to determine a quantified impact. Quantified impacts measured will be reported in semi-annual impact metric reports.

D. Benefits Analysis Method/Factors

The DOE SGCT will be used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits will be quantified.

- Deferred Generation Capacity Investment
- Deferred Distribution Capacity Investment

Benefits will be calculated using SGCT formulas. The following factors will be measured, projected or calculated during the application operation and/or demonstration.

Deferred Generation Capacity Investment

- Demand Response Used at Annual Peak Time (MW)

Deferred Distribution Capacity Investment

- Demand Response Used at Distribution Peak Time (MW)

E. Baseline Data & Control Groups

AMI metering that is deployed for all customers, circuits, and distributed energy resources within the SGDP area. The following usage data will be available for baselines:

- 15 minute interval load data of all customers.

The following system level energy production data will be available for analysis:

- Historical and current hourly system energy production load profile data.
- Historical weather adjusted system energy production load profile data.

Since the DR programs will be event-based, the DERM will construct baseline profiles for each program participant from available interval AMI metering data.

F. Testing Method/Methodology:

The following points provide an overview of how the technical demonstration of this application will be accomplished:

- DERM includes DR assets deployed by Smart End use programs
- User is capable of creating programs for thermostats and HANs in the DERM
- DMS identified potential overload or company system peak events and calls on the DERM for assistance
- DERM evaluates options and creates DR events
- DERM dispatches DR events
- DERM scheduled and executed DR events will be tracked by the DERM system and participant compliance will be tracked by the HEMP system
- Post event analysis to determine DR load reduction

G. Analytical Method/Methodology

The following points provide an overview of the analytical methods that will be used to evaluate the impact and benefits of this application:

- Interval load data for customers participating in DERM DR programs will be measured through KCP&L's AMI system deployed as part of the Project.
- The DERM will construct baseline profiles for each program participant from available interval AMI metering data.
- DERM scheduled and executed DR events will be tracked by the DERM system and participant compliance will be tracked by the HEMP system.
- The DERM will perform after-the-fact analysis of each DR event to determine the level of demand reduction achieved by each event participant.
- The DERM analysis will be accomplished by directly comparing event day load profiles for each participating circuit to baseline load profiles.
- The difference at each daily time point should closely reflect DERM forecasted demand reduction potential throughout the event.

2.4.7 Customer Electricity Use Optimization

Customer electricity use optimization is possible if customers are provided with information to make educated decisions about their electricity use. Customers should be able to optimize toward multiple goals such as cost, reliability, convenience, and environmental impact.

2.4.7.1 DOE SGCT Function to Benefit Rationale

A key characteristic of the smart grid is that it motivates and includes the customer. This function enables customers to observe their consumption patterns and modify them according to their explicit or implicit objectives. These could include minimizing cost, maximizing reliability, or purchasing renewable energy, among others. Nine benefits are provided:

- Deferred Generation Capacity Investments – Utilities build generation, transmission, and distribution with capacity sufficient to serve the maximum amount of load that planning forecasts indicate. The trouble is, this capacity is only required for very short periods each year, when demand peaks. The smart grid can help reduce peak demand and flatten the load curve by giving customers the information and incentives to better manage their electricity usage. This should translate into lower infrastructure investments by utilities and cheaper electricity for customers.

- Deferred Transmission Capacity Investments – See Deferred Generation Capacity Investments, above.
- Deferred Distribution Capacity Investments – See Deferred Generation Capacity Investments, above.
- Reduced Electricity Cost – The information provided by smart meters and in-home displays may encourage customers to alter their usage patterns (demand response with price signals or direct load control), or conserve energy generally because they can see how much it costs and alter their behavior. Changes in usage can result in reductions in the total cost of electricity.
- Reduced Ancillary Service Cost – The ability to reduce customer demand effectively during critical periods could reduce reserve margin requirements.
- Reduced Congestion Cost – If customers have tools to manage their energy use, this could lead to a more conservative use of electricity especially at peak times, so less electricity must be passed through the T&D lines, which reduces congestion.
- Reduced Electricity Losses – Higher line loading tends to affect delivery losses more than average load, and managing this peak could lead to improvements in electricity delivery efficiency. If the customer is aware of their electricity use and shifts it to Off-Peak times, the losses may be reduced.
- Reduced CO_2 Emissions – Increased customer awareness of electricity use may lead to conservation which, in turn would decrease the electricity generation required and the associated emissions. Furthermore, customer pricing and incentives can be used to optimize the load shape (especially at peak) leading to increased system efficiency which will reduce the amount of generation required to serve load. Assuming that the generation is fossil-based, emissions will be reduced.
- Reduced SOx, NOx, and PM-2.5 Emissions – Increased customer awareness of electricity use may lead to conservation which, in turn would decrease the electricity generation required and the associated emissions. Furthermore, customer pricing and incentives can be used to optimize the load shape (especially at peak) leading to increased system efficiency which will reduce the amount of generation required to serve load. Assuming that the generation is fossil-based, emissions will be reduced.

2.4.7.2 Historical Interval Usage Access

KCP&L Operational Test Plan

A. Description

All customers in the SGDP will be provided access to the KCP&L-hosted Home Energy Management Portal, a website that presents customers with various tools with which they may visualize and analyze their detailed energy usage history. The HEMP website will be accessible through KCP&L's AccountLink website and provides customer with:

- Historical 15 minute interval usage information from their smart meter presented within user-friendly visualizations allowing them to evaluate their energy consumption
- A daily bill update that provides Bill to Date, days remaining in billing period, and an Estimated Bill Projection based on current consumption patterns.
- Information, tools, advice, and programs to manage and reduce electricity costs.

B. Expected Results

With the additional information that the HEMP provides the consumer, it is expected that:

- Customers will use the historical interval metering data available on the HEMP to better understand their total energy consumption and patterns.
- Customers will find the Bill to Date and Estimated Bill information provided on the HEMP useful in managing their energy usage costs.
- HEMP users will reduce their overall energy consumption. Other studies have shown that HEMP users may reduce their overall energy consumption by as much as 1-5%.

C. Relevant Impact Metrics

The Operational Testing of this application will contribute to these Impact Metrics.

AMI and CSA	Hourly Customer Electricity Usage – Res./Com./Ind. (kWh)
AMI and CSA	Monthly Customer Electricity Usage – Res./Com./Ind. (kWh)

At each reporting milestone, operational test, or demonstration period, customer usage data will be reported in semi-annual impact metric reports.

D. Benefits Analysis Method/Factors

The DOE SGCT will be used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits will be quantified.

- Reduced Electricity Costs

Benefits will be calculated using SGCT formulas. The following factors will be measured, projected or calculated during the application operation and/or demonstration.

Reduced Electricity Costs (Consumer)

- Reduced Total Annual Electric Consumption (kWh) by customer class.

E. Baseline Data & Control Groups

AMI metering that is deployed for all customers, circuits, and distributed energy resources within the SGDP area. The following usage data will be available for baselines:

- 15 minute interval load data of all customers.
- Average hourly interval load data by customer class.

Legacy AMR metering is available for all other customers in the Kansas City metro area. The following usage data will be available for baselines and control groups:

- Daily kWh usage data for all customers
- Daily kWh usage data for all customers in the project area prior to AMI
- 15 minute interval load data for select control group customers outside the project area

Impacts to customer electricity usage and cost for HEMP users will be quantified through the use of a control group:

- Control group will consist of interval and daily load profile data (kWh) for selected customers outside the project area but of similar demographic and geographic vicinity
- Control group load profiles will be captured through the legacy AMR interval metering with increased data reporting

F. Testing Method/Methodology:

The following points provide an overview of how the operational testing for this application will be accomplished:

- 15 minute interval load data will be collected for all HEMP participants throughout the project period through KCP&L's AMI system deployed as part of the Project.
- All interval meter data will be stored in KCP&L's MDM System and DMAT.
- At the conclusion of the operational period (through October 2014), HEMP participants interval and aggregate usage data will be compared to coincident control group interval and aggregate usage data.

G. Analytical Method/Methodology

The following points provide an overview of the analytical methods that will be used to evaluate the impact and benefits of this application:

- Load profiles of HEMP participants will be compared to those of select control group customers on an hourly, daily, and monthly basis to evaluate the average or typical impact HEMP exhibits on measured participant energy usage. Calculated impacts will be assessed for statistical significance.
- Willing HEMP participants will be surveyed by a third party to solicit feedback on their experience using the HEMP website to determine their primary application of the tool and information provided.

2.4.7.3 In-Home Display

KCP&L Operational Test Plan

A. Description

All customers in the SGDP will be offered, at no cost, an In-Home Display (IHD). This IHD is a portable, digital display device that communicates with a customer's AMI meter via ZigBee and provides real-time energy usage monitoring. This enables them to gain improved awareness and thus better understand their personal energy usage and associated costs. The IHD essentially provides customers with a real-time "speedometer" and "odometer" for electric use in their home – giving them both current consumption rate information as well as access to visualize historical usage information.

The IHD will provide customers with:

- Real-time energy usage and cost information from their smart meter.
- Current price of energy based on their rate, current usage block, and/or TOU period.
- Daily bill update that provides Bill to Date, days remaining in billing period, and an Estimated Bill Projection based on current consumption patterns.
- Demand Response messages asking them to reduce load during peak times.
- Other Informational messages sent from the utility.

B. Expected Results

With the additional information that the IHD provides the consumer, it is expected that:

- Customers will use the real-time metering data available on the IHD to better understand their total energy consumption patterns and those of individual appliances.

- Customers will find the Bill to Date and Estimated Bill information provided on the IHD useful in managing the energy usage costs.
- IHD users will reduce their overall energy consumption. Other studies have shown that IHD users may reduce their overall energy consumption by as much as 2-7%.
- IHD user will voluntarily participate in DR events when notified via the IHD.

C. Relevant Impact Metrics

The Operational Testing of this application will contribute to these Impact Metrics.

AMI and CSA	Hourly Customer Electricity Usage – Res./Com./Ind. (kWh)
AMI and CSA	Monthly Customer Electricity Usage – Res./Com./Ind. (kWh)

At each reporting milestone, operational test, or demonstration period data customer usage data will be compiled and reported in semi-annual impact metric reports.

D. Benefits Analysis Method/Factors

The DOE SGCT will be used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits will be quantified.

- Reduced Electricity Costs

Benefits will be calculated using SGCT formulas. The following factors will be measured, projected or calculated during the application operation and/or demonstration.

Reduced Electricity Costs (Consumer)

- Reduced Total Annual Electric Consumption (kWh) by customer class.

E. Baseline Data & Control Groups

AMI metering that is deployed for all customers, circuits, and distributed energy resources within the SGDP area. The following usage data will be available for baselines:

- 15 minute interval load data of all customers.
- Average hourly interval load data by customer class.

Legacy AMR metering is available for all other customers in the Kansas City metro area. The following usage data will be available for baselines and control groups:

- Daily kWh usage data for all customers
- Daily kWh usage data for all customers in the project area prior to AMI
- 15 minute Interval load data for select control group customers outside the project area

Impacts to customer electricity usage and cost for IHD users will be quantified through the use of a control group:

- Control group will consist of interval and daily load profile data (kWh) for selected customers outside the project area but of similar demographic and geographic vicinity.
- Control group load profiles will be captured through the legacy AMR interval metering with increased data reporting.
- Baseline data for HAN users with regards to demand response events will also consist of weather-adjusted previous or proxy day load profiles.

F. Testing Method/Methodology:

The following points provide an overview of how the operational testing for this application will be accomplished:

- 15 minute interval load data will be collected for all IHD participants throughout the project period through KCP&L's AMI system deployed as part of the Project
- All interval meter data will be stored in KCP&L's MDM System and DMAT
- At the conclusion of the operational period (through October 2014), IHD participants interval and aggregate usage data will be compared to coincident control group interval and aggregate usage data

G. Analytical Method/Methodology

The following points provide an overview of the analytical methods that will be used to evaluate the impact and benefits of this application:

- Load profiles of IHD participants will be compared to those of select control group customers on an hourly, daily, and monthly basis to evaluate the average or typical impact IHD exhibits on measured participant energy usage. Calculated impacts will be assessed for statistical significance.
- For impact during DR events, load profiles of IHD participants on event days will also be compared to previous or proxy day load profiles for the same customer. Previous or proxy days will be days without DR events.
- Willing IHD participants will be surveyed by a third party to solicit feedback on their experience using the IHD to determine their primary application of the tool and information provided.

2.4.7.4 Home Area Network

KCP&L Operational Test Plan

A. Description

All customers in the SGDP, that meet program criteria will be offered, at no cost, a Home Area Network. The HAN consists of a broadband gateway device communicating to the KCP&L meter and to numerous energy devices in customer home. Program participants will also receive a compatible PCT and two compatible load control switches. The PCT will be enrolled in the pilot utility DR program.

The gateway device will get real-time usage information directly from the customer's smart meter and will also establish communications between the utility HEMP via the customer supplied internet connection. The combination of HEMP/HAN functionality will provide customers:

- With a user-friendly visualization of real-time usage data from their smart meter via the HEMP and allow them to make energy usage decisions based on real-time usage and cost information
- The ability to remotely control their PCT and other energy consuming appliances via the load control switch(es) to manage their daily energy consumption

Additionally, the HAN will provide the capability for all HAN connected devices to participate in demand response events based on customer preferences.

B. Expected Results

With the additional control and information that the HAN provides the consumer, it is expected that:

- Customers will use the information on the HEMP to better understand their total energy consumption and patterns
- HAN users will utilize the device communications and control provided via the HAN to manage their energy consuming devices
- HAN users will utilize the information and control provided via the HEMP to be effective in managing their energy usage costs

For those that choose to combine HAN control capabilities with new voluntary TOU rate options, it is expected that the HAN users will

- Shift load to off peak times
- Voluntarily allow HAN-connected devices to participate in DR events

Additionally, the HAN deployments will be used to demonstrate customer incented DR events.

C. Relevant Impact Metrics

The Operational Testing of this application will contribute to these Impact Metrics.

AMI and CSA	Hourly Customer Electricity Usage – Res./Com./Ind. (kWh)
AMI and CSA	Monthly Customer Electricity Usage – Res./Com./Ind. (kWh)

At each reporting milestone, operational test, or demonstration period data customer usage data will be compiled and reported in semi-annual impact metric reports.

D. Benefits Analysis Method/Factors

The DOE SGCT will be used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits will be quantified.

- Deferred Generation Capacity Investments
- Reduced Electricity Costs

Benefits will be calculated using SGCT formulas. The following factors will be measured, projected or calculated during the application operation and/or demonstration.

Deferred Generation Capacity Investments

- Customer Load Reduction at Annual Peak Time (MW)

Reduced Electricity Costs (Consumer)

- Reduced Total Annual Electric Consumption (kWh) by customer class.

E. Baseline Data & Control Groups

AMI metering that is deployed for all customers, circuits, and distributed energy resources within the SGDP area. The following usage data will be available for baselines:

- 15 minute interval load data of all customers.
- Average hourly interval load data by customer class.

Legacy AMR metering is available for all other customers in the Kansas City metro area. The following usage data will be available for baselines and control groups:

- Daily kWh usage data for all customers
- Daily kWh usage data for all customers in the project area prior to AMI
- 15 minute Interval load data for select control group customers outside the project area

Impacts to customer electricity usage and cost for HAN users will be quantified through the use of a control group:

- Control group will consist of interval and daily load profile data (kWh) for selected customers outside the project area but of similar demographic and geographic vicinity.
- Control group load profiles will be captured through the legacy AMR interval metering with increased data reporting.
- Baseline data for HAN users with regards to demand response events will also consist of weather-adjusted previous or proxy day load profiles

F. Testing Method/Methodology:

The following points provide an overview of how the operational testing for this application will be accomplished:

- 15 minute interval load data will be collected for all HAN participants throughout the project period through KCP&L's AMI system deployed as part of the Project
- All interval meter data will be stored in KCP&L's MDM System and DMAT
- At the conclusion of the operational period (through October 2014), HAN participants interval and aggregate usage data will be compared to coincident control group interval and aggregate usage data

G. Analytical Method/Methodology

The following points provide an overview of the analytical methods that will be used to evaluate the impact and benefits of this application:

- Load profiles of HAN participants will be compared to those of select control group customers on an hourly, daily, and monthly basis to evaluate the average or typical impact HAN exhibits on measured participant energy usage. Calculated impacts will be assessed for statistical significance.
- For impact during DR events, load profiles of HAN participants on event days will also be compared to previous or proxy day load profiles for the same customer. Previous or proxy days will be days without DR events.
- Willing HAN participants will be surveyed by a third party to solicit feedback on their experience using the HAN to determine their primary application of the tool and information provided.

2.4.7.5 Time-of-Use Rate

KCP&L Operational Test Plan

A. Description

All Residential customers in the SGDP will be offered the ability to participate in a pilot Time-of-Use (TOU) rate. While designed to be revenue neutral, the pilot TOU tariff provides significant incentive for customers to shift load from peak periods to Off-Peak periods due to a relatively large difference between peak and Off-Peak prices during the summer months. On this pilot TOU rate, during summer months, the peak energy price ($/kWh) is approximately six times greater than the Off-Peak price.

B. Expected Results

During the summer when the TOU rates are in effect, it is expected that TOU participants will:

- Shift load from peak to Off-Peak times
- Reduce their overall kWh consumption
- Achieve an overall reduction in their electricity bill

It is also expected that some TOU participants will also participate in IHD or HAN programs and that those dual participants may achieve greater savings than participants without devices.

C. Relevant Impact Metrics

The Operational Testing of this application will contribute to these Impact Metrics.

AMI and CSA	Hourly Customer Electricity Usage – Res./Com./Ind. (kWh)
AMI and CSA	Monthly Customer Electricity Usage – Res./Com./Ind. (kWh)

At each reporting milestone, operational test, or demonstration period data customer usage data will be compiled and reported in semi-annual impact metric reports.

D. Benefits Analysis Method/Factors

The DOE SGCT will be used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits will be quantified.

- Deferred Generation Capacity Investments
- Reduced Electricity Costs

Benefits will be calculated using SGCT formulas. The following factors will be measured, projected or calculated during the application operation and/or demonstration.

Deferred Generation Capacity Investments

- Customer Load Reduction at Annual Peak Time (MW)

Reduced Electricity Costs (Consumer)

- Reduced Total Annual Electric Consumption (kWh) by customer class.

E. Baseline Data & Control Groups

AMI metering that is deployed for all customers, circuits, and distributed energy resources within the SGDP area. The following usage data will be available for baselines::

- 15 minute interval load data of all customers.
- Average hourly interval load data by customer class

Legacy AMR metering is available for all other customers in the Kansas City metro area. The following usage data will be available for baselines and control groups:

- Daily kWh usage data for all customers
- Daily kWh usage data for all customers in the project area prior to AMI
- 15 minute Interval load data for select control group customers outside the project area

The following system level energy production data will be available for analysis:

- Historical and current hourly average and marginal energy production cost data.
- Historical and current hourly system energy production load profile data.
- Historical weather adjusted system energy production load profile data.

Impacts to customer electricity usage and cost for TOU participants will be quantified through the use of a control group:

- Control group will consist of interval and daily load profile data (kWh) for selected customers outside the project area but of similar demographic and geographic vicinity
- Control group load profiles will be captured through the legacy AMR interval metering with increased data reporting

F. Testing Method/Methodology:

The following points provide an overview of how the operational testing for this application will be accomplished:

- 15 minute interval load data will be collected for all TOU participants throughout the project period through KCP&L's AMI system deployed as part of the Project.
- All interval meter data will be stored in KCP&L's MDM System and DMAT.
- At the conclusion of the operational period (through October 2014), TOU participants interval and aggregate usage data will be compared to coincident control group interval and aggregate usage data.

G. Analytical Method/Methodology

The following points provide an overview of the analytical methods that will be used to evaluate the impact and benefits of this application:

- 15-minute interval load data for the control group and TOU participant group will be extracted from KCP&L's DMAT for analysis.
- Load profiles of TOU participants will be compared to those of select control group customers on an hourly, daily, and monthly basis to evaluate the average or typical impact TOU exhibits on measured participant energy usage. Calculated bill impacts will be assessed for statistical significance.
- For each TOU participant, the cost of energy usage billed under the TOU rate will be compared to what the cost of energy use would have been if it had been billed under the standard residential declining block rates.
- Willing TOU participants will be surveyed by a third party to solicit feedback on their experiences managing their energy usage and costs under the TOU rate structure.

2.4.8 Distributed Production of Electricity

Smart grid functions allow utilities to remotely operate DG systems to control output, defer upgrades to generation and T&D assets, and improve voltage regulation. This category includes dispatchable, distributed generation such as combined heat and power, fossil fuel powered backup generators, bio-fuel powered backup generators (e.g., biodiesel, waste to energy, digester gas) or geo-thermal energy. It also includes variable, distributed generation such as solar and wind.

2.4.8.1 DOE SGCT Function to Benefit Rationale

Distributed generation (DG) is located on the distribution system, either on primary distribution feeders or behind the meter. DG supports economic, reliability, and environmental benefits depending on the resource type. Solar photovoltaic panels may support the following benefits:

- Deferred Generation Capacity Investments – DG can be used to reduce the amount of central station generation required during peak times. This should translate into lower infrastructure investments by utilities and cheaper electricity for customers.

- Reduced Ancillary Service Payments – The reserve margin is a required capacity above the peak demand that must be available and is typically +15% of peak demand. If peak demand is reduced, reserve margin would be.
- Reduced Congestion Costs – DG provides energy closer to the end use, so less electricity must be passed through the T&D lines, which reduces congestion.
- Deferred Transmission Capacity Investments – Utilities build transmission with capacity sufficient to serve the maximum amount of load that planning forecasts indicate. The trouble is, this capacity is only required for very short periods each year, when demand peaks. Providing generation capacity closer to the load reduces the power flow on transmission lines, potentially avoiding or deferring capacity upgrades. This may be particularly effective during peak load periods.
- Deferred Distribution Capacity Investments – DG could be used to relieve load on overloaded feeders, potentially extending the time before upgrades are required.
- Reduced Electricity Losses – Since DG is located closer to the load, it displaces grid power. Thus, power flow through distribution circuits and associated peak feeder losses, which are higher than at non-peak times, would be reduce.
- Reduced Electricity Costs – DG could be used to reduce the cost of electricity during times when the price of "grid power" exceeds the cost of producing the electricity with DG. A consumer or the owner of DG realizes savings on his electricity bill.
- Reduced Sustained Outages – The benefit to consumers is based on the value of service (VOS). Distributed generation could be used as a backup power supply for one or more customers until normal electric service could be restored.
- Reduced CO2 Emissions – Renewable energy provides electricity without net CO2 emissions, reducing the emissions produced by fossil-based electricity generators. Furthermore, if DG is used to optimize net load shape to reduce electricity losses then the amount of generation required to serve load will be reduced. Assuming that the generation is fossil-based, emissions will be reduced as well.
- Reduced SOX, NOX, and PM-10 Emissions – Renewable energy provides electricity without net SOX, NOX, and PM-2.5 emissions produced by fossil-based electricity generators providing energy and peak demand. Furthermore, if DG is used to optimize net load shape to reduce electricity losses then the amount of generation required to serve load will be reduced. Assuming that the generation is fossil-based, emissions will be reduced as well.

2.4.8.2 Distributed Rooftop Solar Generation

KCP&L Operational Test Plan
A. Description Approximately 180 kW of distributed solar capacity will be installed within the SGDP area by KCP&L. These systems will likely consist of one large commercial-scale system to be installed on a local school rooftop and various smaller distributed systems on homes and businesses throughout the project area. All solar systems are currently planned to be utility owned, installed on leased rooftops, and connected on the utility side of the meter.

B. Expected Results

This technical demonstration is expected to yield the following:

- Determination of the percent of nameplate that solar generation systems in Kansas City could be expected to produce, and verification of the annual kWh solar production estimates produced by the NREL PVWatts Calculator.
- Development of a per unit solar generation load curve that can be used to assess the impact of solar generation on customer, circuit, and system level analysis.
- Determine the coincidence of solar generation with system annual peak, expressed as a percentage solar generation nameplate rating.
- Determine the go forward viability of a leased rooftop business model for utility owned distributed solar generation.

C. Relevant Impact Metrics

The Technical Demonstration of this application will not contribute to any Impact Metrics.

D. Benefits Analysis Method/Factors

The DOE SGCT will be used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits will be quantified.

- Deferred Generation Capacity Investments
- Reduced Electricity Costs
- Reduced CO_2 Emissions

Benefits will be calculated using SGCT formulas. The following factors will be measured, projected or calculated during the application operation and/or demonstration.

Deferred Generation Capacity Investments

- Distributed Generation Use at Annual Peak Time (MW)

Reduced Electricity Costs (Utility)

- Annual Distributed Generation Production (MWh)

Reduced CO_2 Emissions

- Annual Distributed Generation Production (MWh)

E. Baseline Data & Control Groups

AMI metering that is deployed for all customers, circuits, and distributed energy resources within the SGDP area. The following usage data will be available for baselines:

- 15 minute interval load data of all customers.
- Average hourly interval load data by customer class.
- 15 minute interval total load data for circuit.
- 15 minute interval delivered and received load data for each Solar DG site.

The following system level energy production data will be available for analysis:

- Historical and current hourly average and marginal energy production cost data.
- Historical and current hourly system energy production load profile data.
- Historical weather adjusted system energy production load profile data.

F. Testing Method/Methodology

The following points provide an overview of how the operational testing for this application will be accomplished:

- Solar generation production data at each site will be measured through the AMI system deployed as part of the Project. All data collected will be stored in KCP&L's MDM System.
- The solar generation systems will be metered to measure energy received from and delivered to the grid to provide the net efficiency of the solar generation system. The load profile of energy delivered and received for each Solar Generation unit will be collected and available.

G. Analytical Method/Methodology

The following points provide an overview of the analytical methods that will be used to evaluate the impact and benefits of this application:

- AMI interval load data for each solar generation customers within the Project area will be extracted from the MDM System through KCP&L's DMAT.
- The DMAT has built in functionality that will enable the aggregation and calculation of the following hourly load profiles.
  - Net Energy Solar Production from each Solar Generation site
  - Total Net Energy Solar Production for all Solar Generation sites.
  - Average Net Energy Solar Production per kW of Solar Generation Nameplate Capacity.
- Distributed Generation Use at Annual Peak Time (MW) will be determined by selecting the Total Net Energy Solar Production value at the System Annual Peak Hour.
- Annual Reduced Utility Electricity Cost analysis will performed by summing the hourly savings that are calculated from the hourly Total Net Energy Solar Production load profile data and the hourly average and marginal energy production cost data.

2.4.9 Storing Electricity for Later Use

Remote Control of electricity storage (ES) inflow/outflow reduces energy costs and enhances power generation and transmission and distribution capacity utilization.

2.4.9.1 DOE SGCT Function to Benefit Rationale

Electricity can be stored as chemical or mechanical energy and used later by consumers, utilities or grid operators. In distributed applications, energy storage technologies most likely utilize inverter-based electrical interfaces that can produce real and reactive power. Depending on the capacity and stored energy of these devices, they can provide the following economic, reliability, and environmental benefits.

- Optimized Generator Operation – The ability to respond to changes in load would enable grid operators to dispatch a more efficient mix of generation that could be optimized to reduce cost, including the cost associated with polluting emissions. Electricity storage can be used to absorb generator output as electrical load decreases, allowing the generators to remain in their optimum operating zone. The stored electricity could then be used later so that dispatching additional, less efficient generation could be avoided. The storage can have the effect of smoothing the load curve that the generation fleet must meet. This benefit includes two components: (1) avoided generator start-up costs and (2) improved performance due to improved heat rate efficiency and load shaving.

- Deferred Generation Capacity Investments – Electricity storage can be used to reduce the amount of central station generation required during peak times. This would tend to improve the overall load profile and allow a more efficient mix of generation resources to be dispatched. This can save utilities money on their generation costs.
- Reduced Ancillary Services Cost – Ancillary services including spinning reserve and frequency regulation can be provided by energy storage resources. The reserve margin is a required capacity above the peak demand that must be available and is typically +15% of peak demand. If peak demand is reduced, reserve margin would be reduced.
- Reduced Congestion Cost – Distributed energy resources provide energy closer to the end use, so less electricity must be passed through the T&D lines, which reduces congestion.
- Deferred Transmission Capacity Investments – Utilities build transmission with capacity sufficient to serve the maximum amount of load that planning forecasts indicate. The trouble is, this capacity is only required for very short periods each year, when demand peaks. Providing stored energy capacity closer to the load reduces the power flow on transmission lines, potentially avoiding or deferring capacity upgrades. This may be particularly effective during peak load periods.
- Deferred Distribution Capacity Investments – Electricity storage can also be used to relieve load on overloaded stations and feeders, potentially extending the time before upgrades or additions are required.
- Reduced Electricity Losses – By managing peak feeder loads with electricity storage, peak feeder losses, which are higher than at non-peak times, would be reduced.
- Reduced Electricity Costs – Electricity storage can be used to reduce the cost of electricity, particularly during times when the price of “grid power” is very high. A consumer or the owner of an enabled DER realizes savings on his electricity bill.
- Reduced Sustained Outages – Electricity storage can be used as a backup power supply for one or more customers until normal electric service can be restored. However, the backup would only be possible for a limited time (a few hours) depending on the amount of energy stored.
- Reduced Momentary Outages – When combined with the necessary control system, energy storage could act like an uninterruptible power supply (UPS), supporting end use load during a momentary outage.
- Reduced Sags and Swells – The same UPS capability could be used to enable load to ride through voltage sags and swells.
- Reduced CO_2 Emissions – Electricity storage can reduce electricity peak demand. This translates into a reduction in CO_2 emissions produced by fossil-based electricity generators. However, since electricity storage has an inherent inefficiency associated with it, electricity storage could increase overall CO_2 emissions if fossil fuel generators are used for charging.
- Reduced SO_X, NO_X, and PM-10 Emissions – Electricity storage can reduce electricity peak demand. This translates into a reduction in polluting emissions produced by fossil-based electricity generators. However, since electricity storage has an inherent inefficiency associated with it, electricity storage could increase overall emissions if fossil fuel generators are used for charging.
- Reduced Oil Usage – If plug-in electric vehicles are utilized as grid storage assets, they can also provide the additional benefit of reduced oil usage. PEVs increase the fuel efficiency of vehicles by using electric energy stored in their batteries to power the vehicle as opposed to using oil based fuel. This fuel efficiency gain translates into a reduction in oil consumption per mile traveled.

2.4.9.2 Electric Energy Time Shift

The Electric Energy Time-Shift application involves storing electricity when the price of electricity is low and discharging that electricity when the price of electricity is high. The energy that is discharged from the energy storage could be sold via the wholesale market, sold under terms of a power purchase agreement, or used by an integrated utility to reduce the overall cost of providing generation during peak times.

KCP&L Operational Test Plan

A. Description

A 1.0 MWh, 1.0 MW-capable grid-connected Battery Energy Storage System will be installed at the Midtown Substation with direct interconnect to a single 13.2 kV circuit, immediately downstream of the substation transformer. A daily charge/discharge cycle will be implemented to demonstrate and evaluate the operational benefit of using the battery for electric energy time shift applications.

B. Expected Results

The operational demonstration of the grid connected battery in this application is expected to yield the following:

- The system is expected to operate at greater than 70% efficient with respect to net energy output versus input.
- Utility electric production costs will be reduced by charging the battery with low cost Off-Peak energy and discharging it at higher cost production times.

C. Relevant Impact Metrics

Storage	Annual Storage Dispatch (kWh)
Storage	Average Energy Storage Efficiency (%)

The Operational Testing of this application will contribute to these Impact Metrics.

At each reporting milestone, operational test, or demonstration period, data will be compared to baseline data to determine a quantified impact. Quantified impacts measured will be reported in semi-annual impact metric reports.

D. Benefits Analysis Method/Factors

The DOE SGCT will be used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits will be quantified.

- Optimized Generation Operation

Benefits will be calculated using SGCT formulas. The following factors will be measured, projected or calculated during the application operation and/or demonstration.

Optimized Generation Operation

- Reduced Annual Generation Cost ($)

Additionally, the DOE Energy Storage Computational Tool (ESCT) will be used to perform the benefit analysis for a utility owned GES system. The following Stationary Energy Storage applications will be combined in this analysis.

- Primary Application – Electric Energy Time Shift
- Secondary Application – Electric Supply Capacity
- Secondary Application – T&D Upgrade Deferral

Primary Benefit: Reduced Electricity Costs (Utility/Ratepayer)

- Calculation: Total Energy Discharged for Energy Time-Shift (MWh) x [Avg. Variable Peak Generation Cost ($/MWh) - Avg. Variable Off-Peak Generation Cost ($/MWh) /ES Efficiency (%)]

E. Baseline Data & Control Groups

AMI metering that is deployed for all customers, circuits, and distributed energy resources within the SGDP area. The following usage data will be available for baselines:

- 15 minute interval total load data for the battery circuit.
- 15 minute interval delivered and received load data for the grid battery.

The following system level energy production data will be available for analysis.

- Historical and current hourly average and marginal energy production cost data.
- Historical and current hourly system energy production load profile data.
- Historical weather adjusted system energy production load profile data.

F. Testing Method/Methodology:

The following points provide an overview of how the operational testing for this application will be accomplished:

- Energy delivered and received to the BESS will be measured on the high side of the BESS interconnection transformer through the AMI system deployed as part of the Project. All data collected will be stored in KCP&L's MDM System.
- Weekly daily charge/discharge cycle will be implemented to demonstrate and evaluate the operational benefit of using the battery for electric energy time shift applications. Charging will occur daily from 1-6 AM and discharge will occur from 3-7 PM
- Individual seasonal testing and data collection periods will be conducted to evaluate the potential impact of seasonal parasitic loads on overall BESS efficiency.

G. Analytical Method/Methodology

The following points provide an overview of the analytical methods that will be used to evaluate the impact and benefits of this application::

- AMI interval load data for the BESS will be extracted from the MDM System through KCP&L's DMAT.
- The DMAT has built in functionality that will enable and calculation of the following hourly load profiles.
    - BESS Energy Discharged to grid.
    - BESS Energy Received from grid.
- An annual hourly charge/discharge load profile for the BESS will be constructed using the DMAT load profile data created for the application operational testing periods,
- The Annual BESS Efficiency will be calculated as (Annual BESS Energy Delivered)/(Annual BESS Energy Received)
- Annual Reduced Utility Electricity Cost will be calculated as Σ[(hourly BESS Energy Discharged) X (hourly average/marginal energy production cost)] - Σ[(hourly BESS Energy Received) X (hourly average/marginal energy production cost)]

2.4.9.3 Electric Supply Capacity

As demand on the electricity grid grows from year-to-year, the need to install additional generation capacity to meet this demand also grows. The Electric Supply Capacity application involves using energy storage to defer and/or to reduce the need to invest in new generation capacity. In a regulated market, a utility may install a marginal amount of energy storage to meet capacity needs thus deferring the need to invest in a larger conventional generation solution. In a deregulated market, where the electric supply capacity market is evolving, this application could involve selling energy storage capacity to the market in order to generate a capacity credit revenue stream for a non-utility merchant. However, this market is evolving and in some markets, generation capacity cost is included in wholesale energy prices.

KCP&L Operational Test Plan

A. Description

A 1.0 MWh, 1.0 MW-capable grid-connected Battery Energy Storage System will be installed at the Midtown Substation with direct interconnect to a single 13.2 kV circuit, immediately downstream of the substation transformer. DMS based battery control functions will be implemented to discharge the battery during time of peak generation requirements including:

- Block Discharge Mode for operator defined fixed discharge, and
- DERM mode for discharge in response to DR events.

B. Expected Results

The operational demonstration of the grid connected battery in this application is expected to yield the following:

- Demonstration controlled operation of battery at time of system peak via operator initiated events and DERM initiated DR events.
- Determination of the effective MW peak reduction for a 1MWh battery.

C. Relevant Impact Metrics

The Operational Testing of this application will contribute to these Impact Metrics.

Storage	Annual Storage Dispatch (kWh)
Storage	Average Energy Storage Efficiency (%)

At each reporting milestone, operational test, or demonstration period, data will be compared to baseline data to determine a quantified impact. Quantified impacts measured will be reported in semi-annual impact metric reports.

D. Benefits Analysis Method/Factors

The DOE SGCT will be used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits will be quantified.

- Deferred Generation Capacity Investments

Benefits will be calculated using SGCT formulas. The following factors will be measured, projected or calculated during the application operation and/or demonstration.

Deferred Generation Capacity Investments

- Energy Storage Use at Annual Peak Time (MW)

Additionally, the DOE ESCT will be used to perform the benefit analysis for a utility owned GES system. The following Stationary Energy Storage applications that will be combined in this analysis.

- Primary Application – Electric Energy Time Shift
- Secondary Application – Electric Supply Capacity
- Secondary Application – T&D Upgrade Deferral

Primary Benefit: Deferred Generation Capacity Investment (Utility/Ratepayer)

- Calculation: [Generation Capacity Deferred (MW) x Capital Cost of Deferred Generation Capacity ($/MW) x Fixed Charge Rate] + [Yearly Fixed O&M Costs of Deferred Generation Capacity ($/MW-yr) x Generation Capacity Deferred (MW)]

E. Baseline Data & Control Groups

AMI metering that is deployed for all customers, circuits, and distributed energy resources within the SGDP area. The following usage data will be available for baselines:

- 15 minute interval total load data for the battery circuit.
- 15 minute interval delivered and received load data for the grid battery.

The following system level energy production data will be available for analysis.

- Historical and current hourly average and marginal energy production cost data.
- Historical and current hourly system energy production load profile data.
- Historical weather adjusted system energy production load profile data.

F. Testing Method/Methodology:

The following points provide an overview of how the operational testing for this application will be accomplished:

- Energy delivered and received to the BESS will be measured on the high side of the BESS interconnection transformer through the AMI system deployed as part of the Project. All data collected will be stored in KCP&L's MDM System.
- BESS discharge for electricity supply capacity will be initiated in two ways; 1) the distribution grid operator can manually initiate a scheduled Block Mode discharge, or 2) the DERM can schedule a DR event for the BESS.
- Multiple discharge events will be conducted to evaluate the potential maximum discharge levels that can be sustained for 1, 2, 3, & 4 hour discharge events.

G. Analytical Method/Methodology

The following points provide an overview of the analytical methods that will be used to evaluate the impact and benefits of this application:

- AMI interval load data for each BESS discharge for this application will be extracted from the MDM System through KCP&L's DMAT.
- Multiple discharge events will be analyzed to the potential maximum discharge levels that can be sustained for 1, 2, 3, & 4 hour discharge events.
- Historical hourly system energy production load profile data will be analyzed to determine the optimum block discharge level and duration to maximize the BESS impact on capacity reduction.
- Due to other project operational testing requirements, it may not be possible to initiate a battery discharge event at system peak, but the project team will determine what the impact would be if the BESS were normally available.

2.4.9.4 T&D Upgrade Deferral

Transmission and Distribution (T&D) Upgrade Deferral application involves installing energy storage in order to delay transmission and/or distribution system upgrades. The value of this application is derived from the fact that storage can be used to provide enough incremental capacity to defer the need for a large lump investment in T&D equipment. If using an energy storage device to defer a T&D investment, proper consideration must be given to reliability. T&D capital investments must maintain the extremely high reliability of the electric delivery system. Therefore, any energy storage solution that defers the need for a T&D investment must similarly maintain the reliability of the system. For energy storage deployments this means ensuring that the storage solution has enough redundancy or modularity such that the effective reliability of the solution is adequate.

KCP&L Operational Test Plan

A. Description

A 1.0 MWh, 1.0 MW-capable grid-connected Battery Energy Storage System will be installed at the Midtown Substation with direct interconnect to a single 13.2 kV circuit, immediately downstream of the substation transformer. DMS based control functions will be used to implement load-following discharge of the battery to demonstrate and evaluate the operational benefit of using the battery for electric T&D Upgrade Deferral applications. The operator will be able to select from the following grid level targets for the load-following function:

- Station Power Transformer
- Distribution Substation Bus
- Distribution Circuit

B. Expected Results

The operational demonstration of the grid connected battery in this application is expected to yield the following:

- Demonstrate load following discharge of battery based on real-time transformer, bus, and circuit loadings.
- Using several representative company distribution circuit load profiles, determination a representative distribution circuit peak reduction (kW) that can be achieved for a 1MWh battery.

C. Relevant Impact Metrics

The Operational Testing of this application will contribute to these Impact Metrics.

Storage	Annual Storage Dispatch (kWh)
Storage	Average Energy Storage Efficiency (%)

At each reporting milestone, operational test, or demonstration period, data will be compared to baseline data to determine a quantified impact. Quantified impacts measured will be reported in semi-annual impact metric reports.

D. Benefits Analysis Method/Factors

The DOE SGCT will be used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits will be quantified.

- Deferred Distribution Capacity Investments

Benefits will be calculated using SGCT formulas. The following factors will be measured, projected or calculated during the application operation and/or demonstration.

Deferred Distribution Capacity Investments

- Distribution Feeder Load Reduction (MW)

Additionally, the DOE ESCT will be used to perform the benefit analysis for a utility owned GES system. The following Stationary Energy Storage applications that will be combined in this analysis.

- Primary Application – Electric Energy Time Shift
- Secondary Application – Electric Supply Capacity
- Secondary Application – T&D Upgrade Deferral

Primary Benefit: Deferred Distribution Investments (Utility/Ratepayers)

- This yearly deferral amount only accrues between the initial and final year of distribution deferral.
- [Distribution Capacity Deferred (kVA) x Capital Cost of Deferred Distribution Capacity ($/kVA) x Fixed Charge Rate] + Yearly O&M Costs of Deferred Dist. Capacity ($/yr)

E. Baseline Data & Control Groups

AMI metering that is deployed for all customers, circuits, and distributed energy resources within the SGDP area. The following usage data will be available for baselines:

- 15 minute interval total load data for each SGDP circuit.
- 15 minute interval delivered and received load data for the grid battery.

The following system level energy production data will be available for analysis.

- Historical and current hourly average and marginal energy production cost data.
- Historical and current hourly system energy production load profile data.
- Historical weather adjusted system energy production load profile data.

The following historical data is available from KCP&L's EMS.

- Historical substation hourly load profile data.
- Historical distribution circuit hourly load profile data.

F. Testing Method/Methodology:

The following points provide an overview of how the operational testing for this application will be accomplished:

- Energy delivered and received to the BESS will be measured on the high side of the BESS interconnection transformer through the AMI system deployed as part of the Project. All data collected will be stored in KCP&L's MDM System.
- BESS discharge for T&D Upgrade Deferral will be initiated in by the distribution grid operator can manually setting BESS to Load Following Mode in the DMS. The operator will select the load point (station transformer, bus, or circuit) on the grid to follow and the max load level to maintain.
- Multiple load following discharge events will be conducted to evaluate the potential distribution load reduction that can be achieved under various heavy load conditions.

G. Analytical Method/Methodology

The following points provide an overview of the analytical methods that will be used to evaluate the impact and benefits of this application:

- AMI interval load data for each BESS discharge for this application will be extracted from the MDM System through KCP&L's DMAT
- Multiple load following discharge events will be analyzed to evaluate the potential distribution load reduction that can be achieved under various loading conditions.
- Historical load profiles for other KCP&L substations and circuits that are substantially different from the SmartGrid Demonstration Circuits which will be analyzed to identify typical load profiles for which the BESS would have the greatest potential to defer distribution upgrades.
- The level of discharge for T&D Upgrade deferral that is coincident with annual system peak will be determined.

2.4.9.5 Time-of-Use Energy Cost Management

For the Time-of-use (TOU) Energy Cost Management application, energy end users (utility customers) would use energy storage devices to reduce their overall costs for electricity. They would accomplish this by charging the storage during Off-Peak periods when the electric energy price is low, then discharge the energy during times when On-Peak TOU energy prices apply. This application is similar to Electric Energy Time-shift application, although electric energy savings are based on the customer's retail tariff, whereas the benefit for Electric Energy Time-shift is based on the prevailing wholesale price.

KCP&L Technology Demonstration Plan

A. Description

A consumer Premise Energy Storage System will be installed at the SmartGrid Demonstration House in conjunction with the 3.1 kW solar PV array. The will consist of an 11.7 kWh lithium-ion battery with a unique hybrid inverter/converter rated for 6 kW discharge.

The premise energy storage system will be configured to demonstrate how the consumer can use the PESS in conjunction with multitiered TOU rates to reduce their overall cost for electricity. This will be accomplished by charging the storage during Off-Peak periods when the electric energy price is low or during time of excess solar PV production, then discharging the energy during times when On-Peak TOU energy prices apply.

B. Expected Results

This technical demonstration is expected to yield the following:

- Typical daily charge/discharge load cycles will be developed and demonstrated at the Demonstration House.
- The Round Trip Efficiency of the Storage System factor for the PESS will be determined. The system is expected to operate at greater than 70% efficient with respect to net energy output versus input.
- The Total Energy Discharged for TOU Energy factor for the PESS will be determined. The system is expected to have approximately 10 kWh available daily for TOU discharge.
- The charge/discharge load cycles developed will be mathematically applied to several "typical" load profiles to illustrate how a PESS system can be used with TOU rates to lower the customers energy cost.

C. Relevant Impact Metrics

The Technical Demonstration of this application will not contribute to any Impact Metrics.

D. Benefits Analysis Method/Factors

The DOE SGCT will be used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits will be quantified.

- Deferred Generation Capacity Investments
- Deferred Distribution Capacity Investments
- Reduced Electricity Costs

Benefits will be calculated using SGCT formulas. The following factors will be measured, projected or calculated during the application operation and/or demonstration.

Deferred Generation Capacity Investments (Utility)

- Energy Storage Use at Annual Peak Time (MW)

Deferred Distribution Capacity Investments (Utility)

- Distribution Feeder Load Reduction (MW)
- Capital Carrying Charge of Distribution Upgrade ($/MW)

Reduced Electricity Costs (Customer)

- Reduced Total Annual Electric Consumption (kWh) by customer class.

Additionally, the DOE ESCT will be used to perform the benefit analysis for a customer owned PESS system. The following Stationary Energy Storage applications that will be combined in this analysis.

- Primary Application – Time-of-Use Energy Cost Management
- Secondary Application – Renewable Energy Time Shift
- Secondary Application – Electric Service Reliability

Primary Benefit for TOU Energy Cost Management:

- Reduced Electricity Cost (Consumer)

Secondary Benefit:

- Deferred Generation Capacity Investment (Utility)

E. Baseline Data & Control Groups

AMI metering that is deployed for all customers, circuits, and distributed energy resources within the SGDP area. The following usage data will be available for baselines::

- 15 minute interval load data of all customers.
- Average hourly interval load data by customer class.
- 15 minute interval delivered and received load data for each Solar DG site.

F. Testing Method/Methodology:

The following points provide an overview of how the operational testing for this application will be accomplished:

- Energy delivered and received to the PESS will be measured by the PESS management system.
- A daily charge/discharge cycle will be implemented to demonstrate and evaluate the benefit of using the battery for electric energy time shift in conjunction with TOU rates.

- Charging will occur daily from 1-5 AM and discharge will occur from 3-7 PM
- The PESS will be operated in this mode for a minimum of two weeks to determine the Round Trip Efficiency of the Storage System factor.

G. Analytical Method/Methodology

The following points provide an overview of the analytical methods that will be used to evaluate the impact and benefits of this application:

- Energy delivered and received to the PESS measured by the PESS management system will be exported to Excel for analysis.
- The Round Trip Efficiency of the Storage System factor will be calculated as (PESS Energy Delivered)/(PESS Energy Received).
- The Reduced Electricity Cost for the consumer will be calculated using the ESCT formula.

2.4.9.6 Renewable Energy Time Shift

The Renewables Energy Time-shift application involves storing electricity from renewable sources when the price of electricity is low and using (or selling) that stored energy when the price of electricity is higher. Because solar typically produces its maximum energy midday when electricity prices are typically lower, the price differential between the electricity used to charge the battery and the electricity sold at peak can be significant. The energy that is discharged from the storage could be sold via the wholesale market, sold under terms of an energy purchase contract, or used by an integrated utility to reduce the overall cost of providing generation during peak times.

KCP&L Technology Demonstration Plan

A. Description

A consumer Premise Energy Storage System will be installed at the SmartGrid Demonstration House in conjunction with the 3.1 kW solar PV array. The PESS will consist of an 11.7 kWh lithium-ion battery with a unique hybrid inverter/converter rated for 6 kW discharge. The PESS will be configured to store solar electric energy generated during peak generation times (6 AM – 4 PM) and then discharge the stored energy during times of peak usage and rates (typically 4 – 8 PM).

B. Expected Results

This technical demonstration is expected to yield the following:

- Typical daily charge/discharge load cycles for renewable time shift will be developed and demonstrated at the Demonstration House.
- The DC-DC Efficiency factor of the PESS for Renewable Time Shift will be determined. The system is expected to operate at greater than 90% efficient with respect to stored DC energy output versus solar DC energy input.
- The Energy Discharged for Renewable Energy Time-Shift factor for the PESS will be determined. The system is expected to have approximately 10 kWh available daily for discharge.
- The charge/discharge load cycles developed will be mathematically applied to several “typical” load profiles to illustrate how a PESS system can be used with TOU rates to lower the customer’s energy cost.

C. Relevant Impact Metrics

The Technical Demonstration of this application will not contribute to any Impact Metrics.

D. Benefits Analysis Method/Factors

The DOE SGCT will be used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits will be quantified.

- Deferred Generation Capacity Investments
- Reduced Electricity Costs
- Reduced CO_2 Emissions

Benefits will be calculated using SGCT formulas. The following factors will be measured, projected or calculated during the application operation and/or demonstration.

Deferred Generation Capacity Investments

- Distributed Generation Use at Annual Peak Time (MW)

Reduced Electricity Costs (Utility)

- Reduced Total Annual Electric Consumption (kWh) by customer class.

Reduced CO_2 Emissions

- Annual Distributed Generation Production (MWh)

Additionally, the DOE ESCT will be used to perform the benefit analysis for a customer owned PESS system. The following Stationary Energy Storage applications that will be combined in this analysis.

- Primary Application – Time-of-Use Energy Cost Management
- Secondary Application – Renewable Energy Time Shift
- Secondary Application – Electric Service Reliability

Primary Benefit for Renewable Energy Time Shift:

- Reduced Electricity Costs (Consumer)

E. Baseline Data & Control Groups

AMI metering that is deployed for all customers, circuits, and distributed energy resources within the SGDP area. The following usage data will be available for baselines:

- 15 minute interval load data of all customers.
- 15 minute interval delivered and received load data for each Solar DG site.

F. T Method/Methodology:

The following points provide an overview of how the technical demonstration of this application will be accomplished:

- A customer solar electric generation system will be installed and connected to the PESS.
- Energy generated by the customer's solar electric generation system will be measured by the PESS management system.
- A daily charge/discharge program will be implemented to demonstrate and evaluate the benefit of using the PESS for solar generation time shift in conjunction with TOU rates. Charging will occur daily during Off-Peak rate times from available solar generation and discharge during On-Peak rate times from 3-7 PM
- The PESS will be operated with this as its standard mode during multiple seasons.

G. Analytical Method/Methodology

The following points provide an overview of the analytical methods that will be used to evaluate the impact and benefits of this application:

- Energy delivered to the PESS by the solar generation system will be measured by the PESS management system and will be exported to Excel for analysis.
- Energy delivered and received by the PESS storage system will be measured by the PESS management system and will be exported to Excel for analysis.
- The customer's Reduced Electricity Cost will be calculated using the ESCT formulas.

2.4.9.7 Electric Service Reliability

The Electric Service Reliability application involves using electric energy storage to ensure highly reliable electric service. In the event of a complete power outage lasting more than a few seconds, the energy storage system provides enough energy to ride through outages of extended duration; complete an orderly shutdown of processes; and/or transition to on-site generation resources.

KCP&L Technology Demonstration Plan

A. Description

A consumer Premise Energy Storage System will be installed at the SmartGrid Demonstration House in conjunction with the 3.1 kW solar PV array. The PESS will consist of a 11.7 kWh lithium-ion battery with a unique hybrid inverter/converter rated for 6kW discharge. The PESS will be configured to provide emergency stand-by power to critical loads during extended power outages.

B. Expected Results

This technical demonstration is expected to yield the following:

- Emergency stand-by power functionality will be demonstrated at the Demonstration House.
- Develop an understanding of how much critical load the PESS can maintain indefinitely at the Demonstration House with the installed solar panels.

C. Relevant Impact Metrics

The Technical Demonstration of this application will not contribute to any Impact Metrics.

D. Benefits Analysis Method/Factors

The DOE SGCT will be used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits will be quantified.

- Reduce Sustained Outages

Benefits will be calculated using SGCT formulas. The following factors will be measured, projected or calculated during the application operation and/or demonstration.

Reduce Sustained Outages

- SAIDI (base & projected)

Additionally, the DOE ESCT will be used to perform a benefit analysis for a customer owned PESS system. The following Stationary Energy Storage applications that will be combined in this analysis.

- Primary Application – Time-of-Use Energy Cost Management
- Secondary Application – Renewable Energy Time Shift
- Secondary Application - Electric Service Reliability

Primary Benefit for Electric Service Reliability:

- Reduced Outages (Consumer)

E. Baseline Data & Control Groups

The following historical system level reliability statistics will be available for analysis:

- System Average Interruption Frequency Index (SAIFI)
- System Average Interruption Duration Index (SAIDI)
- Customer Average Interruption Duration Index (CAIDI)

F. Testing Method/Methodology:

The following points provide an overview of how the operational testing for this application will be accomplished:

- A customer critical load panel will be installed and connected to the PESS.
- Load served by the customer critical load panel will be measured by the PESS management system.
- Customer's main breaker will be opened simulating a power outage and the PESS will use its internal battery storage to maintain service to the critical loads panel.
- The PESS will be operated in this mode until the battery is discharged to determine the length of time the critical loads can be sustained from the battery storage alone.

G. Analytical Method/Methodology

The following points provide an overview of the analytical methods that will be used to evaluate the impact and benefits of this application:

- Energy delivered to the customer critical load panel will be measured by the PESS management system and will be exported to Excel for analysis.
- The length of time the PESS can sustain power to the customer critical load panel will be measured by the PESS management system.
- The Reduced Outage Benefit to the consumer will be calculated using the ESCT formula.

2.4.9.8 PEV Charging

The batteries in plug-in electric vehicles (PEVs) can be portrayed as non-stationary energy storage devices. As such, they are similar to stationary energy storage devices and support economic, reliability and environmental benefits. By increasing vehicle fuel efficiency, they also support Reduced Oil Usage, an Energy Security Benefit.

KCP&L Technology Demonstration Plan
A. Description The ChargePoint VCMS and a total of ten Electric Vehicle Charging Stations (EVCSs) will be deployed within the SGDP area. Each EVCS consists of a dual port, level 2 (240V) Coulomb Charging Station capable of charging two PEVs simultaneously. The EVCSs will be installed on the EVCS sponsor's side of the meter and the charging will be free to the public. The VCMS will be integrated with the DERM and will serve as the "control authority" for each EVCS during demand response events.
B. Expected Results This technical demonstration is expected to yield the following: • Technical demonstration of 10 public accessible PEV charging stations providing PEV owners the convenience of public charging. • The DERM will dispatch DR events to the EVCS demonstrating how PEVs can participate in DR events. • KCP&L will be able to monitor, record, and summarize the charging patterns at each of the EVCS sites.
C. Relevant Impact Metrics The Technical Demonstration of this application will not contribute to any Impact Metrics.
D. Benefits Analysis Method/Factors The DOE SGCT will be used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits will be quantified. • Reduced CO_2 Emissions Benefits will be calculated using SGCT formulas. The following factors will be measured, projected or calculated during the application operation and/or demonstration. Reduced CO_2 Emissions • Annual Electricity Consumed by PEVs (kWh)
E. Baseline Data & Control Groups The Technical Demonstration of this application does not require any Baseline Data or the establishment of any Control Groups.
F. Testing Method/Methodology: The following points provide an overview of how the operational testing for this application will be accomplished: • Energy use at each PEV charging station will be measured through PEV Charge Management System and the AMI system deployed as part of the Project. All data collected by the AMI system will be stored in KCP&L's Meter Data Management system.
G. Analytical Method/Methodology The Technical Demonstration of this application does not require any analytical calculations.

2.5 Data Collection and Benefits Analysis

A key objective in KCP&L's SGDP will be to quantify the costs and benefits of each of the solutions separately and as a complete solution. The Demonstration is designed as a regionally unique effort to display the benefits of single initiatives and the overall synergies and interrelations that can occur as a result of building complete programs. In KCP&L's budgeting process, the operating and capital costs of each of the SmartGrid Demonstration subprojects are defined along with the potential benefits. These benefits include operational, economic, customer and environmental improvements.

The operational demonstration and testing plans, outlined in the previous section, have been developed to not only demonstrate the SmartGrid Functions achievable through end-to-end interoperability, but to also capture and quantify the operational benefits achieved by each of the SmartGrid applications. EPRI and the DOE have developed specific, quantifiable methodologies to translate benefit metrics into potential monetary value. KCP&L will use the DOE-developed metrics reporting and computational tools to evaluate the overall costs and benefits of the demonstrated SmartGrid technologies and functions.

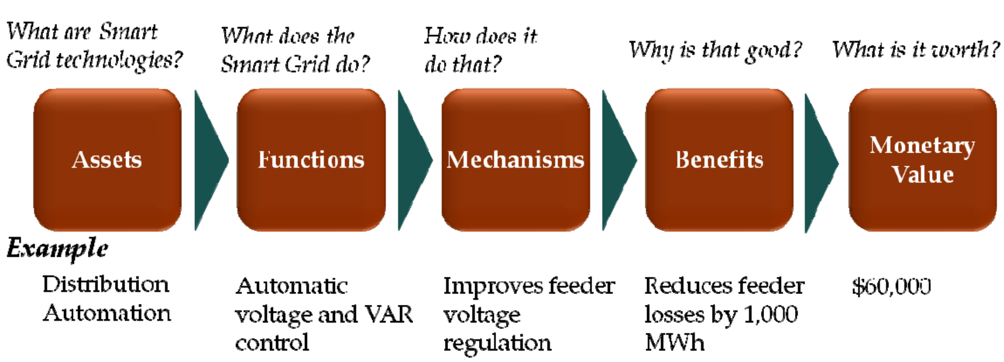
Additionally, where possible, KCP&L will quantify the cost effectiveness of the technology solutions developed for the demonstration vs. existing KCP&L grid automation technologies and solutions to determine the cost effectiveness of the demonstration technologies on a go-forward basis at KCP&L.

2.5.1 SmartGrid Computational Tool Analysis [22]

The DOE has developed a standard methodology and tool for evaluating the performance, costs, and benefits of all Smart Grid field projects including the SGIG and SGDG programs. In developing this methodology, the DOE defined a standardized set of smart grid assets, functions, and benefits along with guidelines for calculating associated benefits. This methodology and tool allows the costs and benefits of all smart grid projects to be evaluated consistently.

The KCP&L Demonstration will use the DOE-developed Smart Grid Computational Tool (SGCT) to evaluate the overall costs and benefits in order to estimate the project's overall value. The SGCT allows the user to identify the assets to be deployed and functions to be demonstrated by the SGDP and to calculate the costs and benefits in order to estimate the project's overall value. Figure 2-91 illustrates how the SGCT translates Smart Grid Assets into Monetary Value.

Figure 2-91: SGCT Translation of Smart Grid Assets to Monetary Value



Using the SGCT, the SGDP team: 1) identified the Smart Grid Assets deployed; 2) identified the Smart Grid Functions that the Demonstration would enable; and 3) for each Function, identified the applicable benefit mechanisms. Based on these inputs, the SGCT identified the expected benefits the project could achieve. Table 2-21 identifies the potential SGDP benefits by Smart Grid Function.

Table 2-21: SGCT Function-Benefit Chart for KCP&L SmartGrid Demonstration Project

Benefits			Smart Grid Functions								
			Delivery						Use	Other	
			Automated Feeder and Line Switching	Automated Islanding and Reconnection	Automated Voltage and VAR Control	Diagnosis & Notification of Equipment Condition	Real-Time Load Measurement & Management	Real-time Load Transfer	Customer Electricity Use Optimization	Storing Electricity for Later Use	Distributed Production of Electricity
Economic	Improved Asset Utilization	Optimized Generator Operation									
		Deferred Generation Capacity Investments							YES	YES	YES
		Reduced Ancillary Service Cost									
		Reduced Congestion Cost									
	T&D Capital Savings	Deferred Transmission Capacity Investments									
		Deferred Distribution Capacity Investments					YES	YES	YES	YES	YES
		Reduced Equipment Failures				YES					
	T&D O&M Savings	Reduced T&D Equipment Maintenance Cost									
		Reduced T&D Operations Cost	YES								
		Reduced Meter Reading Cost					YES				
	Theft Reduction	Reduced Electricity Theft					YES				
	Energy Efficiency	Reduced Electricity Losses			YES		YES	YES	YES	YES	YES
	Electricity Cost Savings	Reduced Electricity Cost							YES	YES	YES
Reliability	Power Interruptions	Reduced Sustained Outages	YES	YES		YES	YES			YES	YES
		Reduced Major Outages		YES			YES	YES			
		Reduced Restoration Cost	YES			YES	YES				
	Power Quality	Reduced Momentary Outages									
		Reduced Sags and Swells									
Environmental	Air Emissions	Reduced CO2 Emissions	YES		YES		YES	YES	YES	YES	YES
		Reduced SOx, NOx, and PM-2.5 Emissions	YES		YES		YES	YES	YES	YES	YES
Security	Energy Security	Reduced Oil Usage (not monetized)	YES				YES			YES	
		Reduced Wide-scale Blackouts									

The SGCT uses two different types of data to calculate benefits, baseline data and project data. Baseline data are intended to reflect what the state of the grid would have been during the project period assuming a "no-build" scenario. Project data reflect the actual state of the grid as the smart grid technology is implemented. All benefit assumptions rely on the calculated difference between baseline and project data at a given point in time.

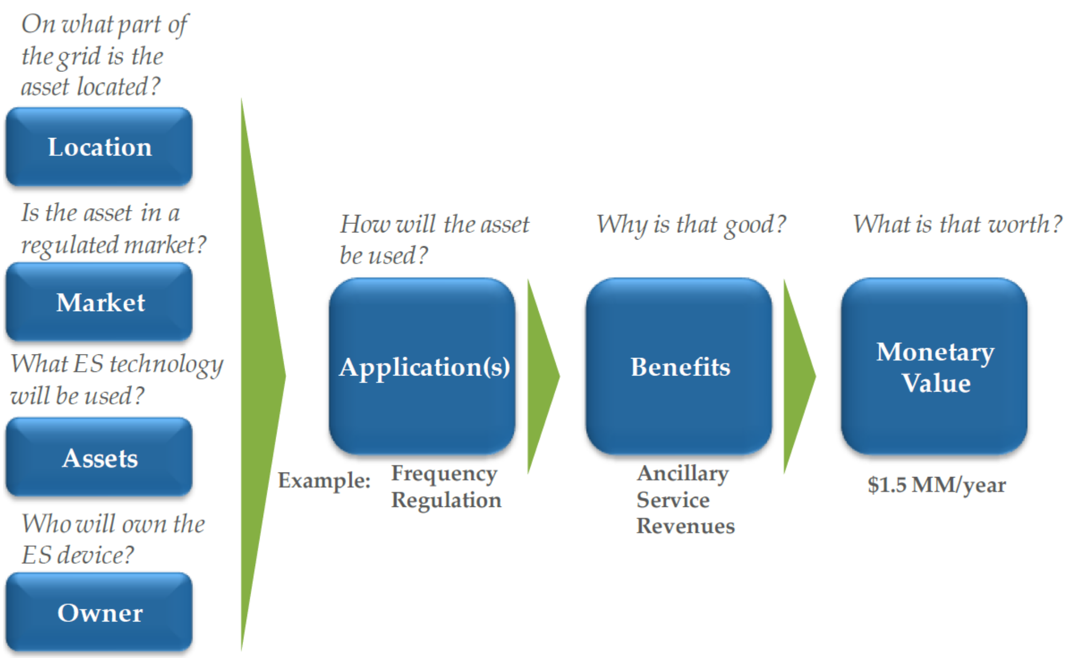
Baseline and project operational data will be gathered in accordance with the Operational Demonstration/Test Plans established for each demonstration application. KCP&L will then report data and impact metrics to the DOE as required. KCP&L will attempt to directly measure the baseline and project metrics required by SGCT. However, due to the number of Smart Grid Applications to be operationally demonstrated and tested, it may prove impractical to directly measure these annualized values. When necessary, shorter duration testing results will be extrapolated to annualized values for SGCT purposes.

2.5.2 Energy Storage Computational Tool Analysis [23]

Building on the methodology developed for evaluating the performance, costs, and benefits of Smart Grid projects, the DOE has developed a standard methodology and tool for evaluating the cost benefit of Energy Storage deployments.

The KCP&L Demonstration will use the DOE-developed Energy Storage Computational Tool (ESCT) to evaluate the overall costs and benefits in order to estimate the project's overall value. The ESCT allows the user to identify the key characteristics of the energy storage deployment and how the energy storage system will be used. Figure 2-92 illustrates how the ESCT determines the monetary value for energy storage deployments. KCP&L will use the ESCT to perform separate analysis for the utility Battery Energy Storage System and the customer Premise Energy Storage System.

Figure 2-92: System ESCT Methodology for Determining the Monetary Value of an ES Deployment



2.5.2.1 Battery Energy Storage System Analysis

Using the ESCT, the SGDP team input the energy storage asset information, grid location, market, and ownership for the BESS. Based on these inputs, the ESCT identified the expected benefits the BESS could achieve. Table 2-22 identifies the expected benefits by Energy Storage Application.

Table 2-22: ESCT Application-Benefit Matrix for KCP&L BESS Analysis

				Utility/Ratepayer						Societal			
Location	Market	Owner	Application	Optimized Generator Operation	Deferred Generation Capacity Investments	Deferred Transmission Investments	Deferred Distribution Investments	Reduced Electricity Losses	Reduced Electricity Cost	Reduced CO2 Emissions	Reduced SOx Emissions	Reduced NOx Emissions	Reduced PM Emissions
Distribution	Regulated	Utility	Electric Energy Time-shift										
Distribution	Regulated	Utility	Electric Supply Capacity										
Distribution	Regulated	Utility	Transmission & Distribution (T&D) Upgrade Deferral										

BESS operational data will be gathered in accordance with the Operational Demonstration/Test Plans established for each demonstration application. KCP&L will attempt to directly measure the metrics required by ESCT. However, due to the number of Smart Grid Applications to be operationally demonstrated and tested, it may prove impractical to directly measure these annualized values. When necessary, shorter duration testing results will be extrapolated to annualized values for ESCT purposes.

2.5.2.2 Premise Energy Storage System Analysis

Using the ESCT, the SGDP team input the energy storage asset information, grid location, market, and ownership for the PESS. Based on these inputs, the ESCT identified the expected benefits the PESS could achieve. Table 2-23 identifies the expected benefits by Energy Storage Application.

Table 2-23: ESCT Application-Benefit Matrix for KCP&L PESS analysis

			Utility/Ratepayer					Consumer		Societal			
Market	Owner	Application	Optimized Generator Operation	Deferred Generation Capacity Investments	Deferred Transmission Investments	Deferred Distribution Investments	Reduced Electricity Losses	Reduced Electricity Cost	Reduced Outages	Reduced CO2 Emissions	Reduced SOx Emissions	Reduced NOx Emissions	Reduced PM Emissions
Regulated	End-User	Time-of-use (TOU) Energy Cost Management											
Regulated	End-User	Electric Service Reliability											
Regulated	End-User	Renewables Energy Time-shift											

PESS operational data will be gathered in accordance with the Operational Demonstration/Test Plans established for each demonstration application. KCP&L will attempt to directly measure the metrics required by ESCT. However, due to the number of Smart Grid Applications to be operationally demonstrated and tested, it may prove impractical to directly measure these annualized values. When necessary, shorter duration testing results will be extrapolated to annualized values for ESCT purposes.

2.5.3 KCP&L Go-Forward Benefit/Cost Analysis of Demonstration Technologies

KCP&L developed a DRAFT SmartGrid Vision, Architecture, and Road Map discussion document in 2008 as a potential guide to future KCP&L investments in advanced distribution technologies. The document produced was a technology road map focused on the deployment of the advanced distribution technologies needed to implement the SmartGrid functions as described in Title XIII of the Energy Independence and Security Act of 2007 (EISA).

With the passage of the American Recovery and Reinvestment Act of 2009 (ARRA) in February 2009, it became apparent that the SmartGrid deployments outlined in the draft road map may be too aggressive and possibly premature from a technology perspective. The architecture, on which the plan was developed, was based on prior EPRI IntelliGrid^{SM} research. It was unclear to what extent the NIST SmartGrid Interoperability Framework initiative funded by ARRA may change KCP&L's future SmartGrid architecture design and technology selections.

With technology architecture uncertainties and the aggressive schedule of the ARRA funded Smart Grid Investment Projects (3 years), KCP&L management decided to focus on pursuing a DOE Smart Grid Demonstration Project. KCP&L is using its SGDP to:

- Define, implement & test a number of advanced distribution technologies and a smart grid system architecture based on the evolving NIST Smart Grid Interoperability Framework and Standards.
- Define and document the requirements of the various SmartGrid functions, technologies, and systems for potential future deployment company wide.

- Test, measure, analyze, and document the benefits of the various SmartGrid functions, technologies, systems, and grid operating practices.

The advanced distribution grid technologies being evaluated through KCP&L's SGDP are foundational, enabling technologies that will provide traditional operational benefits to the utility while enabling new demand side management and pricing programs; integration of utility and customer owned distributed generation; greater grid utilization through increased monitoring and control of grid resources; and enhanced utilization of customer demand response capabilities.

Upon completion of the SGDP, KCP&L plans to use the findings of the project to develop a well-founded SmartGrid Vision, Architecture, and Road Map that will provide the framework for evaluating the feasibility and guiding the implementation of SmartGrid technologies and will become an integral component of future IRP analysis and filings.

In developing the SmartGrid Road Map, KCP&L will use the build and impact metrics from the project and other DOE and EPRI Smart Grid Projects to perform a cost/benefit analysis of each of the advanced distribution grid technologies considered for the road map.

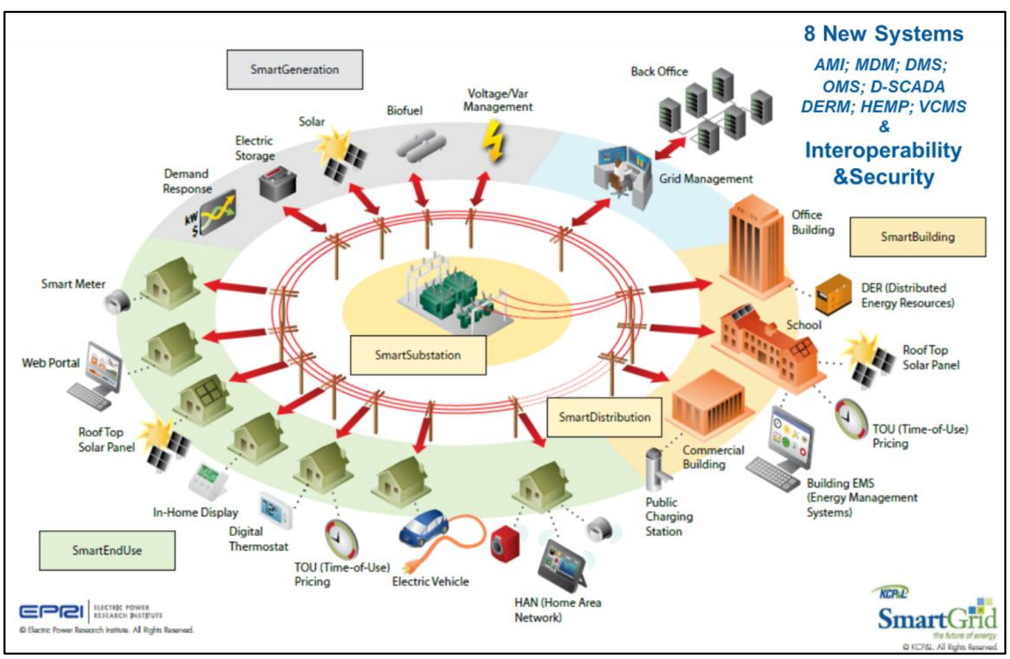
KCP&L anticipates that the results of the SGDP and subsequent benefit cost analyses will determine that several of the SmartGrid demonstration technologies will be cost effective, or at a minimum, KCP&L will understand under what conditions they become cost effective.

3 RESULTS

The primary objective of the KCP&L SGDP was twofold: (a) to demonstrate, test and report on the feasibility of combining, integrating and applying existing and emerging smart grid technologies and solutions to build innovative smart grid solutions, and (b) to demonstrate, measure, and report on the costs, benefits, and business model viability of the demonstrated solutions. The proposed technologies and solutions were evaluated both individually, and as part of a complete end-to-end integrated smart grid system in a defined geographical area. The project demonstrated certain operational, economic, consumer, and environmental benefits that can be enabled by specific smart grid technologies and further enhanced by integrated solutions as implemented for this demonstration.

This section of the report documents and summarizes results from the implemented smart grid technologies as demonstrated in the KCP&L SGDP. Project results are organized and presented in the following subsections:

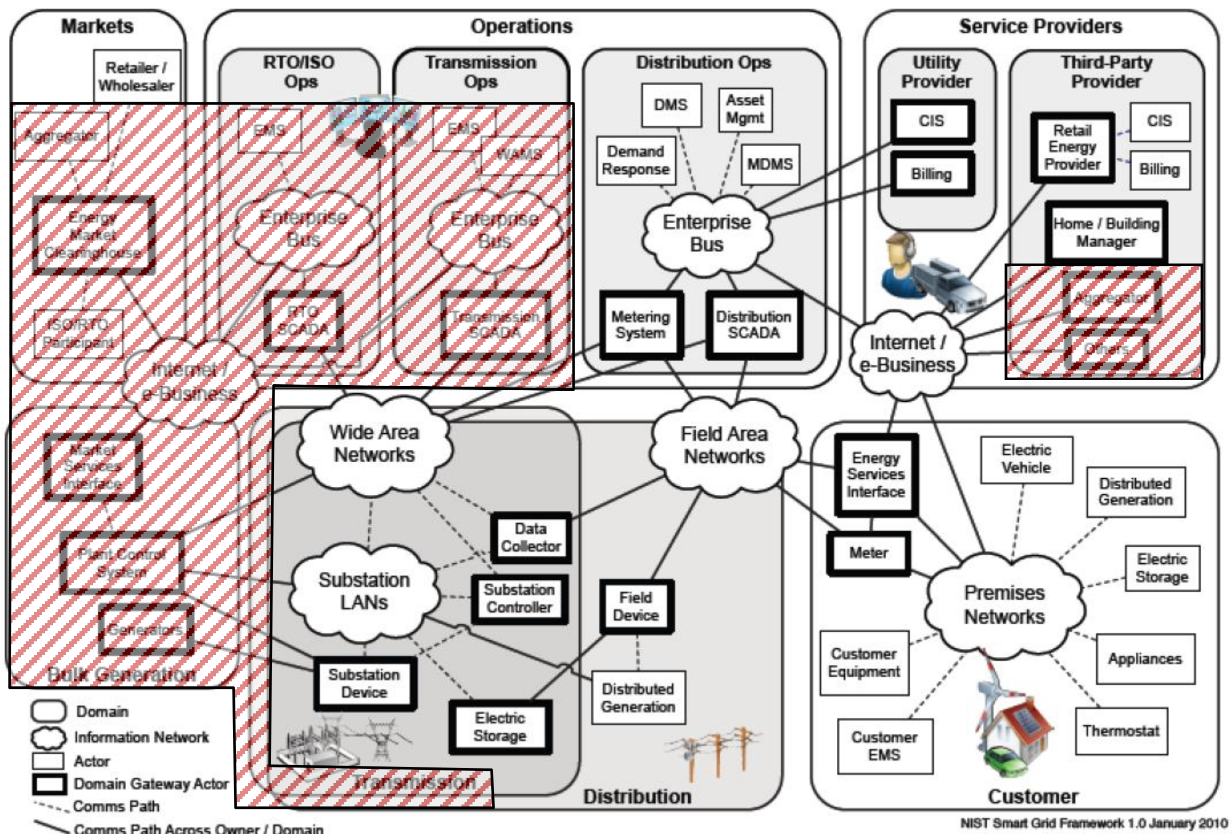
- Interoperability – summarizes the integration and interoperability design process used for the project and presents the resulting smart grid systems integration that was implemented.
- Cyber Security – presents a summary of the Risk Assessment performed for the SGDP and an overview of the risk mitigation strategies, cyber security controls, and physical security controls implemented on the project.
- Education & Outreach – contains as summary of the education and outreach initiatives undertaken as part of the project.
- Operational Testing– summarizes results of 24 different DOE Smart Grid Functions tested – with respect to desired vs. actual performance, and lessons learned.
- Metrics & Benefits Analysis – presents the project build and impact metrics and summarizes the benefits analysis performed using the DOE Smart Grid and Energy Storage Computational Tools.
- Stakeholder Feedback – presents some of the feedback received from various stakeholders (e.g., ratepayers, regulators, vendors) regarding the impacts of smart grid technologies and functions.



3.1 Interoperability [7]

The KCP&L SGDP's main objective is to demonstrate an end-to-end grid management system that involves the integration of ten new systems/sub-systems, from six project vendor partners, and seven legacy KCP&L systems. Figure 3-6 illustrates the scope of the project demonstration integration relative to the NIST Logical Interface Reference Mode. To meet the integration challenges associated with ensuring interoperability across the SGDP, KCP&L used a structured methodology highlighted in Section 2.1.1. The following sections provide the integration and interoperability design results from the application of this methodology.

Figure 3-1: KCP&L Project vs. NIST SmartGrid Logical Interface Reference Model



3.1.1 Integration Requirement Planning

The KCP&L SGDP demonstrates an end-to-end grid management system that involves the integration of ten new systems/sub-systems and seven legacy KCP&L systems. With this large of an integration project the development of a common project understanding between all project participants was essential to project success.

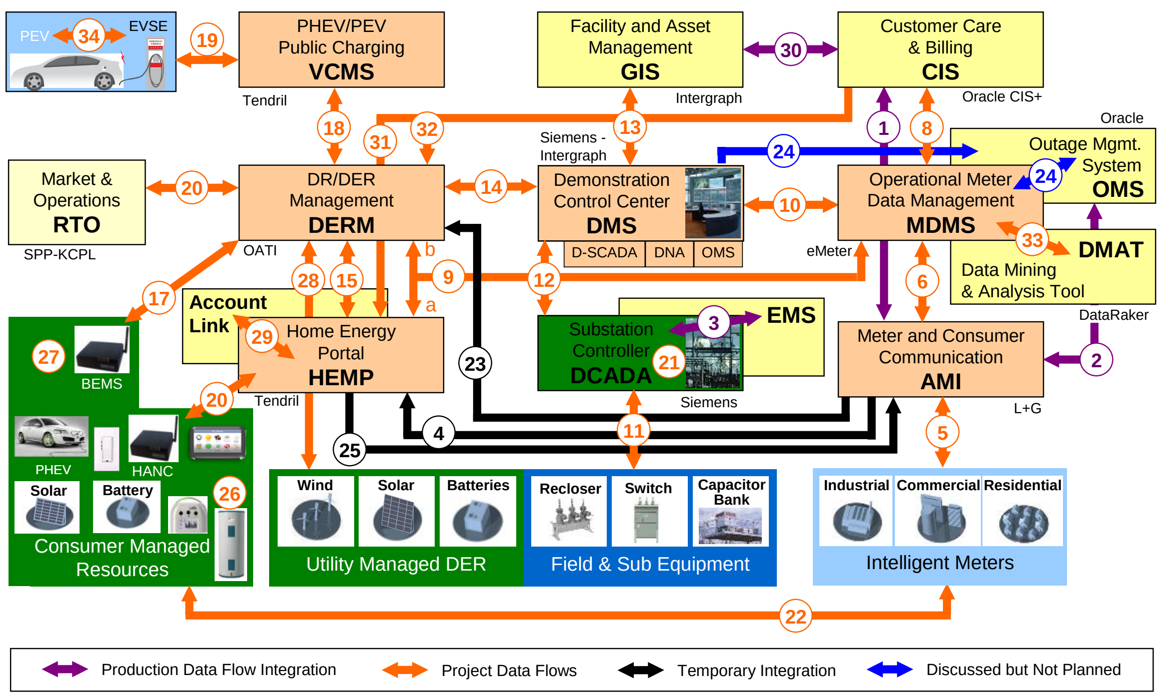
To reach this common understanding KCP&L initiated a series of conceptual design workshops and work efforts beginning in November 2009. Each workshop was facilitated by KCP&L and was attended by subject matter experts from each vendor partner, KCP&L enterprise architects, KCP&L SGDP resources, and KCP&L subject matter experts. Approximately 30 KCP&L employees and 20 vendor partner participants were involved in the workshops.

The objectives of these initial efforts were to:

- Gain a high level understanding of role and functions of each of the new systems/sub-systems
- Establish an understanding of the functionality that the integrated solution is to demonstrate
- Identify and resolve any functionality gaps and overlaps in vendor products and the proposed integration
- Identify and characterize the nature of each of the major project integration points

Through these initial project scoping efforts, 33 potentially significant integration points were identified and characterized. These interfaces are illustrated in Figure 3-2.

Figure 3-2: KCP&L SmartGrid Demonstration Systems Interfaces



3.1.2 Integration and Interoperability Requirement Definition

Use cases identify detailed workflows and the corresponding functional requirements for the KCP&L SGDP implementation. Additionally, these use cases identify the data exchange points between the SmartGrid systems and devices using a Common Information Model (CIM) design, which allows the systems to exchange information independent of the manufacturer or vendor. This is important as utilities seek to actively deploy systems and devices from multiple manufacturers.

3.1.2.1 EPRI-Assisted Use Cases

As a member of EPRI's five-year Smart Grid Demonstration Program, KCP&L's demonstration system integration and interoperability requirements definition and design were supported through EPRI's formalized Smart Grid Demonstration Program. The SGDP team leveraged EPRI's IntelliGrid^{SM} [10] methodology to define the technical foundation for the project that links electricity with communications and computer control systems to achieve gains in reliability, capacity, and customer services.

The IntelliGrid℠ process is a structured methodology for identifying requirements based on business use cases. The IntelliGrid℠ methodology is an open-standards, requirements-based approach for integrating data networks and equipment that enables interoperability between products and systems. This methodology provides tools and recommendations for standards and technologies when implementing systems such as advanced metering, distribution automation, and demand response and also provides an independent, unbiased approach for testing technologies and vendor products.

KCP&L and EPRI launched the formal IntelliGrid℠ methodology Use Case process for the project on August 12, 2010. EPRI assisted the KCP&L project team in applying the IntelliGrid℠ methodology to develop an initial set of four use cases:

1. First-Responder Applications – DCADA identifies feeder overload conditions and responds accordingly
2. Distributed Hierarchical Monitoring and Control – Interface between the DMS and DCADA Integration
3. Distributed Energy Resource Management – DMS to DERM Integration
4. Customer Demand Response

3.1.2.2 KCP&L-Developed Use Cases

The KCP&L SGDP has continued to develop use cases to define the integration requirements for the entire project. In total, more than 110 use cases have been identified to cover the entire breadth of the KCP&L SGDP. The use cases have been organized into the following groupings:

- Automated Meter Information (AMI)
- Meter Data Management (MDM)
- SmartSubstation (SUB)
- First Responder (1^{ST})
- Distribution Management System (DMS)
- Demand Response Management (DRM)
- Distributed Energy Resources (DER)
- SmartEnd-Use (SEU)
- Home Area Network (HAN)
- Plug-In Electric Vehicle (PEV) Charging
- Communications Network (NWK)

The KCP&L SGDP team has identified the Use Cases listed in Table 3-1 as the basis for defining project functionality and interoperability requirements and test plans. A summary description of each Use Cases is presented in Appendix B.

Table 3-1: SmartGrid Demonstration Project Use Cases

ID	Use Case Title
AMI-01	Customer Initiated Remote Service Order Completion
AMI-02	Utility Initiated Remote Service Order Completion (Future)
AMI-03	On Demand Meter Read
AMI-04	On-Demand Meter Status Check
AMI-05	Automated Daily Meter Read
AMI-06	SmartMeter Alarm Events
AMI-07	SmartMeter Advisory Events
AMI-08	SmartMeter Log Only Events
AMI-09	SmartMeter Source Power Events
AMI-10	AMI FAN Device Alarm Events

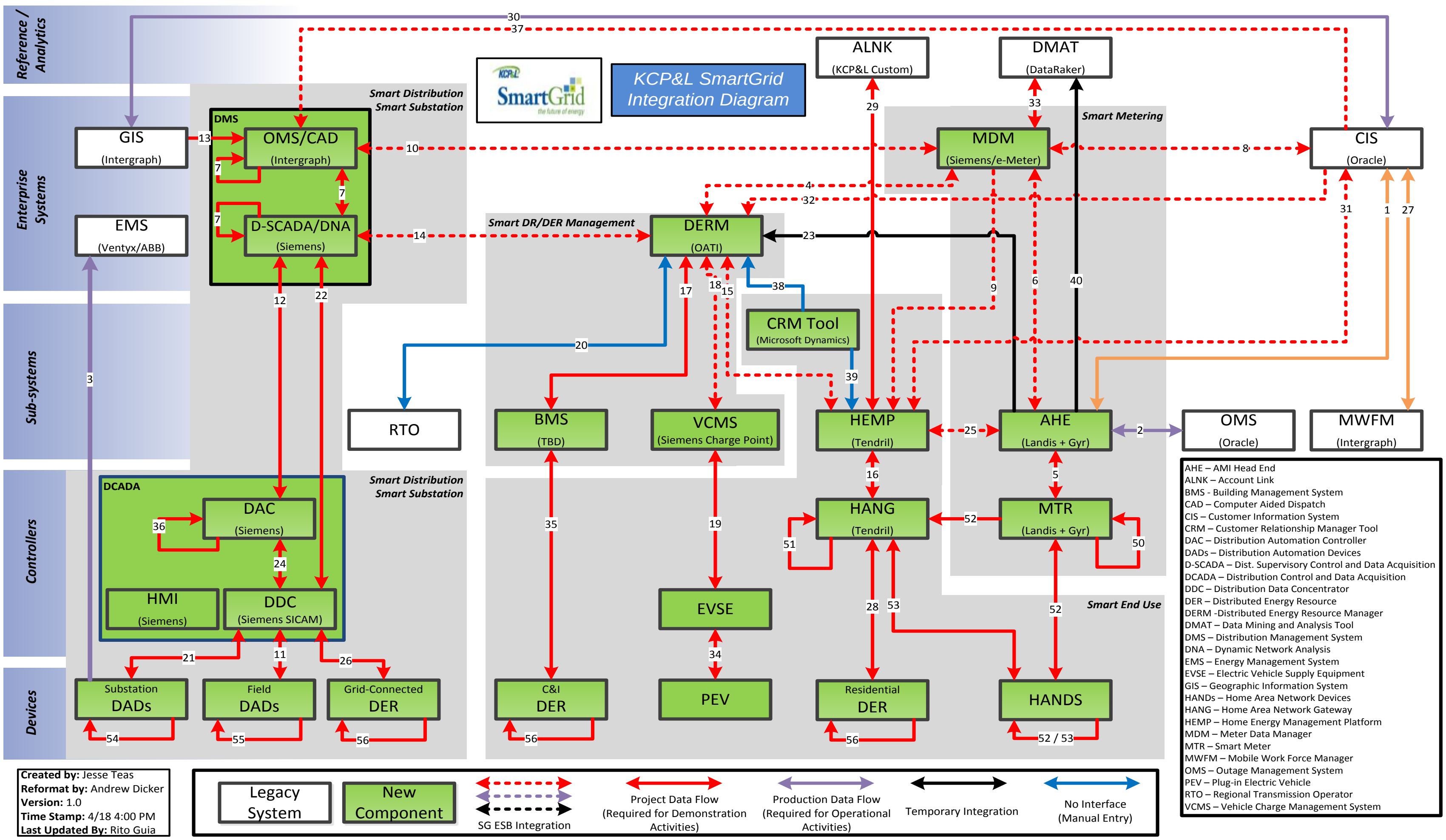
ID	Use Case Title
AMI-11	AMI FAN Device Advisory Events
AMI-12	AMI FAN Device Log Only Events
AMI-13	Remote SmartMeter Update
AMI-14	Field SmartMeter Update
AMI-15	Remote AMI FAN Device Update
AMI-16	Field AMI FAN Device Update
AMI-17	SmartMeter Replaced by Field Crew (Future)
MDM-01	MDM Distributes Daily Service Delivery Point Updates (Future)
MDM-02	MDM Distributes Daily Meter Data
MDM-03	MDM Creates Billing Determinants
MDM-04	SmartMeter Inventory Management (Future)
SUB-01	DCADA Monitors and Controls Substation Devices
SUB-02	DCADA Monitors and Controls Field Devices
SUB-03	DCADA Monitors Equipment for Condition-Based Maintenance Programs
SUB-04	Substation IEC 61850 GOOSE Protection Schemes
SUB-05	Substation Transformer Dissolved Gas Analysis and Thermal Monitoring (Future)
SUB-06	Substation Transformer Dynamic Ratings (Future)
SUB-07	Feeder Cable Dynamic Ratings (Future)
1ST-01	DCADA Performs Fault Detection, Location, Isolation, and Restoration
1ST-02	DCADA Performs Volt/VAR Management
1ST-03	DCADA Performs Dynamic Voltage Control (Future)
1ST-04	DCADA Performs Localized Feeder Load Transfer
1ST-05	DCADA Initiates Relay Protection Re-coordination (Future)
DMS-01	DMS Network Model Maintenance
DMS-02	DMS Monitors and Controls Substation Devices
DMS-03	DMS Monitors and Controls Field Devices
DMS-04	DMS Monitors and Controls Grid Battery
DMS-05	DMS Coordinates Control Authority Responsibility with DCADA
DMS-06	DMS Processes Protective Device Alarms for Outage Analysis
DMS-07	DMS Performs Emergency Load Transfer
DMS-08	DMS Schedules Required Load Transfer
DMS-09	DMS Initiates Load Reduction with DERM
DMS-10	DMS Performs Fault Detection, Location, Isolation, and Restoration
DMS-11	DMS Operator Returns Grid to NORMAL Configuration
DMS-12	DMS Performs Volt/VAR Management
DMS-13	DMS Performs Dynamic Voltage Control
DMS-14	DMS Initiates Relay Protection Re-coordination (Future)
DRM-01	DERM Network Model Maintenance
DRM-02	DR/DER Resource/Asset is Registered in DERM
DRM-03	DERM Manages DR/DER Resource Availability
DRM-04	DERM Creates DR/DER Event for DMS Load Reduction
DRM-05	DERM Creates DR/DER Event for Power Market Operations (Future)
DRM-06	DERM Distributes Demand Response Information Messages (Future)
DRM-07	DERM Distributes DR/DER Event Schedules to Resource/Asset to Control Authority
DRM-08	HEMP Manages DR Events for HAN Connected Resources
DRM-09	DRAS Manages DR Events for AMI Connected Resources
DRM-10	DRAS Manages DR Events for Commercial Building Resources (Future)
DRM-11	CBMS Manages DR Events for Commercial Buildings (Future)
DRM-12	VCMS Manages DR Events for EV Charging Stations
DRM-13	DMS Manages DR Events for DVC and Grid Connected DER
DRM-14	Verification of DR/DER Event Participation
DRM-15	DERM Generates Retail Pricing Signals (Future)
DER-01	Utility Operates Grid Storage for Capacity and Economic Benefits
DER-02	Utility Operates Grid Storage for T&D Asset Deferral and Power Quality
DER-03	Utility Operates Grid Storage for Service Continuity
DER-04	Customer Installs Premise Solar PV Distributed Generation
DER-05	Customer Installs Premise Energy Storage System in Conjunction with Solar PV

ID	Use Case Title
DER-06	Customer Operates Premise Energy Storage System for Economic Benefits
DER-07	Utility Installs Grid Connected Rooftop Solar Distributed Generation
DER-08	Utility Operates Premise Energy Storage System for Grid Benefits
SEU-01	Customer Views Historical Energy Information via HEMP
SEU-02	Customer In-Home Display – Basic Functions
SEU-03	Customer In-Home Display – Daily Bill True-Up
SEU-04	Customer In-Home Display – Prepayment (Future)
SEU-05	Customer Uses HEMP to Register HAN Gateway
SEU-06	Customer Uses HEMP to Provision HAN Device to HAN Gateway
SEU-07	Customer Uses HEMP to Monitor Real Time Usage via HANs
SEU-08	Customer Uses HEMP for Programmable Communicating Thermostat Mgmt.
SEU-09	Customer Uses HEMP for Load Control Switch Management
SEU-10	Customer Uses HEMP to Opt Out of DR Event
SEU-11	Customer Initiates De-Provisioning of Customer HAN Device
SEU-12	Customer Enrolls in Time Based Pricing Program
SEU-13	Customer Configures HEMP with Energy Usage Preferences (Future)
SEU-14	Customer Uses HEMP to Respond to Energy Signals (Future)
SEU-15	Customer Uses HEMP to Manage PV and PESS (Future)
SEU-16	Customer Uses HEMP to Manage PEV Charging (Future)
HAN-01	Utility Commissions Home Area Network
HAN-02	Utility Provisions HAN Device to SmartMeter
HAN-03	Utility Sends Text Message to HAN Device
HAN-04	Utility Cancels Text Message
HAN-05	Utility Sends Pricing Signals to SmartMeter and HAN Devices
HAN-06	Utility Home Area Network Device Information
HAN-07	Utility De-Provisions HAN Device on Utility Home Area Network
HAN-08	Utility De-Commissions Utility Home Area Network
HAN-09	HAN Device Vendor Change Control (Future)
HAN-10	HAN Device Status Check (Future)
PEV-01	PEV Charging at a Public Charge Station
PEV-02	Customer Participated in Utility PEV Charging Program
PEV-03	Customer Registers PEV to Home Premise (Future)
PEV-04	Customer PEV Charging at Home Premise (Future)
PEV-05	Un-Registered PEV Charging at Premise EVSI (Future)
PEV-06	Charge Validation and Settlement via Clearinghouse (Future)
PEV-07	Utility Controls PEV Charging at Public Charge Station (Future)
PEV-08	Utility Controls Customer On-Premise PEV Charging (Future)
NWK-01	AMI Field Automation
NWK-02	DA Field Automation Network
NWK-03	Utility Home Area Network
NWK-04	Customer Home Area Network
NWK-05	Public EV Charge Network
NWK-06	Substation Distribution Automation Network
NWK-07	Substation Distribution Protection Network

3.1.2.3 Project Integration/Interface Points

Through the use case requirement definition efforts, the SGDP team identified additional integration/Interface points. These interfaces are illustrated graphically in Figure 3-8. Appendix C provides initial design characterizations for each of the identified interfaces.

Figure 3-3: KCP&L SmartGrid Systems Integration



3.1.3 SmartGrid Application Integration Architecture Design

One of the objectives of the project is to demonstrate end-to-end interoperability using the NIST SmartGrid Framework architecture. As Illustrated in Figure 3-1 and Figure 3-3, the KCP&L SGDP integration architecture design is closely aligned with the NIST Framework and Roadmap for Smart Grid Interoperability Standards. The following subsections provide an overview of the integration architecture being implemented.

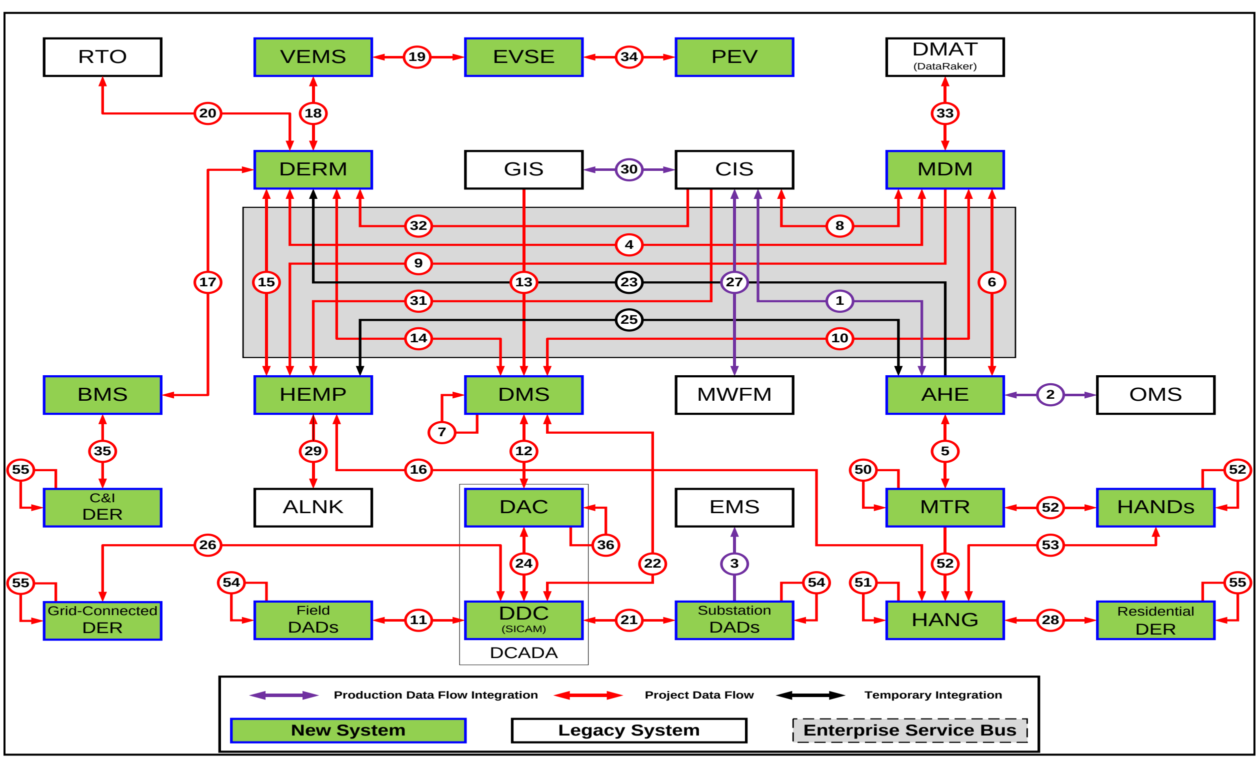
3.1.3.1 SmartGrid Enterprise Service Bus Framework

An Enterprise Service Bus (ESB) refers to a software architecture construct. This construct is typically implemented by technologies found in a category of middleware infrastructure products, usually based on recognized standards, which provide foundational services for more complex architectures via an event-driven and standards-based messaging engine (the bus).

The IEC 61968 series of standards is intended to support the inter-application integration of a utility enterprise that needs to connect disparate applications that are already built or new (legacy or purchased applications), each supported by dissimilar runtime environments. Therefore, these interface standards are relevant to loosely coupled applications with more heterogeneity in languages, operating systems, protocols, and management tools. This series of standards—which are intended to be implemented with middleware services that exchange messages among applications—support applications that need to exchange data every few seconds, minutes, or hours rather than waiting for a nightly batch run. They will complement—not replace—utility data warehouses, database gateways, and operational stores.

Figure 3-4, the KCP&L SmartGrid Master Interface Diagram, introduces the ESB and identifies the interfaces that should be considered for implementation with the ESB instead of point-to-point interfaces.

Figure 3-4: KCP&L SmartGrid Master Interface Diagram

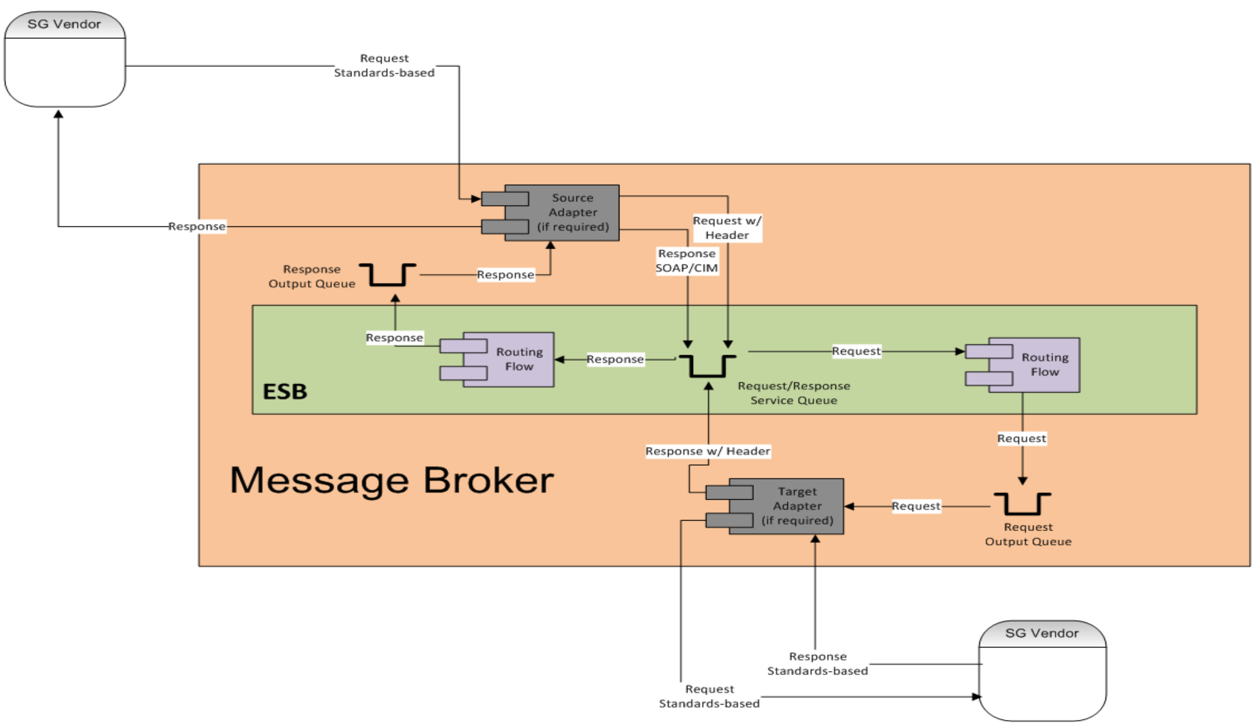


As KCP&L does not currently utilize an ESB in its legacy architecture, the project is leveraging prior EPRI work [24] in developing the project's ESB framework to implement the SmartGrid system to system integration depicted in Figure 3-3 and Figure 3-4. The ESB framework will define how the message payloads will be conveyed using Web Services and the Java Message Service (JMS).

The ESB implemented for the SGDP as illustrated in Figure 3-5 has been based on the following constructs:

- The SmartGrid ESB will utilize the existing KCP&L IBM Websphere MQ and IBM Websphere Message Broker as messaging platform and communication backbone
- The SmartGrid ESB will manage all routing flows and transport requirements using IBM Websphere MQ
- The SmartGrid ESB will implement a series of application adapters using IBM Websphere Message Broker
- The application adapters will manage any message translation, transformation, and/or any mediation required
- Any/all exchange of information between SmartGrid vendor partners must be routed and transported through KCP&L's network and SmartGrid ESB, where appropriate
- All SmartGrid vendor application must communicate to the SmartGrid ESB application adapters using Web Services, JMS, or MQ messaging
- Auditing capabilities will be implemented to log the state of the message as it flows through the ESB

Figure 3-5: KCP&L SmartGrid ESB Framework Example



3.1.4 Interoperability Standards

The development of the SGDP Transmission & Distribution infrastructure involves many standards and numerous levels of integration. One of the objectives of the project is to demonstrate end-to-end interoperability using the following NIST SmartGrid Framework identified interoperability standards. The following subsections list the standards that have been incorporated into the project.

3.1.4.1 Back-Office Systems Integration Standards

- International Electrotechnical Commission (IEC) 61968-1 for general systems and application-level interface architecture
- IEC 61968-3/61970 for application-level interfaces between the DERM and DMS
- IEC 60870-6/TASE.2 (Inter-Control Center Communications Protocol, ICCP) for real-time internal DMS communications
- IEC 61968-9 for application-level interfaces with the AMI, Meter Data Management System (MDMS), CIS, and DMS
- OpenADR 2.0 for demand response interfaces between DERM and DR control authorities: HEMP, DMS, Building Energy Management System (B-EMS) and VCMS

3.1.4.2 Field Device Communication Standards

- IEC 61850 for substation automation and communication with distributed resources
- IEC 61850 for communication to distributed automation (DA) devices over the Field Area Network (FAN) (when available)
- Distributed Network Protocol (DNP) 3.0/Internet Protocol (IP) for communication to DA devices over the FAN

3.1.4.3 In-Home Communication Standards

- OpenHAN for HAN device communication, measurement, and control architecture
- ZigBee for meter-based utility-managed HAN (UHAN) devices
- ZigBee and Wi-Fi for customer-managed HAN (CHAN) devices
- Smart Energy Profile 1.x for UHAN communications
- Smart Energy Profile 2.x for CHAN communications

3.1.4.4 Standards Maturity Impact

Many of the Smart Grid Standards identified above have continued to evolve during the course of the SGDP, often at a much slower pace than anticipated by SGIP, the industry, and the project team. Other Standards, while having some adoption within transmission systems, have very limited vendor adoption at the distribution level. The lack of Smart Grid Standards maturity had a significant impact on project team's ability to implement the designed integration flows outlined previously in Section 3.1.2.3. These impacts have been discussed in each of the System Implementation overviews presented in Section 2. Appendix L of this document provides the as-implemented characterizations for each of the systems integration points illustrated in Figure 3-3: KCP&L SmartGrid Systems Integration.

3.2 Cyber Security

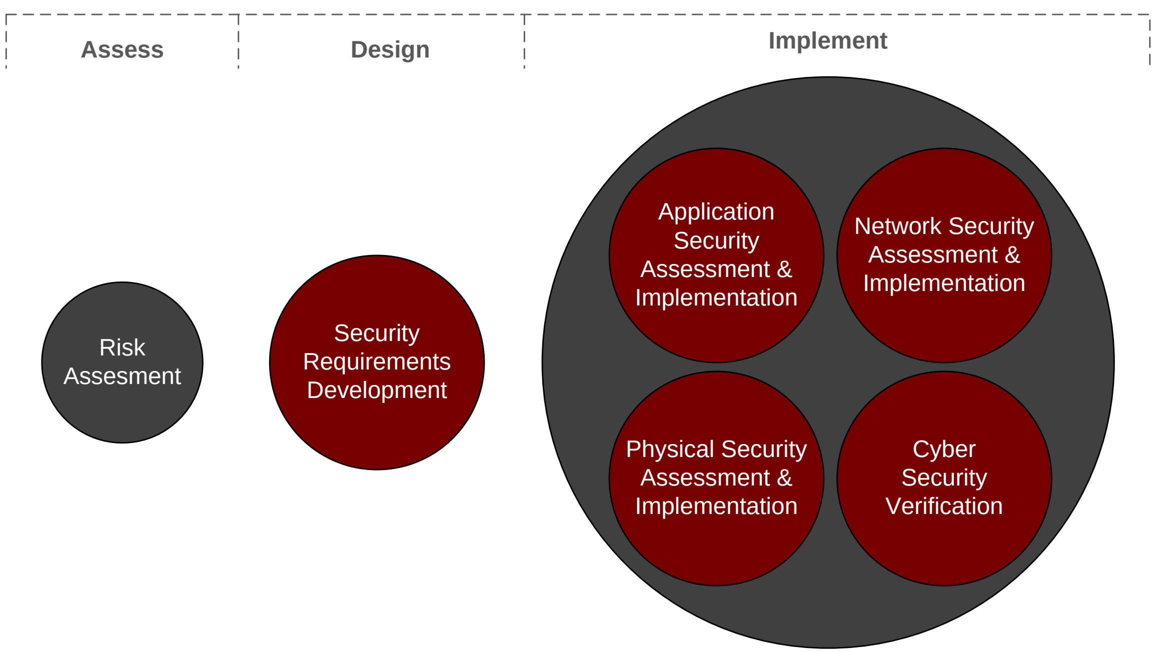
KCP&L chose to conduct a comprehensive risk assessment of all the systems within their SGDP. KCP&L made this decision to meet the requirements set forth in both their SmartGrid Cyber Security Plan [13] and the U.S. Department of Energy (DOE) Smart Grid Demonstration funding announcement [25] that states implementing sound cyber security controls for all smart grid systems.

To follow the KCP&L SmartGrid Cyber Security Plan, the risk assessment performed for the project was primarily based on the guidelines provided in the National Institute of Standards and Technology (NIST) in their Special Publication 800-30 – Guide for Conducting Risk Assessments (NIST SP 800-30) [14]. The NIST Interagency Report 7628 Volumes I-III (NISTIR-7628) [15] and the UCA [26] International Users Group's Advanced Metering Infrastructure and Distribution Management (UCAIug AMI and UCAIug DM) Security Profiles were also used to conduct the analysis and provide cyber security suggestions for the KCP&L project.

KCP&L chose to focus on and address several areas of cyber security threats in the implementation of its SGDP. The focused cyber security threat areas included (but were not limited to): autonomous systems and malicious code, external attack, insider abuse and unauthorized acts, insider attack, legal and administrative actions, physical intrusion and/or theft and violent acts of man.

KCP&L developed and executed an effective cyber security plan tailored to identify, assess, and mitigate threats, risks, and vulnerabilities related to KCP&L's SmartGrid implementation. The cyber security plan focused on three execution focus areas (see Figure 3-6). The first execution focus area (Assess) comprised of conducting a risk assessment of the KCP&L SGDP systems. The second focus area (Design) included creation and distribution of security requirements based on the risk assessment results to both KCP&L and vendor application developers. The third focus area (Implement) included four parallel sub-focus areas: Application Security Assessment & Implementation, Physical Security Assessment & Implementation, Network Security Assessment & Implementation, and Cyber Security Verification.

Figure 3-6: Cyber Security Plan Execution Focus Areas



3.2.1 Risk Assessment [27]

A complete risk assessment based on the NIST SP 800-30 was performed for twenty-one smart grid systems. The risk assessment results provided:

- Impact-based classifications for all smart grid systems
- Risk ratings for all smart systems
- Approaches for developing security requirements

Separate methodologies were developed to calculate the values of the risk rating model components: threat, vulnerability, likelihood, impact, and mitigation. Each methodology was applied uniformly to all systems to determine values of the components. The following subsections provide an overview of the risk assessment methodology and results. For more information, please see Appendix M for the risk assessment document in its entirety.

3.2.1.1 Scope of Assessment

As a prerequisite to the risk assessment, all systems within the KCP&L SmartGrid portfolio were identified along with their respective interfaces. This step formed the boundaries of the scope and created a foundation for the assessment. The resultant scope of the risk assessment was identified to include the smart grid systems listed in Table 3-2.

For the systems that were included in the scope, several methods were used to develop a deeper understanding of KCP&L's implementation of smart grid technologies. These methods included the review of system documents such as use cases, interface diagrams, and vendor software specifications. In addition, focus group interviews with the Subject Matter Experts (SMEs) were performed using a set of targeted questions. The result was a grouping of smart grid systems into several business function domains that were later used as one of the criteria to recommend the creation of security zones. The collaborative work with the SMEs also resulted in the classification of all system interfaces into one of the NIST-specified logical interface categories. This classification was later used to determine the security controls that were required to secure the systems.

Table 3-2: Smart Grid Systems Included in the KCP&L Risk Assessment

Smart Grid Systems included in the Risk Assessment	Commonly Referred as:
Advanced Metering Infrastructure Head-End	AHE
AccountLink	ALNK
Building Management System	BMS
Customer Information System	CIS
Distributed Control and Data Acquisition	DCADA
Distributed Energy Resources – Commercial & Industrial	DER – C&I
Distributed Energy Resources – Grid-Connected	DER – Grid-Connected
Distributed Energy Resources Management System	DERM
Distributed Energy Resources – Residential	DER – Residential
Data Mining and Analysis Tool	DMAT
Distribution Management System	DMS
Energy Management System	EMS
Field Distribution Automation Devices	Field DADs
Geographic Information System	GIS
Home Area Network Devices	HANDs
Home Area Network Gateway	HANG
Home Energy Management Platform	HEMP
Meter Data Management System	MDM
SmartMeter	MTR
Mobile Workforce Management System	MWFM
Substation Distribution Automation Devices	Substation DADs

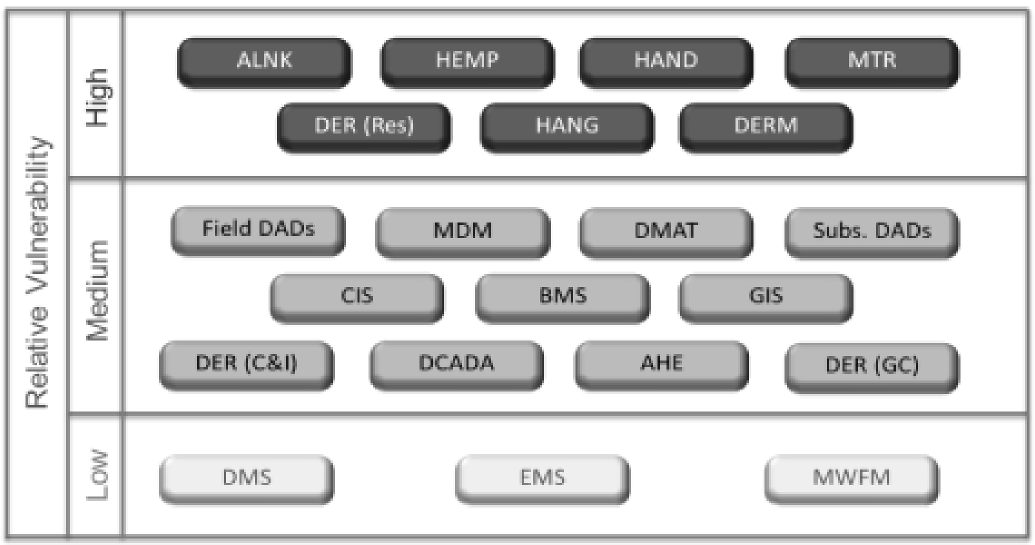
3.2.1.2 Risk Quantification

In order to assess the value of the threat component in the risk model, several internal and external threat sources were identified. The assessment not only included threat sources with an intention to harm the organization but also those resulting from unintentional acts and natural occurrences. Once the threat sources were identified, a list of motivations and possible threat actions taken by each threat source was produced. The value of the threat component for each system was determined by evaluating whether each threat source could impact the system. This value for each system thus equated to the number of threat sources identified to pose a risk to that system.

Vulnerability is defined as the susceptibility of a system to attacks. In the risk assessment, systems were evaluated for the broad categories of system vulnerabilities and operational vulnerabilities. System vulnerabilities directly affect one of the three cyber security goals of confidentiality, integrity, and availability. Operational vulnerabilities were further categorized into people, policy and procedural vulnerabilities. To provide a numerical value to the vulnerability of a system, an approach was used to quantify two of the fundamental reasons that make a system vulnerable. The resulting two variables were the relative technical ease of coordinating an attack and the relative ease of access to parts of the system.

A summary of the relative vulnerability ratings of the smart grid systems is graphically represented in Figure 3-7, where each system is placed in either the Low, Medium, or High region.

Figure 3-7: Graphical Representation of Relative Vulnerability Ratings

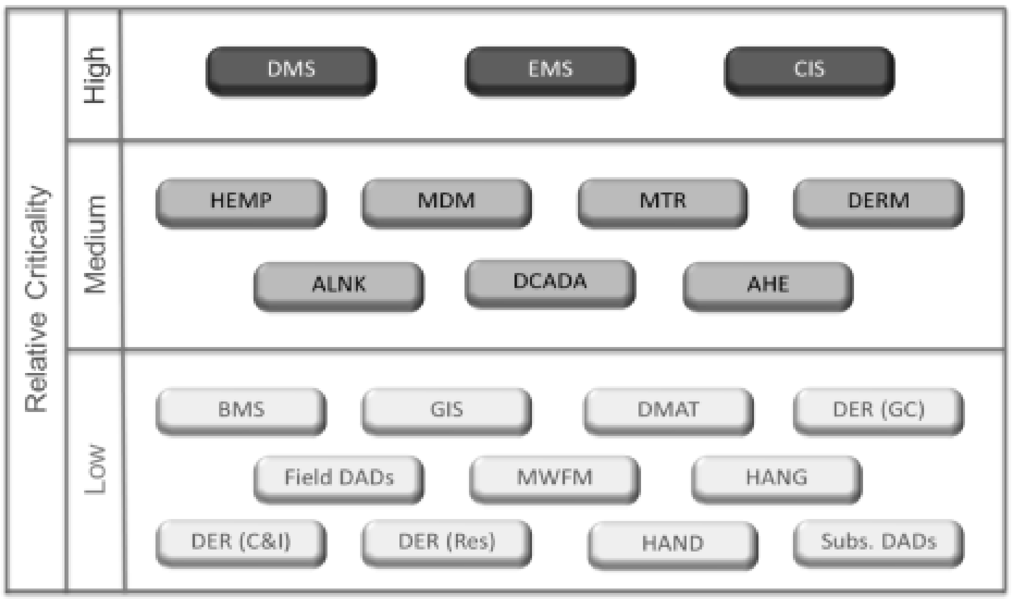


Several measurement criteria were used to assess the likelihood of an attack. These criteria included the evaluation of a potential threat source's motivation and capabilities as well as the nature and frequency of existing vulnerabilities. In the risk assessment, this component did not represent the likelihood of a successful attack, but merely the likelihood of an attack. Similar to the other risk model components, a rating methodology was developed to assign a value for likelihood to all systems. Each threat source was applied to each system and its likelihood of an attack was given a rating. The highest assigned likelihood rating among the threat sources for a system was then used as that system's overall likelihood rating.

Impact (also referred to as criticality) can be defined as the effect or influence a successful attack may have on a system and/or the organization. Examples of impact include significant monetary damage, compromised consumer privacy, loss of important business operations for long periods of time, national-level damage to company reputation, and years of litigation. For the risk rating model, a quantifying approach was developed to estimate the effects that a cyber-compromise of confidentiality, integrity, and/or availability would have on the system and the organization. The confidentiality impact was judged based on the qualitative assessment of the sensitivity of the system's data and the effects of a data leak event. The integrity impact was assessed in terms of the cost of fixing a data integrity issue. Lastly, the availability impact was evaluated by considering the cost of lost productivity, lost opportunity, lost business image, or increased business cost caused if each system became unavailable for a certain length of time.

A summary of the relative criticality ratings of the smart grid systems is graphically represented in Figure 3-8, where each system is placed in the Low, Medium, or High region.

Figure 3-8: Graphical Representation of Relative Criticality Results



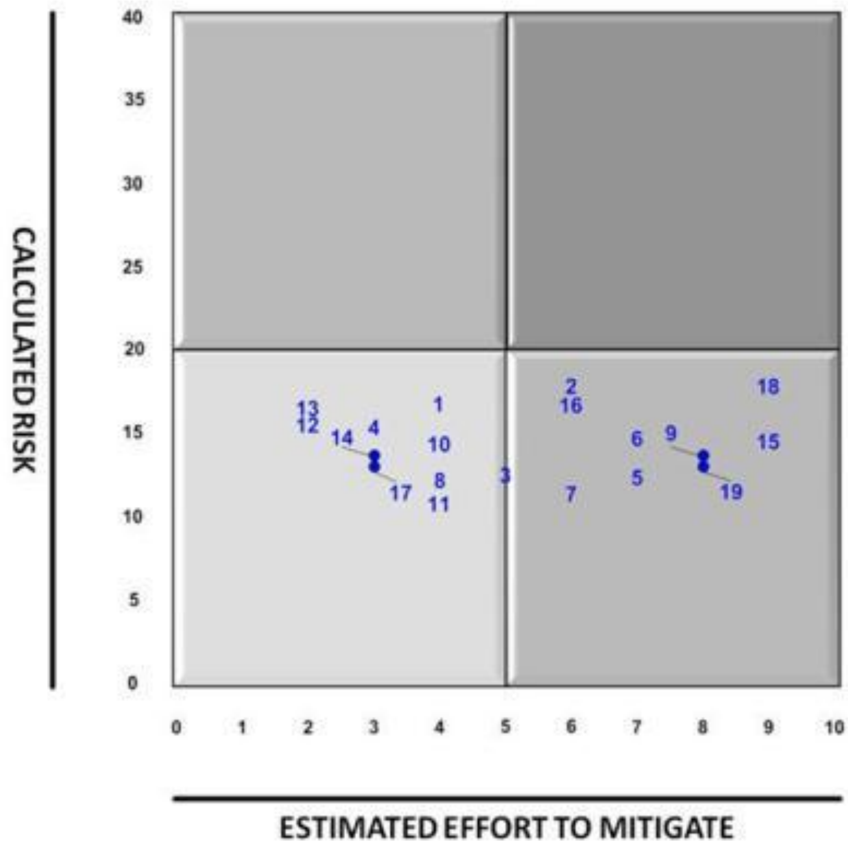
Mitigations are defined as risk reducing efforts or controls commissioned to protect a system's vulnerabilities or diminish the impact or likelihood of an attack on a system. To assess the value of the mitigation component, the cyber controls suggested in the NISTIR-7628 and the UCAIug AMI and DM Security Profiles were studied for their applicability to the KCP&L SmartGrid systems. Once the applicable sets of controls were identified, they were matched with the security controls mandated in KCP&L policies, standards, and processes. A methodology was created to quantify the existing mitigations so that they could be used in the risk rating model. The methodology was based on the assumption that all requirements stated in KCP&L policies, standards, and processes are enforced on all existing and new systems at KCP&L.

The primary purpose for the risk assessment was to identify the risk level of each smart grid system so that KCP&L could strategize its efforts towards securing the project as a whole. The prioritization task became less complex with a risk rating available for each system. The final risk rating for each system was calculated using the model:

$$Risk = Threat + Vulnerability + \ Likelihood + \ Impact - Mitigation$$

Once the risk ratings were calculated, the systems were plotted against an estimate of the effort required to further mitigate the systems' vulnerabilities, likelihoods, and impacts. Figure 3-9 shows the systems plotted against the calculated overall risk rating and estimated effort to mitigate.

Figure 3-9: Risk Rating Categories



System ID	System
1	AHE
2	ALNK
3	BMS
4	CIS
5	DADs (Field & Substation)
6	DCADA
7	DER - C&I
8	DER – Grid-Connected
9	DER - Residential
10	DERM
11	DMAT
12	DMS
13	EMS
14	GIS
15	HAND/HANG
16	HEMP
17	MDM
18	MTR
19	MWFM

There is not, nor should there be, an "ideal" level of risk or a static "target" level of risk at which to aim. Calculated risk ratings should be used to prioritize efforts to reduce overall system risk. Risk may be reduced by mitigations and controls applied at the policy, network, or system level.

3.2.1.3 Risk Assessment Recommendations

There were ten major recommendations given in the risk assessment report. Some were technical in nature, such as assessing and implementing recommended security controls, or designing and implementing recommended network security zones. Others were more policy- and process-based, such as updating policies and documenting mitigation activities. The following list is an overview of the ten major recommendations:

- Implement the provided sets of security controls in a phased approach
- Implement the recommended conceptual security zones using network design techniques
- Create an implementation plan that covers the recommended security controls and security zones
- Update the KCP&L SmartGrid Cyber Security Plan to maintain focus on security and to meet DOE expectations
- Create security requirements for all systems to convert the security controls from concept to implementation
- Develop minimum security requirements for any smart grid system externally hosted by a third-party
- Update KCP&L policies, standards, and/or processes to include protection of smart grid systems based upon the provided set of procedural controls

- Create and execute test cases to verify the placement and functionality of the security controls
- Perform periodic security assessments to identify and mitigate new risks
- Participate in working groups to learn and create best practices and standards for securing the grid

3.2.2 Risk Mitigation

The completion of the risk assessment resulted in a set of actionable mitigation steps that were taken by KCP&L to make its smart grid systems secure. The KCP&L SmartGrid Trust Model [13] was also used as an important reference while creating these mitigation recommendations. The KCP&L Trust Model domains (Secured, Restricted, Controlled, and Uncontrolled) were used to develop recommended security zones for KCP&L SmartGrid systems and to determine the security controls for data stored and/or generated by the systems. The Trust Model transport classes (Trusted, Managed, and Public) were used to determine the security controls for data transmitted between systems.

The mitigation recommendations resulting from the risk assessment fell into one of the following two types of security control implementations: creation of security zones and implementation of tailored control sets or implementation of industry-suggested control sets. Detailed descriptions of both security control implementations are covered in the following subsections.

3.2.2.1 Creation of Security Zones and Implementation of Tailored Control Sets

This type of security control implementation included a collection of security controls specifically tailored for the SGDP based upon security zones and interfaces between security zones. Each security zone included smart grid systems that have the same criticality level and perform similar business functions. The goal of this implementation was to incorporate controls that bring high risk systems down to a medium risk level and adequately protect the systems based on their impact levels. As such, the selection of controls in this type of implementation was also based on the risk and impact ratings calculated for each system as part of the end-to-end risk assessment.

Figure 3-10 below provides a graphical view of the recommended security zones for the KCP&L SGDP.

Second, security control sets were created that tailor to the security zones and interfaces between them. Each control set was a collection of security requirements from the NISTIR-7628 Volume-I as well as many of the ones included in the UCAIug [26] AMI and DM Security Profiles. Figure 3-11 provides a visual representation of the control sets applicable to each security zone and its interfaces.

Figure 3-10: Representation of Smart Grid Applications in Respective Security Zones

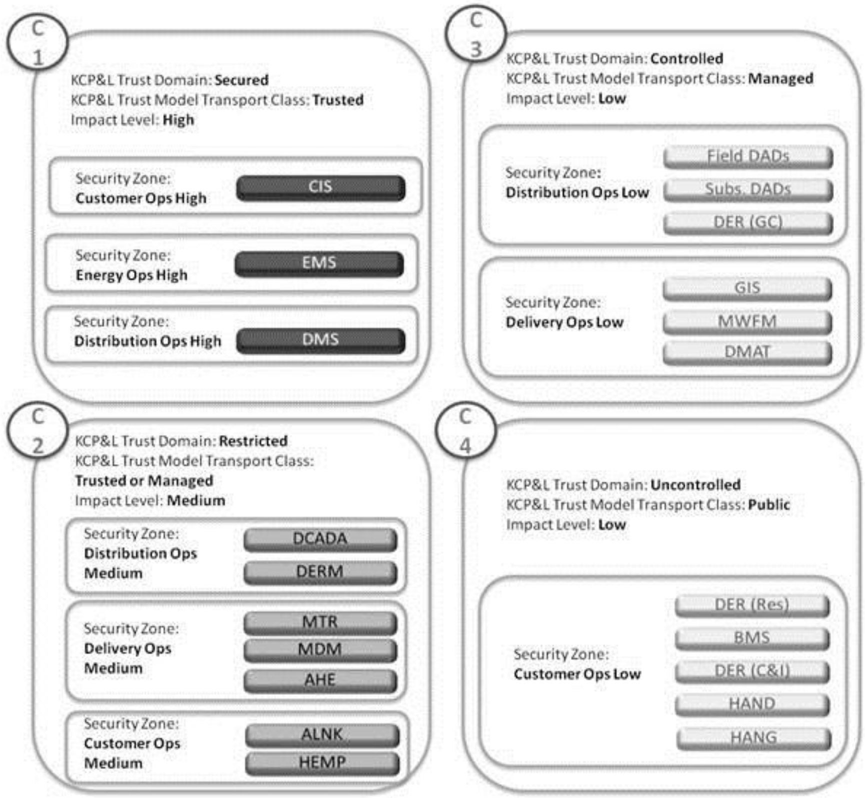
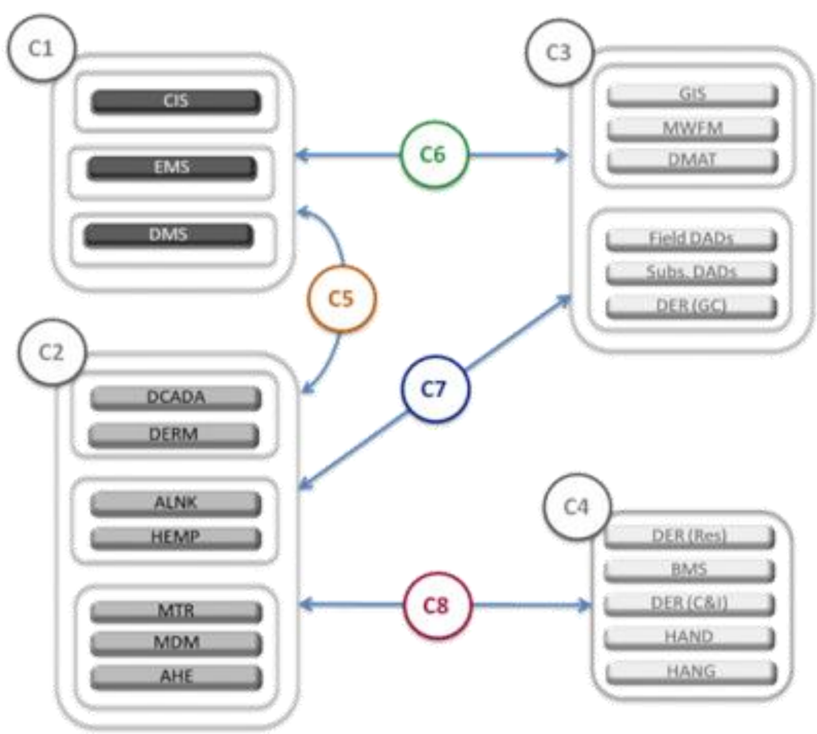


Figure 3-11: Representation of Control Sets for Inter-Security Zone Communication



3.2.2.2 Industry-Suggested Controls

The second type of security control implementation was a collection of controls based on industry best practices and guidelines. This type consisted of all the controls recommended in the NISTIR-7628 Volume-I [15] based strictly on the applicable logical interface categories. These security requirements, if implemented to their fullest, should adequately secure the smart grid systems. It is worth noting that the controls recommended in the implementation type discussed in Section 3.2.2.1 are a subset of the controls recommended in this type.

Table 3-3 provides a summarized listing of the KCP&L SmartGrid systems along with their applicable NISTIR-7628 Logical Interface Categories. The table indicates that a majority of the NISTIR-7628 security requirements were found to be applicable to all the smart grid systems. To improve readability and act as a quick reference, the table lists requirements in the format "All except…" the requirements found *not* to be applicable.

Table 3-3: NISTIR-7628 Security Requirements Applicability by System

SmartGrid System	Applicable NISTIR-7628 Logical Interface Categories	Applicable NISTIR-7628 Security Controls
AHE	5, 13, 14	**All** Except: SG.AC-12, SG.IA-5, SG.SC-4, SG.SC-17
BMS	15	**All** Except: SG.AC-11, SG.AC-12, SG.AU-16, SG.IA-5, SG.SC-4, SG.SC-6, SG.SC-9, SG.SC-17, SG.SC-26, SG.SC-29
CIS	7, 8, 10	**All** Except: SG.SC-6, SG.SC-9, SG.SC-17
DCADA	1, 2, 3, 5	**All** Except: SG.AC-12, SG.AU-16, SG.SC-4, SG.SC-9, SG.SC-17, SG.SC-26
DER - C&I, **DER - Grid-Connected,** **DER - Residential**	11	**All** Except: SG.AC-11, SG.AC-12, SG.AC-14, SG.AU-16, SG.IA-4, SG.IA-5, SG.IA-6, SG.SC-3, SG.SC-4, SG.SC-5, SG.SC-6, SG.SC-7, SG.SC-9, SG.SC-17, SG.SC-26, SG.SC-29, SG.SI-7
DERM	8, 9, 16	**All** Except: SG.SC-6, SG.SC-17, SG.SC-29
DMS	5, 10	**All** Except: SG.AC-12, SG.AU-16, SG.IA-5, SG.SC-3, SG.SC-9, SG.SC-26
EMS	1	**All** Except: SG.AC-12, SG.AU-16, SG.SC-4, SG.SC-6, SG.SC-9, SG.SC-26
Field DADs, Substation DADs	11	**All** Except: SG.AC-11, SG.AC-12, SG.AC-14, SG.AU-16, SG.IA-4, SG.IA-5, SG.IA-6, SG.SC-3, SG.SC-4, SG.SC-5, SG.SC-6, SG.SC-7, SG.SC-9, SG.SC-26, SG.SC-29, SG.SI-7
GIS	10	**All** Except: SG.AC-12, SG.AU-16, SG.IA-5, SG.SC-3, SG.SC-6, SG.SC-9, SG.SC-26
HAND, HANG	15	**All** Except: SG.AC-11, SG.AC-12, SG.AU-16, SG.IA-5, SG.SC-6, SG.SC-4, SG.SC-9, SG.SC-26, SG.SC-29
HEMP	8, 16	**All** Except: SG.SC-5, SG.SC-6, SG.SC-29
MDM	7, 8, 10	**All** Except: SG.SC-6, SG.SC-9
MTR	15	**All** Except: SG.AC-11, SG.AC-12, SG.AU-16, SG.IA-5, SG.SC-4, SG.SC-6, SG.SC-9, SG.SC-26, SG.SC-29

3.2.3 Security Requirements Development

Using the tailored control sets from the risk assessment as a basis, KCP&L evaluated the security controls provided in the NISTIR-7628 to determine which controls were applicable to each system in the project for the following areas:

- Application Security
- Physical Security
- Network Security
- Policy/Procedural Controls

The NISTIR-7628 security controls are separated into nineteen controls families predominantly based upon NIST SP 800-53. KCP&L found at least one control from all nineteen families to be applicable to the smart grid systems in the SGDP. Here is a list of the control families:

- Access Control (AC)
- Awareness and Training (AT)
- Audit and Accountability (AU)
- Security Assessment and Authorization (CA)
- Configuration Management (CM)
- Continuity of Operations (CP)
- Identification and Authentication (IA)
- Information and Document Management (ID)
- Incident Response (IR)
- Smart Grid Information System Development and Maintenance (MA)
- Media Protection (MP)
- Physical and Environmental Security (PE)
- Planning (PL)
- Security Program Management (PM)
- Personnel Security (PS)
- Risk Management and Assessment (RA)
- Smart Grid Information System and Services Acquisition (SA)
- Smart Grid Information System and Communication Protection (SC)
- Smart Grid Information System and Information Integrity (SI)

KCP&L focused its security requirements evaluation on the new systems being deployed in the SGDP. For each new system being implemented, KCP&L determined which party would be responsible for implementing the desired security controls: KCP&L, the vendor(s), or a combination of KCP&L and the vendor(s). For the scope of the SGDP, KCP&L determined that a large subset of the security controls recommended in the tailored control sets (discussed in Section 3.2.2.1 above) were appropriate. Table 3-4 shows the systems that KCP&L developed security requirements for as part of the SGDP along with the number of NISTIR-7628 controls found to be applicable from each control family. For more information, please see Appendix N for the master spreadsheet that lists the specific controls found to be applicable for each of these smart grid systems.

Table 3-4: Master Security Controls

NISTIR-7628 Controls Family	Quantity of Applicable Controls						
	MDM	AHE	DERM	HEMP	DMS	DCADA DDC	BESS
Access Control	16	17	16	18	17	17	14
Awareness and Training	4	4	4	4	4	4	2
Audit and Accountability	11	11	11	11	12	12	12
Security Assessment and Authorization	6	6	6	6	6	6	6
Configuration Management	9	9	9	9	11	11	11
Continuity of Operations	8	8	8	8	10	10	9
Identification and Authentication	6	6	6	6	6	6	6
Information and Document Management	4	4	4	4	3	3	3
Incident Response	10	10	10	10	11	11	11
Smart Grid Information System Development and Maintenance	4	4	4	4	4	4	4
Media Protection	6	6	6	6	6	6	6
Physical and Environmental Security	10	10	10	10	11	11	11
Planning	0	0	0	1	4	4	4
Security Program Management	2	2	2	2	5	5	5
Personnel Security	8	8	8	8	8	8	8
Risk Management and Assessment	1	1	1	1	6	6	6
Smart Grid Information System and Services Acquisition	9	9	9	9	10	10	10
Smart Grid Information System and Communication Protection	17	17	17	17	19	19	18
Smart Grid Information System and Information Integrity	8	8	8	8	9	9	9

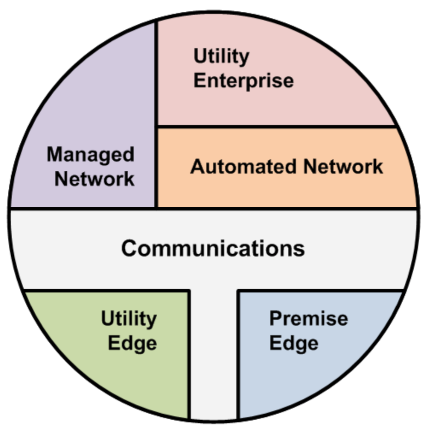
In addition to developing a list of applicable security controls for each smart grid system, KCP&L reviewed the design methodologies presented in the UCAIug Security Profiles (primarily for AMI and DM) for key cyber security issues and assessed their applicability to the SGDP.

For the AMI Security Profile, one of the concepts KCP&L focused on was the AMI Security Service Domains, which were discussed in Section 4.4 of that document. The domains identified in the profile are:

- Utility Enterprise
- Automated Network
- Managed Network
- Communications
- Utility Edge
- Premise Edge

KCP&L concentrated on the profile's recommendation that communication should only be allowed to flow between domains that are shown as having a common boundary as shown in Figure 3-12. In other words, KCP&L wanted to ensure that other utility enterprise systems (part of the Utility Enterprise domain) such as OMS, DMS, or MDM would not have direct access to components of the AMI FAN (part of the Communications domain). Only the AHE (part of the Automated Network domain) or devices running field tools (part of the Managed Network domain) should have direct access to components of the AMI FAN. Furthermore, there should be a logical separation between the different components of the AMI meter itself. For instance, the HAN interface of the meter (part of the Premise Edge domain) such as a ZigBee radio should not be able to directly control the utility-owned and operated components of the meter such as the disconnect switch (part of the Utility Edge domain).

Figure 3-12: AMI Security Service Domains [28]



For the DM Security Profile, KCP&L focused on a similar concept but one tailored toward network segmentation. In Section 4.1 of the profile, UCAIug recommends that any DM network architecture should be separated into the four following segments:

- DM Field Network
- DM Control Systems Server Network
- DM Controls Systems User Network
- Non-DM Utility Network

All four of the above segments should be private networks. Furthermore, only the Non-DM Utility Network segment should have direct access to public networks (such as the Internet). The other three segments should not have access to the Internet. In addition, only the DM Control Systems Server Network should have access to the DM Field Network. That is, the DM Control Systems User Network should not have direct access to the DM Field Network. DM users should interact with some sort of user interface that communicates (behind the scenes) to the DM back office or substation servers, which in turn handle direct communication to the DM devices in the field or substation.

3.2.4 Application Security Assessment & Implementation

After determining what controls were applicable for each system, KCP&L developed and provided security requirements comprised of security controls from the NISTIR-7628 to the system vendor via security surveys. For each requirement, the survey asked for the following responses:

- Specify whether the requirement is covered by responding "Yes", "No", or "Planned"
  - If "Yes", provide the technical details of implementation
  - If "No", provide reason
  - If "Planned", provide planned date for conformity and technical details of implementation
- If requirement is covered, list the tests performed that validate that the requirement has been met
- Provide and list the supporting test documentation (cases, procedures, results, etc.)

In addition to the questions about specific NISTIR-7628 controls, KCP&L also asked a series of general questions of the vendors that hosted a smart grid system:

- Specify whether there is an alternate data center in place to back up the system
- If so, specify whether it is protected the same way as the primary data center
- Specify whether any penetration tests have been performed on the system
- If so, provide results
- Specify whether the vendor has had any third-party security controls reviews performed
- If so, provide results
- Specify what types of encryption methods the system supports

A sample of a security survey sent to the system vendors is provided in Figure 3-13 below.

Figure 3-13: Excerpt from System Vendor Cyber Security Survey

NISTIR 7628 Smart Grid Requirement Number	NISTIR 7268 Smart Grid Requirement Name	Is Requirement Implemented? (Yes/No/Planned)	If **Yes**: Provide technical details of implementation. If **No**: Provide a reason why. If **Planned**: Provide planned date of implementation and technical details of implementation.	If requirement has been implemented, please list the tests performed that validate the requirment being met.	Please list the supporting test documentation (cases/procedures, results) that is supplied to KCP&L as part of this questionnaire.
SG.AC-1	Access Control Policy and Procedures				
SG.AC-2	Remote Access Policy and Procedures				
SG.AC-3	Account Management				
SG.AC-4	Access Enforcement				

As part of the Implement focus area, KCP&L assessed responses to the security surveys to evaluate the cyber security readiness for both KCP&L and vendor-hosted systems as follows:

- If security requirements are met
- How security requirements are met
- If any third-party assessment (NISTIR-7628, NERC CIP, SSAE 16, etc.) have been performed
- What organizational controls will be implemented by either KCP&L or the vendor
- What shared organizational controls will be implemented by both KCP&L and the vendor
- What technical controls will be developed by either KCP&L or the vendor

KCP&L experienced a variety of responses from the vendors during this process. Some of them were quite responsive and willing to provide detailed feedback. Others were not as receptive at first but after more discussion, KCP&L was able to receive their responses to the survey. Unfortunately, there were a couple of vendors that were not willing to fill out the survey. One of these vendors agreed to discuss their security posture on a series of conference calls, while the other one provided the results of a third-party security assessment for KCP&L to review. In both cases, KCP&L applied the vendor's feedback to the security survey in order to approximate how well the vendors security posture lined up with the requirements.

After assessing the various responses received by the system vendors, KCP&L identified what gaps were present for each system. The project team then either chose to implement additional security controls to cover the gaps (where feasible) or to accept the associated risk for the gaps as deemed appropriate within the scope of the SGDP. Due to the confidential nature of the security survey results, they have not been included in this report.

3.2.5 Physical Security Assessment & Implementation

As part of the Implement focus area, KCP&L evaluated physical security controls for the KCP&L-hosted systems and one of the vendors -hosted systems (see Section 3.2.7 for more information on the vendors -hosted system). To establish a high level of physical access control and monitoring, the project team:

- Assessed the existing controls at the KCP&L corporate data center and found them to be appropriate for the SGDP
- Assessed the existing controls in the KCP&L operations control room and found them to be appropriate for the SGDP
- Designed physical security zones and requirements for the SGDP substation
- Designed and implemented physical security zones and requirements for the SmartGrid Innovation Park
- Verified the controls that one of the vendors has in place within their hosting facilities

Before implementation, KCP&L first designed a model for the physical security zones for both the SGDP substation and SmartGrid Innovation Park. The project team first identified all the various physical access points that existed in the substation and that were planned for the park. This consisted of any gates, doors, panels, or cabinets that did or would allow physical access to one or more smart grid assets. Then, KCP&L identified the various personnel roles that would require admittance through each of these access points:

- Corporate Security
- Distribution Operations (C&M Crews, Cable Splicers, Linemen, Metermen, etc.)
- Information Technology (Network Engrs., Systems Engrs., Telephone Techs., etc.)
- Transmission Operations (Relay Techs, Sub Electricians, Sub & System Protection Engrs.)
- Smart Grid Team
- Vendors
- General Public

After identifying the applicable personnel roles and which physical access points they would need clearance for, KCP&L determined how they wanted to implement access control for each of these access points. This consisted of either electronic access via a keycard reader or a physical key. In addition, the project team determined what types of mitigation would be required for the perimeter of each site and certain access control points within each site. This consisted of video surveillance, intrusion detection, and motion detection.

After designing physical security zones and requirements, KCP&L assessed the existing controls at the SGDP substation and found them to be appropriate for the scope of the project. For the SmartGrid Innovation Park, the project team implemented a physical security architecture that closely followed the security zones and physical security requirements that were developed earlier in the project.

KCP&L implemented access control for the perimeter of the SmartGrid Innovation Park using physical keys—different keys for the vehicle gate versus the pedestrian gate since each gate was intended for different types of personnel roles and purposes. Physical keys were also used to secure access to the grid-connected BESS and inverter (SMS) enclosures as well as the server and network racks inside the battery control enclosure. The project team implemented electronic card readers for access control to the battery control enclosure itself.

For mitigation measures, KCP&L implemented a combination of video surveillance, intrusion detection, and motion detection. Video cameras were installed to monitor the vehicle gate and pedestrian gate as well as the doors to the BESS, SMS, and battery control enclosures. In addition, the project team positioned the video cameras not only to monitor the perimeter but also numerous angles throughout the interior of the SmartGrid Innovation Park. KCP&L implemented intrusion detection via electronic card readers on the vehicle and pedestrian gates. Thus, if anyone without clearance attempts to gain physical access to the site, the local security system generates an alarm and sends it to KCP&L Corporate Security for notification. The project team implemented motion detection by installing microwave motion sensors along the perimeter of the park. Similar to the electronic card readers, the microwave motion detection system generates events and alarms and sends them to KCP&L Corporate Security for notification.

KCP&L utilized a local digital video recorder (DVR) to consolidate all of the video feeds captured by the video cameras installed throughout the SmartGrid Innovation Park. In addition, the project team utilized a local security panel to collect and analyze the various events detected by the electronic card readers and microwave motion sensors and to generate alarms as needed. Both the DVR and security panel utilized the KCP&L Corporate WAN backhaul to send their data upstream to the back office Corporate Security systems (see Section 3.2.6 for more information). Thus, new physical security controls were implemented as part of the SGDP, but they were incorporated into KCP&L's existing corporate physical security infrastructure.

3.2.6 Network Security Assessment & Implementation

As part of the Implement focus area, KCP&L assessed the smart grid network architecture and related security requirements. Based upon the results of the risk assessment, the project team:

- Created KCP&L network segregation requirements
- Created KCP&L high-level network architecture both for the overall SGDP and within the SGDP substation
- Implemented a smart grid network isolated from the KCP&L corporate network
- Implemented point-to-point virtual private network (VPN) connections to vendors hosting smart grid systems
- Verified the network security architecture of one of the system vendor's hosting facilities

KCP&L used several different references when creating network segregation requirements for the SGDP:

- Security zones from the cyber security risk assessment
- Security controls from NISTIR-7628
- Security domains recommendations from UCAIug AMI Security Profile
- Network segmentation recommendations from UCAIug DM Security Profile

For more information on the security zones from the cyber security risk assessment, see Section 3.2.2. As part of the effort to develop security requirements for each system, KCP&L identified which NISTIR-7628 security controls were applicable to the design of the network. For more information on the development of the security requirements, see Section 3.2.3. To see a complete list of all the applicable NISTIR controls, see Appendix N. In addition, see Section 3.2.3 for an explanation of the security domains and network segmentation recommendations from the UCAIug Security Profiles for AMI and DM.

After establishing network segregation requirements, KCP&L focused on designing the network architecture for the SGDP. The project team first concentrated on the architecture for the SGDP substation as most of the network build-out would take place there. Within the SGDP substation network architecture, KCP&L implemented the following secure enclaves (graphically depicted in Figure 3-14):

- KCP&L Corporate Network – This network provides KCP&L personnel in either the existing SGDP substation control house or battery control enclosure access to systems on the corporate network and a connection to the Internet. In order to gain access to this network, KCP&L personnel were required to use a KCP&L-issued laptop. This network is an extension of the back office KCP&L corporate network.
- Substation Distribution Protection & Control Network – This network consists of redundant fiber optic ring networks that connect all of the Substation Distribution Automation Devices that are designed for protection and control (relays and tap changers). The communication within this network is high-speed IEC 61850 compliant – utilizing GOOSE messages to transmit necessary information in a peer-to-peer fashion for the relays' protection and control schemes.
- Smart Grid User Network – This network allows KCP&L personnel to access information displayed to DMS operators in the control center via a DMS workstation installed in the battery control enclosure. Role-based access control (RBAC) determines whether each user can access the DMS from the workstation as well as each user's privileges within the DMS if they have access. It is an extension of the back office Smart Grid User Network.
- Substation Distribution Automation & Asset Management Network – This network contains the systems that make the SGDP substation a "SmartSubstation". This is comprised of DCADA and the substation HMI. In other words, this is the network segment that contains the smart grid substation-based servers and thus functions as the substation control network. Any communication that needs to be transmitted between DCADA and DMS in the back office is backhauled via the KCP&L WAN. This network was originally intended to also include a separate system that would administer and control other substation distribution automation devices used for asset management. However, KCP&L decided to not implement this system as part of the scope of the SGDP.
- Substation Physical Security Network – This network consists of the security host devices (DVR and security panel) installed in the battery control enclosure. Each host device collects and analyzes information from the security devices installed throughout the SmartGrid Innovation Park (video cameras, electronic badge readers, and motion detectors). After analyzing the information, the hosts generate any necessary alarms and events and backhauls them to the back office Corporate Security servers via the KCP&L WAN.
- Distribution Automation Network –This wireless, mesh field area network provides a communication path for DCADA to monitor and control the grid-connected battery and Field Distribution Automation Devices (capacitor banks, FCIs, and reclosers). This network consisted of edge routers, base mesh nodes, and gateways. The edge routers are radios connected to each Field Distribution Automation Device. The base mesh nodes are radios used to extend the mesh network throughout the project area. The gateways are used to transmit messages on and off the Distribution Automation Network. KCP&L implemented two gateway locations for the SGDP—one at the SGDP substation and one near one of the KCP&L offices.

- Field AMI Network – This wireless, mesh field area network is used for communication between the SmartMeters installed throughout the project area. It also includes the AMI routers and collectors. The routers are used to extend the mesh network throughout the project area. The collectors serve as gateways for transmitting messages on and off the AMI network. The communication between the AMI collectors and AHE was originally backhauled utilizing a combination of the KCP&L WAN and the existing private T1 lines between KCP&L and Landis+Gyr. However, as part of the SGDP, KCP&L migrated the communication backhaul to one completely managed by Landis+Gyr. Thus, the Field AMI Network as well as all communication between the Field AMI Network and the AHE in the back office is now hosted by Landis+Gyr.

The three other secure enclaves shown in Figure 3-14 are the Substation Legacy T-SCADA Serial DNP Network, KCP&L TDM Telecom Network, and the KCP&L WAN. The first two are legacy networks and contain non IP-based communication. They exist alongside the IP-based network segments that KCP&L implemented as part of the SGDP. Their primary function is to collect status from the Substation Distribution Automation Devices (via serial-based communication) and backhaul the information to KCP&L's EMS. The KCP&L WAN serves as the corporate backhaul for IP-based communication. Even though the network already existed prior to the SGDP, the project team utilized it to backhaul communication from the substation to the back office.

Anything within each network segment implemented as part of the SGDP (bulleted list above) is allowed to communicate to one another freely as they are considered members of the same security zone. However, all communication between each network segment is restricted to the minimum ports and services required for necessary message transfers between systems. This restriction is implemented using firewall rules.

Next, KCP&L designed the infrastructure for the back office smart grid systems. This architecture is shown in Figure 3-15. Similar to the SGDP substation network layout, the back office network architecture consisted of a combination of new and existing network segments. KCP&L implemented the following new segments as part of the SGDP, which are shaded green in Figure 3-15:

- Smart Grid Operations Network – This network contains the back office smart grid servers, which in the case of KCP&L's implementation, are the DMS servers. If KCP&L had decided to also host the AHE, DERM, and MDM, they would have been considered part of this same segment.
- Smart Grid User Network – This network serves the same function as the one shown in the SGDP substation network architecture. However, this segment contains multiple DMS workstations and two smart grid terminal servers. The terminal servers are used as both DMS workstations and as a means for secure, remote access to the various smart grid systems that reside both in the back office and in the substation network segments.
- Smart Grid DMZ – This network serves as the termination point for the various third-party VPN connections (discussed in further detail below) that the project team implemented as part of the SGDP. To provide an additional layer of security, each third-party connection terminates in its own isolated network segment within the DMZ.

Figure 3-14: Midtown Substation Network Architecture

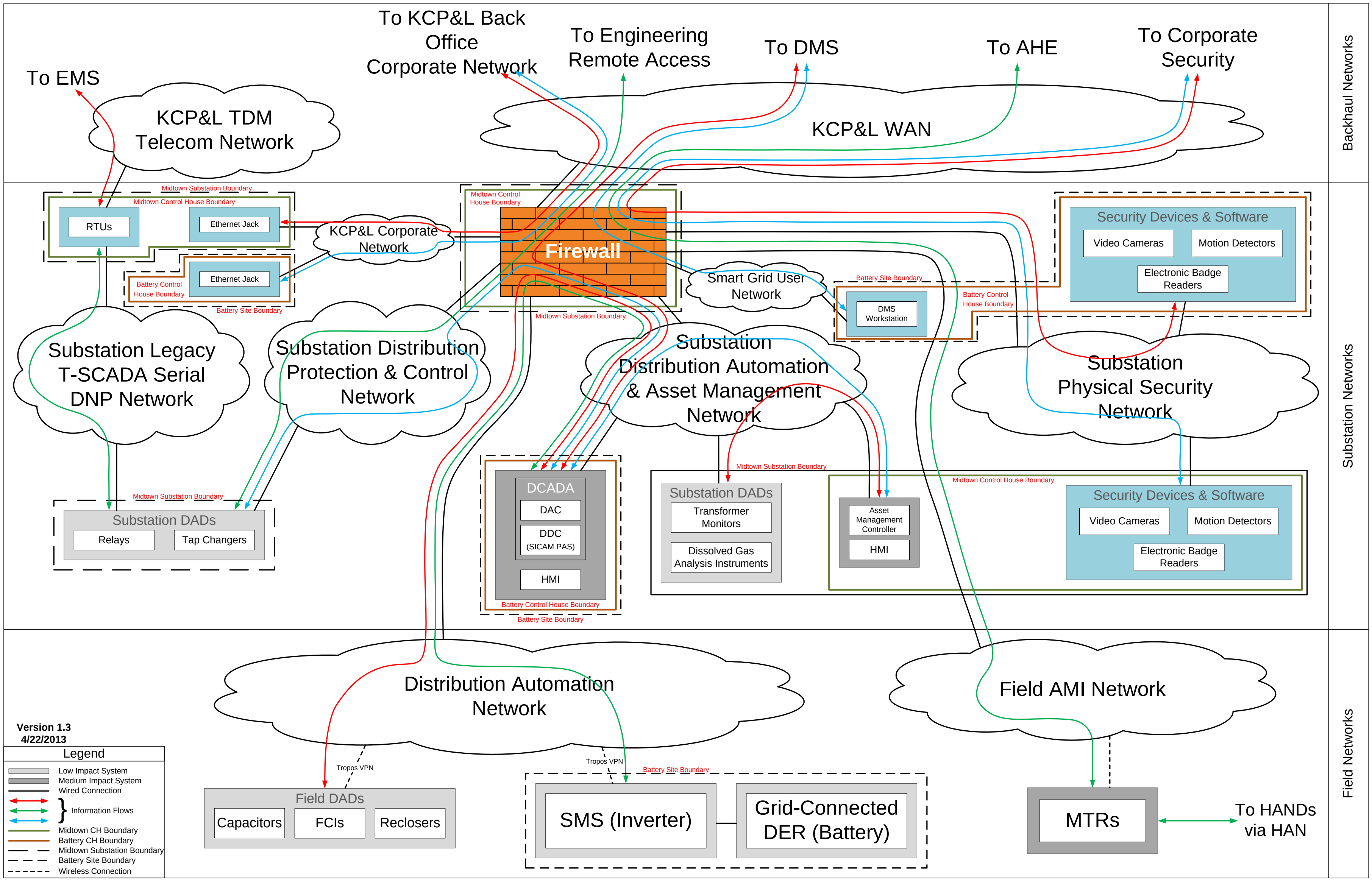


Figure 3-15: Back Office Network Architecture

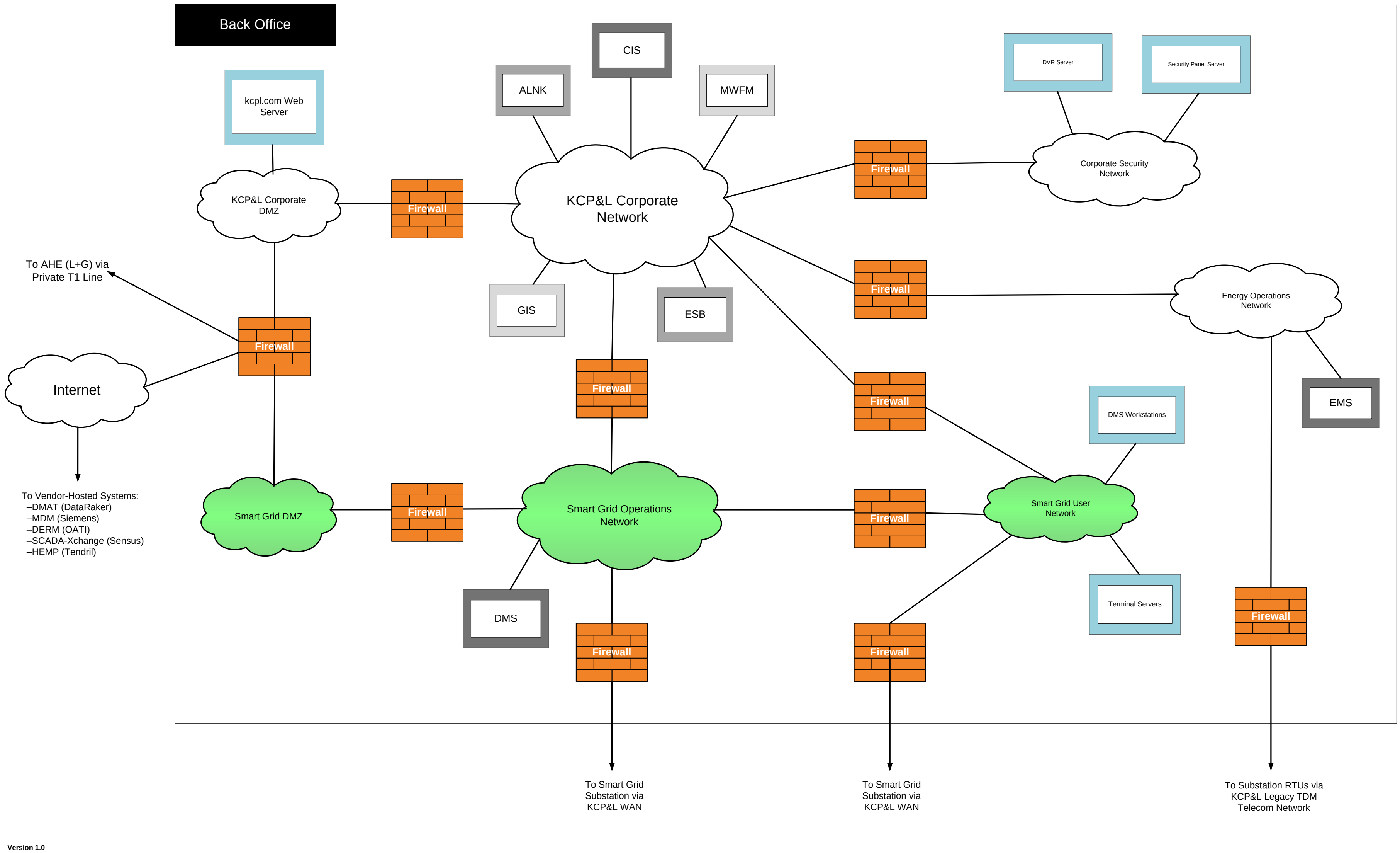
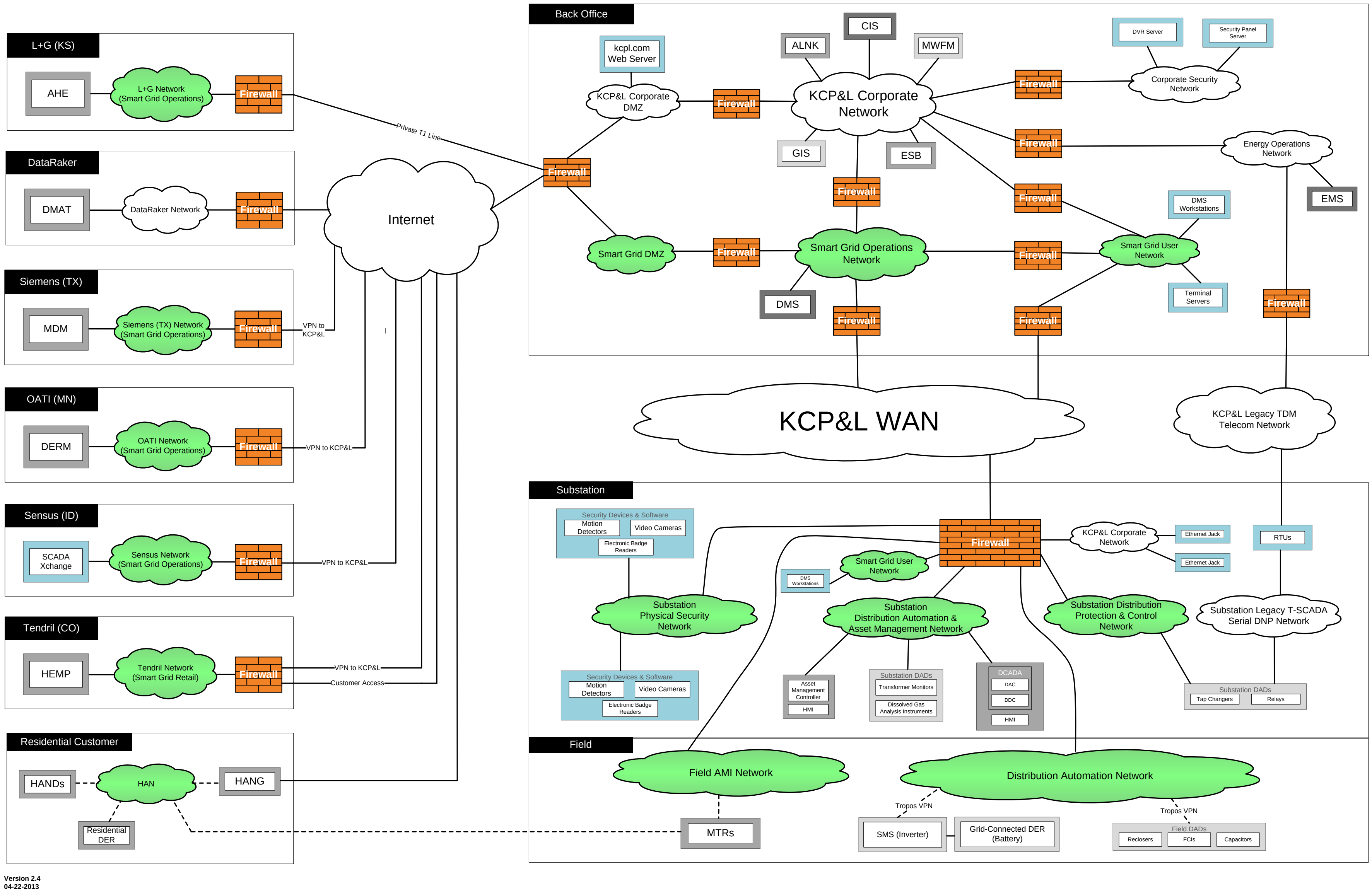


Figure 3-16: Overall SmartGrid Network Architecture



The other networks shown in Figure 3-15 existed prior to the SGDP. However, here is a short description of each:

- KCP&L Corporate DMZ – This network serves as an isolated environment for other enterprise systems that KCP&L prefers to keep off of their internal corporate network for security reasons. One example is KCP&L's corporate website web server. This environment is also utilized to terminate other third-party private connections that fall outside the scope of the SGDP.
- KCP&L Corporate Network – This network serves as KCP&L's primary location for its corporate business applications and most of the legacy systems that have interfaces to the new smart grid systems implemented as part of the SGDP including CIS, MWFM, GIS, and ALNK. Also, most of the corporate workstations that KCP&L personnel use are located on this network.
- Corporate Security Network – This network contains the back office corporate security servers that collect security events from KCP&L's various locations including the SGDP substation.
- Energy Operations Network – This network contains KCP&L's highly critical transmission control system (EMS).

Just like the various network segments within the SGDP substation network architecture, the communication between the newly implemented back office network segments as well as between KCP&L legacy network segments and any smart grid network segment is restricted using firewall rules. Only the minimum ports and services required for necessary message transfer between systems is allowed. In addition, all of the various smart grid network segments were implemented using a unique IP address space managed by KCP&L. Each smart grid network segment was isolated to its own subnet within the unique IP address space. This made it easier to design and implement the various VLANs and to make efficient use of the available pool of IP addresses.

To follow the recommendations provided by UCAIug in their DM Security Profile, KCP&L implemented the smart grid terminal servers contained within the back office Smart Grid User Network. This ensured that any KCP&L user coming from the KCP&L Corporate Network had to first remote to one of the two terminal servers before being able to remote to one of the various smart grid systems. In addition, no Internet access was allowed to or from any of the various smart grid secure enclaves both in the back office and in the substation. Furthermore, to isolate smart grid traffic traveling between KCP&L physical sites from other corporate traffic, the project team utilized VPNs. This allowed KCP&L to utilize the existing KCP&L WAN to transport the information while still adhering to the security requirements of the SGDP.

The final portion of the SGDP network architecture consisted of how the internally-hosted smart grid systems interfaced with vendor-hosted ones (graphically shown in Figure 3-16). To ensure the same level of isolation and security requirements were in place for communication between KCP&L and these vendor -hosted systems, KCP&L implemented VPN connections over the Internet to the following vendors(system hosted shown in parentheses):

- OATI (DERM)
- Sensus (SCADA-Xchange)
- Siemens (MDM)
- Tendril (HEMP)

KCP&L implemented another VPN connection that is not shown on this diagram. It was for access to the DMS Support System hosted by Siemens (a separate division and office location than the Siemens shown hosting the MDM). Most of the VPN connections are monitored and maintained by the corresponding vendor, but there are a couple that are monitored and maintained by KCP&L due to the vendor's inability to do so. As mentioned previously, each of the third-party VPN connections is terminated (on the KCP&L side) in separate, isolated environments represented by the smart grid DMZ cloud in Figure 3-16.

KCP&L utilized the existing private T1 lines to Landis+Gyr to transport communication to and from the AHE, which were managed by a combination of Landis+Gyr and KCP&L. As part of the SGDP, KCP&L implemented and migrated to a new pair of private T1 lines that utilize MPLS (Multi-Protocol Label Switching) and encryption. In addition, the new T1 lines are completely monitored and maintained by Landis+Gyr, which has greatly simplified troubleshooting for any communication issues to or from Landis+Gyr.

KCP&L chose to not implement a VPN to Oracle for communications to DMAT. This was because DMAT was a legacy system and all communication both to and from it consists of file transfers via SFTP. As such, utilizing the Internet for transport was considered acceptable as part of the SGDP.

KCP&L used a combination of external and internal firewalls to restrict communication in and out of the overall KCP&L smart grid network and between the various smart grid network segments both in the back office and in the substation. The external firewalls, managed by one group in KCP&L's IT, are used to restrict communication to and from each vendor-hosted system. The internal firewalls, managed by another group in KCP&L IT, are used to not only restrict communication between KCP&L's Corporate Network and any of the smart grid network segments but also between any two smart grid network segments. Thus, communication between two smart grid systems that reside on separate network segments must traverse at least one layer of firewalls regardless of its physical location.

3.2.7 Cyber Security Verification

The final sub-area within the Implement focus area was performing a cyber security controls verification for one of the vendor-hosted SGDP systems to ensure that guidelines in the NISTIR-7628 have been met. KCP&L chose to perform this verification on Landis+Gyr, the vendor hosting the AHE system. This verification process consisted of four phases:

1. Pre-verification data collection and review
2. Onsite verification
3. Analysis
4. Report generation

Pre-verification data collection and review consisted of sending a data request to Landis+Gyr to furnish the following documentation:

- A detailed list of servers and work stations that are used for hosting the AHE
- A diagram detailing the network topology of the hosted system
- Final responses to previously sent security survey (see Section 3.2.4 for more information about the survey) that included all of the applicable NISTIR-7628 controls
- Copy of internal or third-party audit reports (general IT or cyber security specific) performed for hosted site
- The reports, findings, and action plans of any vulnerability assessment performed within the last twelve calendar months
- A detailed description of implemented physical security controls to secure the hosted site

Landis+Gyr was very cooperative in providing nearly all of the request material prior to the onsite visit. Once the project team received the request documentation, they reviewed and determined that nearly all of the applicable NISTIR-7628 security controls were supported. Only a handful were determined to be either not supported, partially supported, or no longer applicable.

The project team then discussed and prioritized focus areas for the onsite verification visit based upon the following::

- NISTIR-7628 assessment guidelines
- KCP&L SGDP design
- Risk assessment results (see Section 3.2.1 for more information on the risk assessment)
- Lessons learned from NERC CIP audits
- Observations and outcomes of vulnerability assessments

One of the primary goals of the onsite verification was to confirm the feedback that Landis+Gyr provided in their data request. Nearly all of the NISTIR-7628 controls families were discussed, but the ones that were discussed the most included:

- Access Control
- Configuration Management
- Continuity of Operations
- Incident Response
- Media Protection
- Physical and Environmental Security
- Personnel Security

The onsite verification visit consisted of interviewing Landis+Gyr personnel, observing the hosted environment, reviewing documentation, and reviewing evidence for twenty-two areas of cyber security and information technology controls:

1. Hosting services applicable to KCP&L
2. Secure Software Development Life Cycle (SDLC)
3. Security configuration management (Ports and services, Patch management, Malicious software prevention, and Logging, auditing and monitoring)
4. Access/account management
5. Change management
6. Network security architecture
7. Code management
8. Vulnerability and security assessments
9. Electronic access controls and monitoring
10. Physical access controls and monitoring
11. Cyber security incident response process and procedures
12. Data backup and restoration
13. Disaster recovery/continuity of operations
14. Data center operations
15. Information protection
16. Test environment
17. Testing methodology
18. Personnel security and training
19. Cyber security team
20. Leadership commitment/support
21. Internal/third-party audits
22. Industry participation

The onsite verification at Landis+Gyr took place over a period of two days. During those two days, Landis+Gyr provided a panel of security and auditing personnel to provide feedback to the questions that the KCP&L project team had prepared. Depending on the specific topic being discussed, Landis+Gyr brought in other SMEs to provide additional detailed information. Overall, Landis+Gyr was very accommodating and helpful during the entire visit.

In the next phase, KCP&L analyzed the information collected before and during the onsite visit. The analysis focused on determining whether Landis+Gyr's AHE system and hosting practices adhere to the guidelines set forth in the NISTIR-7628 and each of the twenty-two areas identified above. For each of the criteria, KCP&L assessed if Landis+Gyr:

1. Completely adhered to the guidelines
2. Partially adhered to the guidelines (including identification of gaps)
3. Did not adhere to the guidelines

After analyzing, KCP&L generated a report detailing the project team's analysis and identified the security gaps that Landis+Gyr had. Specifically, for each of the NISTIR-7628 controls that were prioritized for the onsite verification and for each of the twenty-two areas of cyber security and information technology controls, the report concluded whether Landis+Gyr's security controls were:

1. Satisfactory
2. Other than Satisfactory

KCP&L found that Landis+Gyr's system and hosting practices satisfied the guidelines for all twenty-two areas of cyber security and information technology controls. Of the applicable NISTIR-7628 security controls, the report concluded that:

- One control was *not supported*
  - AC-11 (Concurrent Session Control)
- One control previously determined to be "partially supported" was assessed to be *fully supported*
  - AC-13 (Remote Session Termination)
- Two controls previously determined to be "not applicable" were assessed to be *fully supported*
  - AU-14 (Security Policy Compliance)
  - SC-30 (Smart Grid Information System Partitioning)
- Two controls were confirmed to be *not applicable*
  - AC-18 (Use of External Information Control Systems)
  - IA-1 (Identification and Authentication Policy and Procedures)
- All other controls were *fully supported*

Landis+Gyr acknowledged that they did not support concurrent session control at the time of the assessment but that they a path to resolution in their future feature enhancement roadmap. Overall, based upon all the data gathered, KCP&L concluded that Landis+Gyr's AHE system and hosting practices were satisfactory.

After KCP&L finalized the report, the project team sent the report to the vendor for review and feedback. Following their review, Landis+Gyr provided feedback that they had since remediated the security gap of not complying with NISTIR-7628 control AC-11. Starting with Command Center version 6.1, the software now supports concurrent session control by allowing administrators to configure whether users may only have one session or multiple sessions open at the same time. Thus, Landis+Gyr is now compliant with all of the NISTIR-7628 security controls that KCP&L found to be applicable to AHE. To view the contents of the full body of the report, please see Appendix O.

3.2.8 Lessons Learned

Throughout the build, integration, and daily operation of the project components, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- Device Firmware Version and Settings Management – KCP&L did not implement a process and/or system for managing configuration settings and firmware versions for devices (meters, field devices, substation devices, etc.) as part of the SGDP. In addition, firmware upgrades were not performed on a routine, scheduled basis. For the most part, upgrades were performed on an as needed basis when additional functionality was needed to support the implementation of certain process flows or when an operational issue and/or bug was discovered.

  To account for this gap, KCP&L is in the process of implementing an ODM (Operational Device Management) system as part of an enterprise MDM deployment project. The ODM will allow KCP&L to centrally manage and maintain meter asset information including attributes, installation information, removal information, configuration groups, firmware updates, test results, and service history. At first, ODM is planned to become the system of record for all meters (not usage information) but can later be utilized to manage other field devices (capacitor banks, FCIs, reclosers, etc.) and substation devices (protection relays, transformer tap changers, etc.). Having all the meter asset information centrally collected will make it easier for KCP&L to maintain the devices, including scheduling and implementing routine firmware upgrades. This will also ensure that all the devices stay more up to date with the latest upgrades and security patches.

- Physical Access Control/Key Management – KCP&L designed and implemented new physical security zones for SmartGrid Innovation Park as part of the SGDP. Physical access control within these zones used a variety of technologies including electronic badge readers, physical keys, video surveillance, intrusion detection, and motion detection (see Section 3.2.5 for more details). On the other hand, physical access control for the distribution devices themselves was implemented in a simpler fashion that consisted of standard, physical keys that were not unique per device. This type of implementation can be very costly to maintain if a large number of locks need to be re-keyed due to lost keys or personnel turnover. It can also be quite challenging to sustain a proper level of security since unauthorized copies of keys can be made without corporate security being aware (no tracking capability).

  As KCP&L progresses with more advanced distribution automation schemes and distribution devices start to become incorporated into security requirements mandated by government entities, KCP&L will need to assess more robust physical security access control for the devices themselves. One possible option would be to deploy an electronic key platform. This would make it much more feasible for each device's enclosure to have a unique key that automatically gets refreshed on a defined interval. In addition, access for personnel would be managed and authorized from a central administrative server, providing KCP&L the ability to quickly modify one or more individuals' access permissions if they are either transferred or terminated. Finally, this type of deployment would provide detailed logging of who accessed what lock at what time and generate additional alerts or alarms to be sent to corporate security, if desired. These capabilities would not only simplify compliance with potential security requirements but also provide a much more secure distribution management environment overall.

- Utility Operational Technology (O/T) Challenges – The deployment and maintenance of the Substation Distribution Protection & Control Network involved collaboration between IT and operations, something that historically has rarely occurred both at KCP&L and across the utility industry. The IP network group (part of IT) worked with both relay technicians and construction & maintenance electricians (part of field operations). This was due to specialized expertise needed for the equipment involved, the location where the equipment was installed, and separation of duties defined between union and non-union personnel. The IP network group was the only team at KCP&L that had the expertise to configure and maintain the IP-based networking switch infrastructure that provided connectivity to all of the Substation DADs. Relay technicians were responsible for configuring and maintaining the Substation DADs themselves, whereas the construction & maintenance electricians were responsible for installing and maintaining the fiber connections that ran between the network switches and the Substation DADs. The SGDP team assisted the network group with conducting network switch training sessions with both operational groups to provide them step-by-step procedures on troubleshooting hardware and/or communication issues that they might find out in the field. Unfortunately, outside the training sessions and the initial installation and commissioning of the network, the operational groups and network group did not typically work directly with each other when communication issues arose. They instead relied on the SGDP team to facilitate interaction if expertise and/or feedback was needed from the other groups.

  If KCP&L decides to expand IP-based communication in their field environments, careful consideration will need to be provided in how support will be handled. If responsibility will remain shared between IT and operational groups, management will need to clearly define roles and responsibilities of each group and build an environment of open collaboration between the teams to ensure a safe, secure, and reliable infrastructure. Cross-training sessions will need to be incorporated into each team's required set of training to ensure that the operational groups have a better understanding of IP-networking basics as well as the layout and functionality of the switching hardware. In addition, the training will need to ensure that the network group is certified to work in or near the switchgear enclosures, as needed, to support the networking hardware.

  Another option would be to create a new, cross-functional support group that has the expertise necessary to bridge the gap for installing, maintaining, and troubleshooting both the networking hardware as well as the Substation DADs that utilize IP-based communication. Members of the new team would handle a majority of the work themselves and work with the existing IT and operational teams for more complex technical issues, as needed.

- Incorporate Security into Procurement Process – Although security was part of the procurement and vendor selection process at the beginning of the SGDP, it was not one of the major deciding factors. A more thorough investigation and analysis of the vendors' solutions and their hosting capabilities was performed as part of the Application Security Assessment and Cyber Security Verification processes (see Sections 3.2.4 and 3.2.7 for more information). These processes provided the SGDP team a great indication of how secure the vendors' practices and solutions were and allowed them to decide whether additional controls needed to be implemented or the associated risk be accepted within the scope of the SGDP. However, some of the areas of focus during the onsite verification should have been handled as part of the procurement process at the beginning of the project. For systems hosted internally to KCP&L, this should include at least access control, configuration management, system/communication protection, and system/information integrity. For systems hosted by a third-party this should additionally include at least continuity of operations, incident response, media protection, and physical security.

Going forward, KCP&L has made strides to improve upon this process. They have started to incorporate the guidelines set forth by the Energy Sector Control Systems Working Group (ESCSWG) in their Cybersecurity Procurement Language for Energy Delivery Systems document. [29] This document was built upon the Cyber Security Procurement Language for Control Systems document, previously published from a joint effort between the DOE and the U.S. Department of Homeland Security (DHS). The ESCSWG document provides a baseline set of procurement language based upon general cyber security considerations in the areas of:

- Software and Services
- Access Control
- Account Management
- Session Management
- Authentication/Password Policy and Management
- Logging and Auditing
- Communication Restrictions
- Malware Detection and Protection
- Heartbeat Signals
- Reliability and Adherence to Standards

The best method of ensuring that a new system is secure throughout its lifecycle is to assess what security controls should be in place within the design phase because it is much easier to bake security into a system from the beginning rather than bolt it on in later phases, which is precisely the primary goal of the ESCSWG document. KCP&L is now including cyber security requirements in their procurement and vendor selection process as part of their large enterprisewide program that consists of several deployment and upgrade projects.

- Security Zones in Substation Field Environment – As part of the SGDP, KCP&L built a SmartGrid-dedicated network that was isolated from the corporate network. Within the SmartGrid network, several isolated segments or security zones were implemented. Most of these zones were located within the SGDP substation and the field environment powered from that substation. The design and architecture of the isolated segments was based upon the security zones that were presented in the cyber security risk assessment performed earlier in the project (see Section 3.2.2.1 for more information) and recommendations from industry guidelines (NISTIR-7628 and UCAIug Security Profiles for AMI and DM). The goal of the segmentation was to group systems and/or devices based upon their criticality level and business function. The security zones that were implemented in the SGDP substation field environment were:
  - Corporate Network – Extension of the back office corporate network
  - Substation Distribution Protection & Control Network – Location of the Substation DADs and zone in which IEC 61850 GOOSE messaging was utilized
  - Smart Grid User Network – Location of DMS Workstation used for user access to the DMS located in a separate SmartGrid security zone in the back office
  - Substation Distribution Automation & Asset Management Network – Location of SmartGrid substation DCADA and its corresponding HMIs

- Substation Physical Security Network – Location of security panel and DVR (Digital Video Recorder) used to collect and analyze data from security devices throughout the substation and backhaul necessary alarms and events to the Corporate Security servers in the back office
- Distribution Automation Network – Location of the Field DADs installed throughout the demonstration zone and the Grid-Connected Battery
- Field AMI Network – Location of the SmartMeters installed at customer premises throughout the demonstration zone

All the systems and/or devices within each zone were allowed to freely communicate with each other. However, any communication that had to traverse between zones was limited to the minimum ports and services necessary for application functionality. This communication was filtered by implementing firewall rules between each of the security zones (see Figure 3-14 for a visual representation of these zones). These new security zones were implemented alongside but isolated from an existing, legacy network comprised of serial-based communication to collect status from the Substation DADs via an RTU and backhaul it to the KCP&L EMS via another legacy network based upon TDM (Time-Division Multiplexing) technology.

By implementing these security zones, KCP&L was able to learn firsthand what level of network segmentation would be necessary to comply with industry standards if they chose to expand IP-based communication and distribution automation technologies to their other distribution substations in the future. In addition, by the time KCP&L would be ready to move forward in this direction, there is a strong possibility that such segmentation would be mandated by government entities (such as NERC) for systems and devices that fall within the distribution system.

An additional item that KCP&L would need to consider down the road is strict segmentation between distribution-level assets and transmission-level assets in the substation, especially if both are upgraded to IP-based communication. This was accomplished on the SGDP because the distribution portions utilized IP-based communication and the transmission portions utilized legacy, non IP-based communication and were thus inherently isolated (different equipment used to collect data and transport it to the back office). However, if both portions were upgraded to IP-based communication in the future, the corresponding assets would have to be in different security zones, isolated from each other. In addition, the backhaul of transmission-level data would have to be isolated from the backhaul of distribution-level data. This could be implemented using logical isolation via virtual separation on shared network hardware or physical isolation via completely separate cabling and network hardware. There would be pros and cons for each type of implementation that KCP&L would have to assess.

3.3 Education & Outreach

KCP&L's approach to public education and outreach for its SGDP took a highly-targeted, multiple-channel approach to reach customers and other key stakeholders. Table 3-5 below identifies key stakeholders and communication methods that were utilized for each audience. Descriptions of the communication methods identified in Table 3-5 are grouped in the following subsections:

- All KCP&L Customers
- SGDP Area Customers
- KCP&L Employees
- State Agencies, Legislators, and Regulators
- Electric Utilities and Smart Grid Industry
- Targeted Education & Outreach Initiatives
- Project Tours and Field Demonstrations

Table 3-5: SmartGrid Audience Communication Methods

Audiences	Audience Description	Communication Methods
All KCP&L Customers	While customers living within the SGDP area will be the first affected by SmartGrid initiatives, what KCP&L learns from the project will eventually impact all KCP&L customers. As such, outreach to the entirety of KCP&L's customer base will be an important part of SmartGrid communications. Key Stakeholders: • Residential Customers • Commercial Customers • Industrial Customers	1. SmartGrid website 2. Project Literature 3. Radio advertising 4. Print advertising 5. Outdoor advertising 6. Energy fairs 7. SmartGrid Demonstration House 8. Social media 9. KC media coverage 10. SmartGrid education module for schools 11. KCP&L employee advocates 12. SmartGrid customer service representatives 13. SmartGrid office
SGDP Area Customers	Customers living within the SGDP Area. Key Stakeholders: • Individual Customers • Neighborhood Groups • Schools • Community Leaders • Elected Officials • Green Impact Zone Partners	1. All Communications Methods to All KCP&L Customers 2. Direct mail 3. SmartGrid welcome kit 4. SmartGrid DVD 5. Email outreach 6. Automated customer notification 7. Key leader briefings and mailings 8. Community organization meetings and newsletters 9. Neighborhood association meetings and newsletters 10. Church group meetings, displays and bulletins 11. Green Impact Zone staff 12. Ambassadors

Audiences	Audience Description	Communication Methods
KCP&L Employees	As media coverage and interest of the project in the broader service territory increases, KCP&L employees will be asked by friends, family and neighbors about SmartGrid. The 3,600 KCP&L employees can be utilized as SmartGrid ambassadors, but KCP&L will need to provide them with ongoing communications in order to make them effective. Key Stakeholders: • Customer Care Departments • Engineering and Operating Departments • KCP&L Employees Living in the Project Demonstration Area	1. The Source (employee newsletter) 2. Daily e-Source updates 3. TV monitors 4. Leadership Link videos 5. Managers Leadership Forum updates
State Agencies, Legislators, and Regulators	The individuals in this audience are charged with representing the community. They include elected or appointed individuals, who are especially sensitive to activities that may affect their constituents. Key Stakeholders: • Missouri Public Service Commission & Staff • Kansas Corporation Commission & Staff • Missouri Office of Public Counsel • Elected officials	1. SmartGrid educational workshops 2. MO & KS Commission Smart Grid staff participation in project workshops 3. MO SmartGrid stakeholder group meetings 4. Project technical reports 5. Project technical website
Electric Utilities and Smart Grid Industry	One of the main goals of this project is to serve as a blueprint for future integrated smart grid demonstrations and implementations throughout the country. In order to do this, KCP&L will need to effectively communicate and share knowledge with other utilities and the smart grid industry as a whole. Key Stakeholders: • Department of Energy • National Energy Technology Laboratory • National Institute of Standards & Technology • Smart Grid Interoperability Panel • Professional Associations • Labor Organizations	1. Project technical reports 2. Project technical website 3. EPRI's Smart Grid resource center *(www.smartgrid.epri.com)* 4. Workshops 5. Webcasts 6. Periodic publications 7. White papers/articles 8. SmartGrid Demonstration House 9. SmartSubstation Tour

Samples of all materials produced by the various education and outreach initiatives discussed in the following sections are provided in Appendix P.

3.3.1 All KCP&L Customers

Communicating with KCP&L's end users, both those located in the SGDP area and those in the greater service area, was extremely important. By reaching out to the consumer, KCP&L worked to drive awareness and understanding of SmartGrid as well as encourage product acceptance and adoption.

3.3.1.1 Customer Focused SmartGrid Website

Although internet access is low in some parts of the SGDP area, the KCP&L SmartGrid website was an important customer communication vehicle, both for KCP&L customers within the project area and in the broader service territory. The website provided key information about the SGDP, including facts sheets, meter installation maps, timelines, upcoming events, news and FAQs. The MySmart Portal, MySmart Display, and MySmart Thermostat informational videos were also hosted on the website. The site is part of KCPL.com, but is also accessible via *www.kcplsmartgrid.com*. Figure 3-17 is a screenshot of the original www.kcplsmartgrid.com home page.

Figure 3-17: Original *www.kcplsmartgrid.com* Home Page Screenshot

Over the course of the SGDP, KCP&L continued to add to and enhance the site with user functionality, Flash-enabled graphics, video clips, testimonials, a series of short "How To" videos and project content of broader industry interest. A screenshot of the current www.kcplsmartgrid.com home page is provided in Figure 3-18. Much of the website content is derived from the education and outreach material presented in the following subsections.

Figure 3-18: Current *www.kcplsmartgrid.com* Home Page

3.3.1.2 Project Literature

KCP&L's community and public affairs professionals developed a series of project overview documents that were used throughout all phases of the project to communicate general awareness and understanding of KCP&L's SGDP. Table 3-6 provides a listing of this literature along with the reference to the document image in Appendix P.

Table 3-6: SmartGrid Demonstration Project Information Literature

Title	Appendix
SmartGrid – An initiative to benefit our customers and the communities we serve (with map)	P.1.1.1
SmartGrid – An initiative to benefit our customers and the communities we serve	P.1.1.2
SmartGrid demonstration fact sheet	P.1.1.3
SmartGrid demonstration project timeline	P.1.1.4
SmartGrid demonstration map	P.1.1.5
SmartGrid demonstration Q & A	P.1.1.6
Current partners & vendors	P.1.1.7
SmartGrid Overview	P.1.1.8
SmartGrid Demonstration Q & A	P.1.1.9
SmartGrid Demonstration Fact Sheet	P.1.1.10
SmartGrid Demonstration (component map)	P.1.1.11
SmartGrid Demonstration Map (w/Green Impact Zone)	P.1.1.12
SmartGrid Demonstration Map (w/Green Blue Boundaries)	P.1.1.13
SmartGrid Demonstration Pilot Program	P.1.1.14
Demonstration Project Overview	P.1.1.15
Message Map	P.1.1.16
Talking Points	P.1.1.17
FAQs from Website	P.1.1.18
SmartGrid Solar	P.1.1.19
SmartSolar	P.1.1.20

3.3.1.3 Advertising

Paid advertising represents an important part of KCP&L's public education and outreach efforts, but the geographic boundaries of the SGDP area presented some unique challenges. Paid advertising effectiveness and impact is a derivative of layering multiple avenues, building a reach of at least 70 percent, while still maintaining a healthy frequency of at least 4x. In order to achieve the necessary reach and frequency, KCP&L utilized a combination of radio, print and outdoor advertising.

- Radio – Due to the diverse age range of the SGDP customers, it was important to use a medium that is high reaching. Radio is the second highest reaching medium available (after TV) and is also one of the most cost-effective mediums.
- Print – Despite the overall decrease in physical newspaper consumption, smaller, more-niche community papers (like those read in and around the SGDP area) continue to hold their base as their traditionally older readership is less likely to consume their news online. Additionally, print offers a higher retention rate than radio, allowing KCP&L's message to resonate with customers without the requirement of higher frequencies.
- Outdoor – Urban environments like the SGDP area are ideal settings for outdoor advertising. Even though population density is higher, residents are still very mobile—walking, driving and taking public transportation on a daily basis. This is also a medium that has a much wider mass-market focus. By placing billboards in and around the SGDP area, KCP&L was able to cover a broader customer base.

Table 3-7: Paid Advertising Initiatives

Initiative	Date	Appendix
23 SmartGrid Billboards in Demonstration Project Area	June-Dec. 2012	P.1.2.1
KCATA Bus SmartGrid Signage	June-Dec. 2012	P.1.2.2
Kansas City Star Newspaper Ads	June-Dec. 2012	P.1.2.3
SmartGrid Innovation Park Battery Wrap	2012-Present	P.1.2.4

3.3.1.4 Energy Fairs

In addition to utilizing existing neighborhood and community meetings, KCP&L hosted a series of energy fairs in the SGDP area. These educational events served as training workshops for those customers interested in learning more about SmartGrid, specifically the MySmart suite of products. They were also an ideal opportunity for KCP&L to get anecdotal feedback via one-on-one interaction with customers. The schedule of energy fairs was included in the welcome kits delivered to customers upon meter installation and was also listed on the website. In addition, KCP&L placed automated calls to customers who received their new SmartMeter, notifying them of upcoming energy fairs.

Table 3-8: Schedule of Energy Fairs

Location	Date	Attendance
Missouri Department of Conservation Discovery Center	Nov. 02, 2010	25
Paseo High School	Nov. 06, 2010	400
St. James United Methodist Church	Nov. 18, 2010	50
Paseo High School	Dec.0 4, 2010	200
Missouri Department of Conservation Discovery Center	Jan. 15, 2011	Unknown

3.3.1.5 Social Media

Evidence points to significant use of mobile phones in the SGDP area, making a social media strategy important to the overall public education and outreach effort as the SGDP progressed. Texting, Twitter, YouTube, etc., informed residents about upcoming events, ways to increase energy efficiency and other important SmartGrid information. Table 3-9 contains a listing of the project videos that are available on YouTube. A mobile platform allowed real-time notification of installation appointments, completions and other notifications, improving the overall customer experience. Subsequently, KCP&L was able to engage in a two-way dialogue with customers and receive instant feedback on customer reaction/sentiment. The SGDP social media strategy was balanced against KCP&L's larger communications efforts and was conducted in coordination with the company's broader social media strategy and rollout.

Table 3-9: YouTube Videos

Title	Date Uploaded	Link
KCP&L SmartGrid	Mar. 28, 2011	https://www.youtube.com/watch?v=I9K10K0nt_Q
KCP&L/EPRI Smart Grid Demonstration	Oct. 19, 2011	https://www.youtube.com/watch?v=kXc6c_I1wOU
MySmart Display	Sept. 14, 2012	https://www.youtube.com/watch?v=8v80dkvs_eA
MySmart Portal	Sept. 14, 2012	https://www.youtube.com/watch?v=AtW6adt6UNM
MySmart Thermostat	Sept. 14, 2012	https://www.youtube.com/watch?v=9AOHaUhHPsU
Save by wrapping your hot water heater	Sept. 24, 2012	https://www.youtube.com/watch?v=ZLvzoiGgyrE
KCP&L My Smart Display from Tendril	Nov. 20, 2012	https://www.youtube.com/watch?v=ZXaF1xd68CQ
KCP&L Smart Portal	Nov. 20, 2012	https://www.youtube.com/watch?v=aEWtU4jm1z4

3.3.1.6 Kansas City Media Briefings

Although smart grid initiatives have been rolled out in other parts of the country, KCP&L's SGDP was the first to introduce these technologies to an urban core. As such, it attracted significant local media attention. Local media targets in the Kansas City area include *The Kansas City Star, Kansas City Business Journal, The Call, The Globe*, KMBZ 980 AM, KCUR 89.3 FM, WDAF-4, KSHB-41, KCTV-5 and KMBC-9. KCP&L had a set of statements prepared to respond to general media inquiries regarding SmartGrid. In addition, KCP&L identified a number of short- and long-term project milestones that served as opportunities for proactive media outreach. For example, on November 1, 2010, KCP&L conducted a SmartGrid media day featuring demonstrations of the MySmart suite of products. Figure 3-19 contains a representative news story resulting from the SmartGrid media day.

Figure 3-19: SmartGrid News Story

Home | News | Weather | Traffic | Sports | Entertainment | Mornings | Health | Contests | Deals | Contact

FOX 4 Video | Local News | Offbeat | Politics | Business | Nat'l & World News | Problem Solvers | Reaching 4 Excellence | Obituaries

QUICK LINKS | Christmas | Scared of Santa | Lunar Eclipse | Spiderman Fail | Slippery Pile-Up | Your Weather Photos | Military Greetings

New Smart Technology to Save KCP&L Customers Money

Web Staff
12:44 p.m. CST, November 10, 2010

Kan — Kansas City Power and Light has begun a new $48 million project designed to help customers learn to cut energy costs by giving them real-time information on energy usage. It's called the Smartgrid Project.

It's a five-year pilot program that will install new smart technology in certain houses in the midtown and urban core areas. It's paid for by a $24 million grant by the Department of Energy.

According to KCP&L, 14,000 customers will receive new smart meters and new smart thermometers at no cost. Customer houses will be upgraded at no cost and the advantages will be improved service, reliability and it will reduce outages and lower energy bills.

The new smart technology will allow consumers to keep an eye on bills daily. For example, if a person vacuums their home, they can check the smart display afterward to see how much the energy usage cost.

KCP&L have configured a house on Emanuel Cleaver II Blvd. and Troost for a model demonstration. When it's ready, a student from the University of Missouri Kansas City will live upstairs as a docent.

Topics
Missouri

Pictures: Dollyland At Christmas
Pictures: Abominable Snowmen
Ice Carving Demo on the Plaza
Humane Society Photos with Santa

Table 3-10: Kansas City Media Initiatives

Initiative	Outlet	Date	Appendix
The Green Impact Zone	Under the Clock: The GIZ Blog	Mar. 27, 2009	P.1.3.1
KCP&L Smart Grid Places Customer in Control	Examiner.com	June 22, 2009	P.1.3.2
Details on GIZ are Sparse So Far	Kansas City Star	July 3, 2009	P.1.3.3
A Golden Opportunity for KC's Green Zone	Kansas City Star	Aug. 31, 2009	P.1.3.4
Green Impact Zone Funds Already in Use in Metro	Fox 4 KC	Sept. 1, 2009	P.1.3.5
Kansas City Power & Light Commits $14M for Smart Grid Technology	Kansas City Business Journal	Sept. 1, 2009	P.1.3.6
Federal Officials Praise GIZ in KC's Urban Core	Kansas City Star	Sept. 1, 2009	P.1.3.7
Green Impact Zone Waits for New Pot of Smart Grid Funds	Kansas City Star	Oct. 27, 2009	P.1.3.8
GIZ Getting Off to Slow Start	Fox 4 KC	Nov. 19, 2009	P.1.3.9
KCP&L to Receive Stimulus Grant for Kansas City SmartGrid Demonstration	Press Conference	Nov. 24, 2009	- - -
KCP&L to Receive Stimulus Grant for Kansas City SmartGrid Demonstration	Press Release	Nov. 24, 2009	P.1.3.10
KC's Electric Efficiency Get $24 Million Boost	Kansas City Star	Nov. 24, 2009	P.1.3.11
KCP&L will Get $24M In Stimulus Money	Kansas City Business Journal	Nov. 24, 2009	P.1.3.12
$24-Million Federal Grant Powers Smart Grid Plan	KCUR.org	Nov. 24, 2009	P.1.3.13
GIZ Report is Delayed	Kansas City Star	Dec. 1, 2009	P.1.3.14
An Innovative Step Toward Smarter Energy Use	Kansas City Star	Dec. 20, 2009	P.1.3.15
Stimulus Puts U.S. Renewable Energy Generation on Track to Double by 2012	Kansas City Business Journal	Dec. 21, 2009	P.1.3.16
SmartGrid Demonstration Project	MARC Annual Report Update	2010	P.1.3.17
New KCP&L SmartGrid Customer Programs Begin	MARC Newsletter	Oct. 2010	P.1.3.18
Old Home Provides Tips on Efficiency	News-PressNow.com	Oct. 2, 2010	P.1.3.19
KCP&L Launches SmartGrid Project	Press Release	Nov. 10, 2010	P.1.3.20
New Smart Technology to Save KCP&L Customers Money	Fox 4 KC	Nov. 10, 2010	P.1.3.21
Green Impact Zone: Putting Funds to Work	KCB Central	Nov. 2010	P.1.3.22
Kansas City Power & Light Meters Out Sustainability Effort	Kansas City Business Journal	Nov. 24, 2010	P.1.3.23
SmartGrid Project Update	MARC newsletter	Jan. 2011	P.1.3.24
Episode 2: Energy Efficiency and Conservation – In-Studio Interview with Kevin Bryant	KCPT – Imagine KC	Jan. 27, 2011	
KCP&L Completes Smart Meter Installation	Press Release	April 29, 2011	P.1.3.25
Growing Jobs in KC's Green Impact Zone	Kansas City Star	June 14-15, 2011	P.1.3.26
KCP&L Announces Solar Project in GIZ	Press Release	Oct. 28, 2011	P.1.3.27
Largest Solar Energy System in Kansas City Area Will Be Installed At Paseo Academy	KSHB	Oct. 28, 2011	P.1.3.28
Green Impact Zone Makes A Small Impact So Far in KC	Kansas City Star	Dec. 3, 2011	P.1.3.29
Green Impact Zone of Missouri	MARC Publication	Sept. 2012	P.1.3.30
KCP&L Officially Opens SmartGrid Innovation Park	Press Release	Oct. 12, 2012	P.1.3.31
KCP&L's Big Battery Aims To Help Spark Midtown Resurgence	KCUR	Oct. 12, 2012	P.1.3.32

3.3.2 SmartGrid Demonstration Project Area Customers

Communicating with KCP&L's end users, both those located in the SGDP area and those in the greater service area, was extremely important. By reaching out to the consumer, KCP&L drove awareness and understanding of SmartGrid as well as encouraged product acceptance and adoption.

3.3.2.1 Direct Mail

One of the challenges of the SGDP area is the high percentage of renters, making it a highly transient area, with residents constantly moving in and out. In addition to the broader mix of marketing and education efforts, KCP&L reached out to residents through a series of direct mail letters and postcards. These consistent and regular updates were particularly useful to new residents within the SGDP area, especially those not already familiar with the project.

In early September 2010, all 14,000 KCP&L customers were sent a letter from Mike Deggendorf, KCP&L's Senior Vice President for Delivery. The letter welcomed them to the SGDP and broadly explained both the customer benefits and next steps as the project got underway.

KCP&L also distributed a series of SmartGrid postcards to customers, staged to coincide with the meter installation schedule.

Table 3-11: Direct Mail Communications

Description	Audience	Date	Appendix
Key Leaders Letter	Key Leaders	Aug. 31, 2010	P.2.1.1
Welcome to SmartGrid Letter	All SGDP Customers	Sept. 2010	P.2.1.2
SmartGrid Postcard	Residential and Commercial Customers	1 Month prior to meter install	P.2.1.3
SmartGrid Meter Installation Postcard	All SGDP Customers	1 Month prior to meter install	P.2.1.4
Key Leaders Update Letter	Key Leaders	January 2011	P.2.1.5
MySmart Products Now What? Postcard	All SGDP Customers	After meter install	P.6.1.4
MySmart Products Interloop Mailer	All SGDP Customers	January 2011	P.6.1.7
MySmart Portal Postcard	All SGDP Customers	February 2011	P.6.1.9
MySmart Display Letter	All SGDP Customers	February 2011	P.6.1.11
MySmart Display Postcard	MySmart Display Customers	February 2011	P.6.1.12
MySmart Display Gift Card Offer Postcard	MySmart Display Customers	March 2011	P.6.1.13
Demo Home Open House Invitation	All SGDP Customers	April 2011	P.6.2.3
"Get Smarter" WebKey Teaser	All SGDP Customers	2011	P.2.1.6
"Get Smarter" WebKey Mailer	All SGDP Customers	2011	P.2.1.7
MySmart Product Letter	New SGDP Customers	2012	P.2.1.8
MySmart Time-of-Use Rates Letter	All SGDP Customers	May 2012	P.2.1.9
You & Sustainability	All SGDP Customers		P.2.1.10
TOU Renew for 2013 Letter	TOU Customers	May 2013	P.2.1.11
TOU Renew for 2014 Letter	TOU Customers	May 2014	P.2.1.12
Demand Response Letters	All MySmart HAN and MySmart Thermostat Customers	May 2014	P.2.1.13
MySmart Display Drop Off Postcard	MySmart Display Customers	October 2014	P.6.1.14

3.3.2.2 SmartGrid Welcome Kit

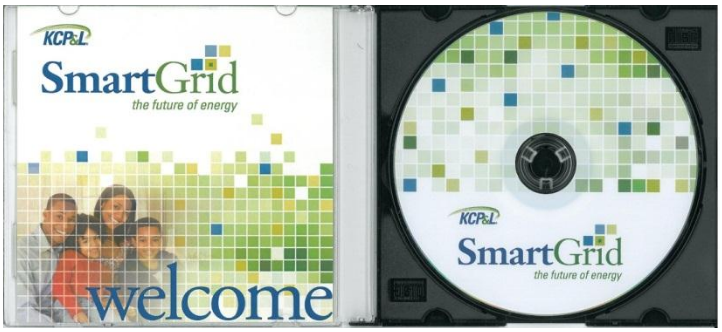
For most customers, meter installation represented the first interaction with the SGDP. At the time of SmartMeter installation, customers were provided with a KCP&L SGDP welcome kit. Included in the welcome kit was a welcome book, MySmart product information, a SmartGrid DVD, information on community weatherization and energy assistance resources, a schedule of upcoming energy fairs and a compact fluorescent light bulb. Appendix P.2.2 contains examples of the kit contents. The welcome kits were either given directly to the customer or left at the front door if no one was available.

Figure 3-20: SmartGrid Welcome Kit

3.3.2.3 SmartGrid DVD

Working with a local Women's Business Enterprise (WBE) video production company, KCP&L developed an overview video that creates general awareness and understanding of KCP&L's SGDP and the customer benefits. Featured on the video are Mike Chesser, CEO of KCP&L; U.S. Rep. Emanuel Cleaver, II, Congressman for Missouri's 5th District; and Margaret May, Executive Director of the Ivanhoe Neighborhood Council. In addition, KCP&L worked with Tendril to develop two short instructional videos for MySmart Display and MySmart Portal, which are included as chapters on the DVD. The video is also available online at www.youtube.com/watch?v=I9K10K0nt_Q.

Figure 3-21: SmartGrid DVD



3.3.2.4 Email Outreach

KCP&L already has a well-established online service for its customers called AccountLink. Through AccountLink, customers can access their account information and billing history, and make payments online. There are already more than 2,800 AccountLink customers within the SGDP area. With access to these customers' email addresses, KCP&L was able to distribute targeted emails to customers who already used and were familiar with the company's online platform. The remainder of the KCP&L customers were required to register for AccountLink the first time they signed on to MySmart Portal to view their usage information. As more customers were acquired and product adoption increased, more of the public education and outreach was conducted online via email.

Table 3-12: Email Communications

Description	Audience	Date	Appendix
MySmart Portal – Launch Notification	All SmartGrid Customers	2011	P.2.3.1
Get Smarter About Energy – Time-of-Use Program	All SmartGrid Customers	2012	P.2.3.2
Time-of-Use Rates Letter	All SmartGrid Customers	2012	P.2.3.3
Your "Get Smarter" Guide – MySmart Home Offering	SmartGrid Energy Optimizer Customers	2012	P.2.3.4
Your "Get Smarter" Guide – Time-of-Use Offering	All SmartGrid Customers	2012	P.2.3.5
Your "Get Smarter" Guide – KCP&L SmartGrid Q&A	All SmartGrid Customers	2012	P.2.3.6
Your "Get Smarter" Guide – MySmart Home and MySmart Portal Information	All SmartGrid Customers	2012	P.2.3.7
Your "Get Smarter" Guide – KCP&L SmartGrid Fall Events	All SmartGrid Customers	2012	P.2.3.8
Your "Get Smarter" Guide – MySmart Portal Makeover	All SmartGrid Customers	2012	P.2.3.9
Your "Get Smarter" Guide – MySmart Program Information	All SmartGrid Customers	2012	P.2.3.10
Your "Get Smarter" Guide – MySmart Portal Can Help Keep Your Home Toasty and You Penny-wise!	All SmartGrid Customers	2012	P.2.3.11
Your "Get Smarter" Guide – Drop-Off MySmart Home Devices and Pick-up CFL Light Bulbs	All SmartGrid Customers	2014	P.2.3.12

3.3.2.5 Automated Customer Notification

KCP&L has had great success reaching customers for its Connections Program (energy efficiency and bill payment assistance) through the use of automated customer notification calls. These calls allow KCP&L to reach a large number of customers in a relatively short amount of time and at a low cost. In particular, KCP&L used automated calls to drive attendance to upcoming energy fairs, where members of the SmartGrid team provided an overview of the project as well as training on the MySmart suite of products.

3.3.2.6 Civic Outreach

A number of formal and informal community groups exist within the SGDP area. KCP&L made efforts to engage in frequent communication with these groups to gather project feedback and communicate messages back to the end users.

3.3.2.6.1 Key Leaders

Critical to the success of the SGDP public education and outreach effort was the endorsement and support of key community and neighborhood leaders. KCP&L partnered with community leaders within the SGDP area to raise awareness of SmartGrid and other KCP&L initiatives, particularly the company's energy efficiency products and services. On September 14, 2010, KCP&L hosted about 40 key leaders at a SmartGrid briefing at the Green Impact Zone offices. This meeting was an opportunity to exchange information, answer questions and proactively address any concerns. This event was preceded by a letter that was mailed to approximately 150 community leaders providing them an update on the project. Continued, frequent, thorough two-way communication with key leaders over the course of the SGDP allowed them to become effective ambassadors for KCP&L, built support for SmartGrid initiatives and eased any community concerns that may have arisen. KCP&L's Government Affairs department managed direct communications with key leaders and elected officials.

Table 3-13: Key Leader Communications

Event	Location	Date	Attendance
Introduction to SmartGrid Demonstration Project	Mid America Regional Council Office	Aug. 17, 2009	
Mid-America Regulatory Conference Tour	Neighborhood & Project Living Proof	June 08, 2010	~50
June Community Event	Swope Parkway	June 12, 2010	1500
MPSC Training	Jefferson City, MO	July 23, 2010	10
Key Leader Community Briefing	GIZ HQ	Sept. 14, 2010	40
Community Leader SmartGrid Event	Project Living Proof	March 10, 2011	35
South Kansas City Chamber of Commerce Tour of Project Living Proof	Project Living Proof	April 27, 2011	15

3.3.2.6.2 Community Organizations

A number of credible, well-established community organizations operate in and around the SGDP area. Key organizations include Brush Creek Community Partners, Blue Hills Community Services, the Southtown Council and Swope Community Builders. These organizations have long-standing relationships with residents in the Green Impact Zone and beyond and were effective partners in educating residents and engaging them in SmartGrid initiatives. KCP&L Community Relations worked closely with these organizations and engaged community leaders via one-on-one communication. These organizations were also utilized to help spread information about the SGDP at their regular meetings and through their organizational newsletters.

Table 3-14: Community Events

Event	Location	Date	Attendance
Halloweatherization	GIZ Office	Oct. 30, 2010	300
SmartGrid Energy Resource Fair	Discovery Center	Nov. 02, 2010	25
SmartGrid Energy Resource Fair	Paseo High School	Nov. 06, 2010	400
SmartGrid Energy Resource Fair	St. James UMC	Nov. 18, 2010	50
SmartGrid Energy Resource Fair	Paseo High School	Dec. 04, 2010	200
Day of Sharing	Project Living Proof	Jan. 06, 2010	20
SmartGrid Energy Resource Fair	Discovery Center	Jan. 15, 2011	Unknown
MySmart Display Customer Engagement Dinner	GIZ Office	Mar. 24, 2011	15
South Kansas City Chamber of Commerce Tour of Project Living Proof	Project Living Proof	April 27, 2011	15
Demonstration Home Grand Opening	Project Living Proof	April 30, 2011	250
Heartland Connection		Jan. 26, 2012	25
Meet Me At The Bridge	48th and Troost Bridge	May 5, 2012	250
Night Out Against Crime	Swope Park	Aug. 7, 2012	300
Innovation Park Ribbon Cutting	Innovation Park	Oct. 12, 2012	100
Halloween Open House	Project Living Proof	Oct. 31, 2012	75

3.3.2.6.3 Neighborhood Associations

Neighborhood associations are critical to Green Impact Zone initiatives. Their engagement in the SGDP lent credibility and granted access to an established communication infrastructure. KCP&L worked closely with neighborhood organizations within the SGDP area to build advocates and cultivate positive relationships in support of the SGDP. Members of KCP&L's Community Relations team met with neighborhood associations regularly throughout the project. In addition to providing an overview of the SGDP, these meetings allowed KCP&L to demonstrate the MySmart suite of products and speak directly to the customer benefits. KCP&L maintained ongoing communication with neighborhood associations throughout the course of the SGDP.

Table 3-15: Schedule of Neighborhood Meetings

Neighborhood	Location	Date	Attendance
Town Fork Creek	Mazuma Credit Union	Sept. 25, 2010	30
Troostwood	Coffee Break	Oct. 02, 2010	8
Manheim Park	Immanuel Lutheran Church	Oct. 09, 2010	9
Squier Park	DeLaSalle High School	Oct. 19, 2010	10
Ivanhoe	Ivanhoe Neighborhood Council	Oct. 23, 2010	85
Blue Hills	Blue Hills Neighborhood Assn.	Oct. 23, 2010	80
49/63	Rockhurst Community Center	Oct. 26, 2010	
Oak Park	Brush Creek Community Center	Oct. 28, 2010	
Brush Creek Community Partners	Midwest Research Institute	Nov. 05, 2010	20
Crestwood	Board Member Home	Nov. 09, 2010	
Rockhill Homes	Board Member Home	Nov. 09, 2010	
Country Side	Minsky's	Nov. 09, 2010	
Hyde Park	Central Presbyterian Church	Nov. 16, 2010	
Ivanhoe	Ivanhoe Neighborhood Council	Feb. 25, 2012	30
Brush Creek Community Partners	SmartGrid Demonstration House	May 21, 2013	

3.3.2.6.4 Faith Communities
The primary churches in the SGDP area represent important community hubs. KCP&L worked with these churches to educate their membership about SmartGrid initiatives to build awareness and encourage participation in the project. A designated KCP&L liaison worked with the large churches within the SGDP area to communicate recent news and to educate leaders and residents about the project's components and benefits. In addition, KCP&L developed content appropriate for church displays and for publication in church bulletins.

3.3.2.6.5 Schools
The Green Impact Zone is home to three schools, and there are several more in the broader SGDP area. Schools are excellent communication/education vehicles for both children and parents. In addition to engaging students, school-based outreach reached parents, grandparents, neighbors, etc. and built a stronger sense of community around the SGDP area. Students were able to assist in making energy improvements while learning about the benefits of energy efficiency.

Table 3-16: Schedule of School Events

School	Event	Date
Paseo High School	You & Sustainability	Dec. 04, 2010
Martin City Middle School	Project Living Proof Tour	June 03, 2011
Paseo High School	Information Session and Tour	Feb. 17, 2012
Grandview High School	Project Living Proof Tour	Nov. 07, 2012
Paseo High School	MySmart Solar Kick-off	Nov. 19, 2012
Paseo High School/UMKC	Project Living Proof Tour	Nov. 19, 2012
Paseo High School	MySmartSolar.edu Workshop	Nov. 19, 2012
Paseo High School	MySmartSolar.edu Project Presentations & Awards	March 20, 2013

KCP&L worked with the Kansas City, Missouri School District, The Paseo Academy of Fine and Performing Arts (Paseo) and University of Missouri- Kansas City (UMKC) to create a curriculum module (MySmartSolar.edu) to teach students about the smart grid, and its role in energy and energy efficiency. Paseo students were given the opportunity to explore energy and the potential capabilities that the alternative sources of energy have to offer. Over the course of several weeks students were tasked with creating a project (report and presentation) focusing on different real life applications in the use of energy efficiency and solar energy. More information about the MySmartSolar.edu program is contained in Appendix P.2.4

3.3.2.7 Consumer Advocate Interaction

Throughout the KCP&L SGDP implementation, a number of paid and unpaid advocates were utilized to help spread information to the consumer.

1.1.1.1.1 KCP&L Employees

With the SGDP, KCP&L had the unique opportunity to utilize the company's 3,600 employees as SmartGrid ambassadors. As media coverage and interest of the project in the broader service territory increased, employees were asked by friends, family and neighbors about SmartGrid. Starting in 2010 and continuing throughout the project, KCP&L made SGDP updates a priority for internal employee communications. The project has been prominently featured in the employee newsletter, The Source, as well as in the daily e-Source updates, Leadership Link videos and at the managers Leadership Forum. In addition, KCP&L has a number of employees who live within the SGDP area. These employees were contacted about being vocal advocates for the SGDP within their neighborhoods. KCP&L created an employee volunteer program specifically for the SGDP to enhance education, promote programs, install products, weatherize homes, etc. These efforts demonstrated KCP&L's commitment to the Green Impact Zone and its residents in a highly visible manner.

1.1.1.1.2 Green Impact Zone Staff

Much of the person-to-person interaction with residents occurred through the staff of the Green Impact Zone. KCP&L's project outreach coordinator managed these relationships to ensure that the Green Impact Zone team had the latest information about SmartGrid initiatives and was prepared to answer questions or to direct customers to additional KCP&L resources. In addition, KCP&L provided ongoing training to Green Impact Zone ambassadors about SmartGrid and maintained regular communication to ensure that education and outreach goals were achieved.

1.1.1.1.3 Ambassadors

In addition to the Green Impact Zone staff, much of the direct customer interaction within the Green Impact Zone portion of the SGDP area occurred through community organizers known as ambassadors. Residents of the Green Impact Zone were recruited to be ambassadors and served as project spokespeople responsible for increasing awareness of SmartGrid and its benefits. They served as a resource for residents by providing them with information and updates on the SGDP. KCP&L worked with the Green Impact Zone to recruit and train ambassadors and had on-going interaction to ensure education and outreach goals were achieved.

1.1.1.1.4 SmartGrid Office

In addition to all of the integrated ongoing channels outlined as part of the public education and outreach efforts, KCP&L wanted to be able to interact face-to-face with customers on a daily basis within the SGDP area. KCP&L established a SmartGrid office within the Green Impact Zone offices at 4600 Paseo. In addition to greater customer interaction, having a KCP&L office staffed by SmartGrid team members within the Green Impact Zone strengthened communication with the Green Impact Zone team.

1.1.1.1.5 SmartGrid Customer Service Representatives

KCP&L hired and trained three dedicated customer service representatives to serve as the SmartGrid support team. These individuals were the first point of contact for customers who have questions, need additional information or want to sign up for SmartGrid products/services. In addition, having a dedicated team improved continuity and message consistency. The SmartGrid support team could be reached via dedicated phone numbers and a dedicated email address.

3.3.3 KCP&L Employees

The project team utilized various forms of internal communication to educate KCP&L employees about the SGDP and keep them informed about its progress.

3.3.3.1 Employee Newsletter (The Source)

The Source is a newsletter published for employees and retirees. The publication features articles about the company and its employees that foster a culture of collaboration, reinforce the values of the Guiding Principles, increase employee engagement, educate employees about company projects and initiatives and provide information that helps employees perform better at their jobs. It is distributed on a monthly basis. The SGDP was featured in The Source on several occasions, as shown in Table 3-17.

Table 3-17: The Source Articles

Initiative	Date	Appendix
This Grant Will Help Map Our Future	Dec 2009	P.3.1.1
KCP&L's SmartGrid Update	May 2010	P.3.1.2
KCP&L's SmartGrid	July/Aug 2010	P.3.1.3
New KCP&L SmartGrid Customer Program Launches	Oct 2010	P.3.1.4
Smart Answers to SmartGrid Questions	Nov 2010	P.3.1.5
Employees Keep SmartGrid On Track	March 2012	P.3.1.6
Our "Top-To-Bottom" SmartGrid Model Leads The Industry	Sept. 2012	P.3.1.7

3.3.3.2 E-Source

The Source e-News Update, distributed each Tuesday and Friday through email, is KCP&L's internal electronic newsletter. The publication's goal is to communicate pertinent information to all employees in a timely and effective manner. Community involvement, news from throughout the service territory, meetings, upcoming company initiatives, training and safety information are commonly included in the *e-News Update*. The SGDP was featured in E-Source on several occasions, as shown in Table 3-18.

Table 3-18: The E-Source Articles

Initiative	Date	Appendix
SmartGrid Comes to Leadership Link	Oct 08, 2010	P.3.2.1
SmartGrid Meter Rollout Has Begun	Oct 26, 2010	P.3.2.2
A Battery-Powered Substation?	May 15, 2012	P.3.2.3
KCP&L Opens Innovation Park to Promote SmartGrid	Oct 12, 2012	P.3.2.4
SmartGrid Demonstration is Wrapping Up	Nov 4, 2014	P.3.2.5

3.3.3.3 Employee Communications via TV Monitors, email, and Employee Meetings

The SGDP was featured in other employee communications on several occasions, as shown in Table 3-19.

Table 3-19: Other Employee SmartGrid Communications

Initiative	Outlet	Date	Appendix
KCP&L SmartGrid Demonstration Project	IT Briefing	Oct. 05, 2009	
KCP&L SmartGrid Demonstration Project - IT Priority Requirements	IT Briefing	Oct. 16,2009	
SmartGrid Important Announcement	Internal Email	Nov 24, 2009	P.3.3.1
KCP&L SmartGrid Briefing	T&D SRS Team	Jan. 06, 2010	
Customer Value Proposition	Presentation	July 28, 2010	
SmartGrid Support Team Training	Presentation	Sept 13, 2010	
SmartGrid Resident Employees' Lunch	1KC Place	Sept 14, 2010	
Afternoon of Sharing	1KC Auditorium	Sept 27, 2010	
SmartGrid Project Email to All Employees	Internal Email	Sept 07, 2010	P.3.3.2
KCP&L SmartGrid – Energy Solutions Meeting	Dept. Presentation	Nov. 02,2010	
SmartGrid Demonstration Project Update	Dept. Presentation	Multiple	
SmartGrid Demonstration Project 2010-2014	New Employee Orientation	Multiple	
SmartGrid Customer End Use – The future of Energy	Summer Intern Breakfast	June 16, 2014	

3.3.3.4 Leadership Link Videos

During 2009 and 2010 KCP&L management produced Leadership Link, a series of short informational videos, designed to educate employees on current company initiatives and emerging industry trends. The SGDP was featured in several Leadership Link videos', as shown in Table 3-20.

Table 3-20: Leadership Link Videos

Topic	Featured Management Team Member	Date
SmartGrid	Mike Deggendorf, Sr. VP Delivery	2009
Benefits of the SmartGrid Demonstration Project	Steve Gilkey, Sr. Dir., T & D Engr. & Planning	2010
Why the SmartGrid Project is in the Urban Core	Steve Gilkey, Sr. Dir., T & D Engr. & Planning	2010
SmartGrid Project Update	Steve Gilkey, Sr. Director, T & D Engineering	2010
Understanding SmartGrid	Bill Menge, Director SmartGrid	2010
Understanding SmartGrid (SmartEnd-Use)	Gail Allen, Sr. Mgr. Customer Solutions	2010
Understanding SmartGrid (Education & Outreach)	Paul Snider, Sr. Mgr. Government Affairs	2010
Understanding SmartGrid (SmartSub./Dist./Gen.)	Scott Grafelman, Mgr. Asset Mgmt. & Planning	2010
Understanding SmartGrid (SmartMeter)	Vicki Barszczak, Mgr. Mtr. Reading & Field Svc.	2010

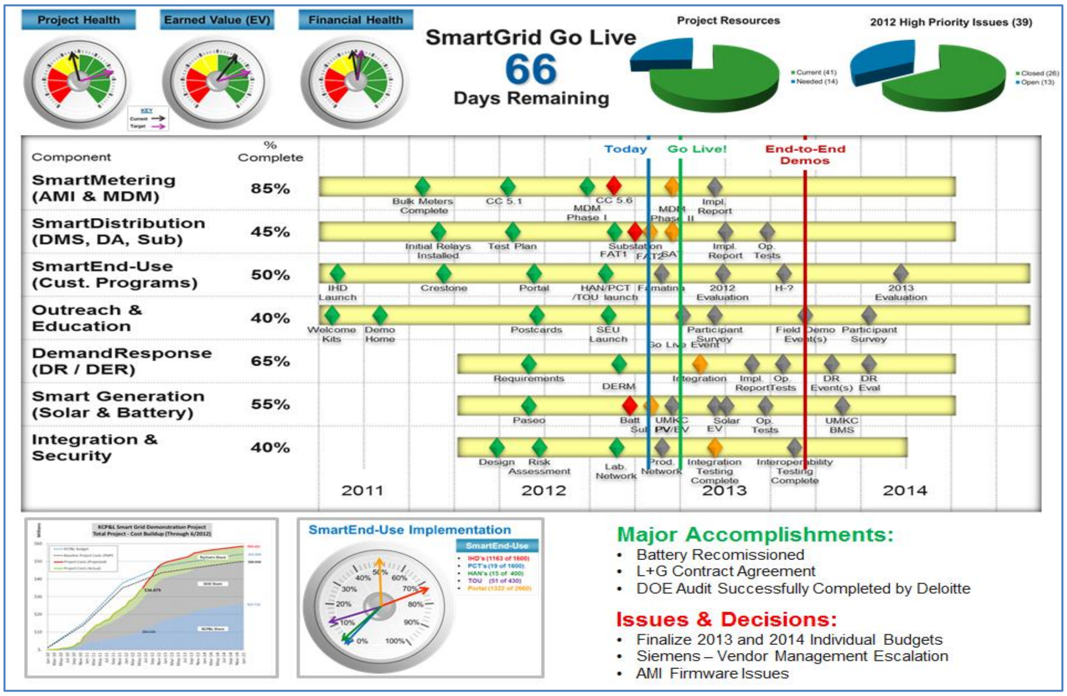
3.3.3.5 SmartGrid Snippets

During the summer of 2012, the SGDP team published a project-specific newsletter, SmartGrid Snippets, on a weekly basis. The SmartGrid Snippets communicated updates for each of the subprojects, as well as key milestones, resolved issues, and new issues for the overall project. Several samples of the SmartGrid Snippets are presented in Appendix P.3.4.

3.3.3.6 SmartGrid Project Sponsor Team Meetings

Regular SmartGrid Project Sponsor Team meetings were conducted as a component of the comprehensive Project Management Plan executed by the project PMO. The SmartGrid Project Sponsor Team is comprised of the Project Director and key KCP&L executives. The Project Director and PMO staff conduct the briefings that cover overall project progress; address key strategic, operational, and financial issues; provide strategic guidance; and address other issues escalated by the PMO. Figure 3-22 contains a sample Project Management Dashboard that was incorporated into each of the Sponsor Team briefings. These regular briefings help ensure that the KCP&L project sponsors are engaged and informed of project status on a continual basis.

Figure 3-22: Project Management Dashboard



3.3.3.7 Executive Management Briefings

In addition to the SmartGrid Project Sponsor Team meetings, the PMO had provided periodic SGDP updates and technology briefings to KCP&L Board of Directors and executive leadership teams. The following table provides a listing of these SGDP briefings and their respective audiences.

Table 3-21: Executive Management Briefings

Initiative	Outlet	Date
Senior Strategy Team Review	Project Presentation	Dec. 09,2009
Senior Strategy Team Update	Project Overview Presentation	April 27, 2010
Senior Strategy Team Update	Customer Value Proposition	July 28, 2010
Officers' Team Meeting	Project Overview Presentation	Aug. 23, 2010
Executive One-on-One Meetings	Project Update Presentation	Numerous
Vice President Staff Meetings	Project Overview Presentation	Numerous
Officers' Team Meeting	Project Update & TOU Rate Pilot	Oct. 25, 2011
Board of Directors Meeting	Project Update Presentation	May 01, 2012
Executive Technology Tour & Overview	Innovation Park Tour	Nov. 27, 2012
Smart Grid End-two-End Interoperability	Executive Sponsor Demonstration	Jan. 13, 2014

3.3.4 State Agencies, Legislators and Regulators

One of KCP&L's education and education objectives with the SGDP was to transfer its knowledge, experience, and learning to state agencies, legislators and regulators. Table 3-22 provides a listing of SGDP briefings made to and the leader of these respective audiences. The following subsections describe additional communication channels that were used to communicate project experiences and learning more broadly to the respective agency staff.

Table 3-22: State Agency, Legislator and Regulator Briefings

Topics	Group	Date
KCP&L SmartGrid Project Overview	KS House Energy & Utility Committee	Jan. 25, 2011
KCP&L Smart Grid Demonstration Project	Citizens Utility Ratepayer Board	April 13, 2011
SmartGrid Vision & Strategic Objectives SmartGrid Project Overview & Project Area Customer Engagement & Education Project Components & Timeline	MO Commissioners Agenda Session	Sept. 07, 2011
KCP&L Smart Grid Demonstration Project	MO Public Service Commission SmartGrid Workshop	Nov. 29, 2011
Project Status Update	Kansas Corporation Commission Open Meeting	Feb. 29, 2012
SmartGrid Vision & Strategic Objectives SmartGrid Project Overview & Project Area Project Components & Timeline	KS House Energy & Utility Committee	March 02, 2012
SmartGrid Project Overview SmartGrid Education & Outreach Project Accomplishments & Milestones	KS House Energy & Environment Committee	Feb. 07, 2013
Project Status Update	MO Public Service Commission Agenda Session	March 27, 2013

3.3.4.1 State Regulatory Commission Proceedings

KCP&L's retail operations are regulated by both the Missouri Public Service Commission (MPSC) and the Kansas Corporation Commission (KCC). As such, KCP&L participates in any formal proceedings initiated by or with either regulatory body. The future smart grid is being discussed in a variety of proceedings. KCP&L will continue to participate and provide appropriate input to all future proceedings regarding the smart grid. The following subsections summarize some Commission proceedings during the course of the project that have directly involved smart grid topics.

3.3.4.1.1 MPSC PURPA Considerations Required by EISA

On December 19, 2007, the Energy Independence and Security Act of 2007 (EISA) was signed into law, requiring state utility commissions to consider the standards set out in the EISA, including smart grid. On December 17, 2008 the MPSC established the workshops to do so. The docket opened for smart grid consideration was EW-2009-0292. Since establishment of this docket, KCP&L responded to requests for information and participated in a workshop on May 18, 2010 presenting information regarding its SGDP. KCP&L also participated in a second MPSC-sponsored workshop that included smart grid vendors on June 28 and June 29, 2010. KCP&L participated in additional MPSC sponsored workshops that culminated in revisions to the Integrated Resource Planning Rules and the creation of Renewable Energy Standard Rules and Missouri Energy Efficiency Investment Act Rules. On March 27, 2013, the MPSC closed the dockets related to consideration of the EISA Smart Grid standards.

3.3.4.1.2 KCC PURPA Considerations Required by EISA

On December 19, 2008, the KCC opened Docket No. 09-GIME-360-GIE for the purpose of investigating the standards as directed by EISA. KCP&L supplied comments regarding the standards on January 30, 2009. On September 18, 2009, KCP&L participated in the KCC Smart Grid roundtable. On December 14, 2009, the KCC closed this docket, electing not to adopt the EISA Smart Grid standards.

3.3.4.1.3 MPSC Integrated Resource Planning (IRP) Rulemaking

On May 15, 2009, the MPSC opened Docket No. EW-2009-0415 for the purpose of conducting workshops and providing a repository for work done in conjunction with rewriting the commission rules and procedures related to the IRP that each utility must conduct. Workshops were held and KCP&L participated in those workshops. On March 10, 2010, the MPSC opened a rulemaking case, EX-2010-0254 and subsequently published its IRP Proposed Amendment in the Missouri Register on December 1, 2010. Comments were to be provided to the MPSC and a Public Hearing was conducted January 6, 2011. On March 2, 2011, the MPSC adopted revisions it the Integrated Resource Planning Rules. The rule as proposed includes provisions requiring utilities to address “contemporary issues” and a requirement for “Analysis Required for Transmission and Distribution Network Investments to Incorporate Advanced Technologies”, which are intended to include analysis of smart grid technologies in future triennial integrated resource plans developed by all Missouri utilities.

In April 2012 KCP&L filed its first triennial IRP under these new rules. In this filing, KCP&L stated that “upon completion of the SmartGrid Demonstration Project KCP&L plans to use the findings of the project to develop a well-founded SmartGrid Vision, Architecture, and Road Map that will provide framework evaluating the feasibility of and guiding the implementation of advanced distribution grid technologies and become an integral component of future IRP filings”. The IRP process continues. Discussion will be updated in future releases of this report.

3.3.4.2 MO and KS SmartGrid Stakeholder Groups

Because several aspects of the SGDP require MPSC approvals, KCP&L initiated communication with various Missouri smart grid stakeholders to create an informal group. The purpose of this group is to inform relevant parties about the SGDP and to solicit input from them.

The members of the stakeholder group include representatives of the MPSC Staff, Office of Public Counsel, and Missouri Department of Natural Resources. On July 23, 2010, the initial meeting was held with the Missouri SmartGrid stakeholder group to introduce team members and give an overview of the SGDP. The following topics were discussed in the initial meeting:

- Smart Grid Vision and SGDP Overview
- SGDP Technology and Interoperability
- The Community and Our Customers
- The Customer Value Proposition
- SGDP Timelines
- How We Continue to Collaborate

On September 20, 2010, another meeting was held with the MO SmartGrid Stakeholder group to specifically discuss the KCP&L SGDP customer communication plan.

The idea of SmartGrid Stakeholder Group was so well received by the MO Stakeholders and since knowing that any future system-wide adoption of SmartGrid technologies may be reviewed by both the MO and KS commissions, KCP&L initiated a similar informal SmartGrid stakeholder group with the KCC staff and other KS stakeholder groups. Table 3-23 provides a listing of the periodic stakeholder meetings that occurred to discuss technology choices, evaluation plans, customer programs, customer service issues and status updates.

Table 3-23: Stakeholder Project Update Meetings

Topic	Group	Date
Initial SmartGrid Project Overview	MO Stakeholders	July 23,2010
Project Customer Communication Plan	MO Stakeholders	Sept. 20, 2010
SmartGrid Deployment Status RF Technical Overview & Selection Grid Systems & Technology Evaluation Strategy Smart End-Use Program Evaluation Strategy	MO Stakeholder	Feb 24, 2011
	KS Stakeholder	March 30,2011
Project Status Update Metrics & Benefits Plan Summary Customer Product Road Map	MO Stakeholder	June 27, 2011
	KS Stakeholder	July 15,2011
Distribution & Substation Project Component Overview	MO Stakeholders	Aug. 26, 2011
	KS Stakeholders	Aug. 26, 2011
Project Status Update Customer Engagement & Education TOU Rate Design Solar Updates	MO Stakeholder	Oct. 21, 2011
	KS Stakeholder	Nov. 04, 2011
Project Status Update	MO Stakeholder	Jan. 30, 2012
Project Status Update Solar & EV Charging Selection TOU & Grid Battery Update	MO Stakeholder	April 30, 2012
	KS Stakeholder	May 15, 2012
Project Status Update SmartGrid Architecture Overview SmartGrid Integration Road Map	MO Stakeholder	July 26, 2012
	KS Stakeholder	Aug. 09, 2012
Project Status Update SmartGrid Innovation Park & Ribbon Cutting	MO Stakeholder	Nov. 02,2012
	KS Stakeholder	Nov. 09, 2012
Project Status Update Interoperability Testing Overview Product Enrollment and TOU Stats DOE Financial Audit Results	MO Stakeholder	April 16, 2013
	KS Stakeholder	April 19, 2013
Project Status Update Integration & Interoperability Testing Update SmartGrid Customer Products Grid Connected Battery	MO Stakeholder	July 26, 2013
	KS Stakeholder	Aug. 19, 2013
Project Status Update Integration & Interoperability Testing Update Operational Test Plan Solar and EVSE Completion Status	MO Stakeholder	March 19, 2014
Project Status Update Customer End-Use Update Summer 2014 Demand Response Plan	MO Stakeholder	May 12, 2014
	KS Stakeholder	June 20, 2014
Project Status Update Project Close-out Communications Decommissioning Plans Remaining DOE Reporting	MO Stakeholder	Nov. 21, 2014

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3.3.4.3 MO and KS Commission Staff

The MPSC and KCC each received separate DOE funding to support additional smart grid staff and staff education. In addition to the more organized interactions with the commission described in the previous section, KCP&L invited both Missouri and Kansas smart grid staff to participate in several SGDP design and knowledge transfer workshops and meetings. In addition to the regular SmartGrid Stakeholder meetings the MPSC and KCC staffs participated in the following project opportunities.

- KCP&L hosted a “Day of Sharing” on January 28, 2010 with the Green Impact Zone, which both the MPSC and KCC smart grid staff attended. They learned about the challenges and opportunities specific to the Green Impact Zone.
- On February 10 and 11, 2010, KCP&L hosted a smart grid technical conference with project vendor partners. Both the MPSC and KCC staffs were represented and were able to ask questions and broaden their understanding of the interdependencies the project vendors were working through.
- On May 10, 2010, Steve Gilkey, KCP&L, Sr. Director T&D Engineering presented an overview of the SGDP at a MO PSC hosted SmartGrid workshop. The workshop was attended by Commissioners and Commission staff.
- In October 2010, EPRI conducted a series of smart grid use case workshops with KCP&L subject matter experts. The Commission smart grid staff was represented at several of the sessions and was able to ask questions and broaden their understanding of the use case process and how it would be used to document the project interoperability requirements.

3.3.5 Electric Utilities and Smart Grid Industry

Another of KCP&L’s education and education responsibilities with the SGDP was to transfer its project knowledge, experience, and learning to other utilities and the smart grid industry as a whole. The following sections describe some to the communications channels that were used to meet this requirement.

3.3.5.1 EPRI’s Smart Grid Demonstration Program Participation

As a member of EPRI’s five-year Smart Grid Demonstration Program, KCP&L’s technology transfer activities were coordinated through EPRI’s formalized Smart Grid Demonstration Program. Specifically, EPRI coordinated the sharing of field results, lessons learned, architectural challenges, issues impacting standards, key technology gaps and useful tools to help interoperability of smart grid technologies and systems related to the program. In addition, detailed KCP&L SGDP information was communicated via EPRI’s Smart Grid resource center (www.smartgrid.epri.com) and additional technology transfer activities including workshops, webcasts and periodic publications. The workshops included presentations on status of field demonstrations, lessons learned to date, architectural challenges, issues impacting standards and common interest areas to explore. Technical summaries in the form of presentations and white papers/articles were prepared for public dissemination. These publications included a synthesis of contributions to standards bodies and common messages to deliver to industry and public entities such as state and federal agencies.

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Table 3-24: Project Related EPRI Publications

Title	Audience	EPRI Product ID	Date
EPRI Smart Grid Overview	Public	Flyer	Sept. 2008
Smart Grid Advisory Update Newsletter	Advisors	Newsletter	March 2009
Smart Grid Advisory Update Newsletter	Advisors	Newsletter	April 2009
Smart Grid Advisory Update Newsletter	Advisors	Newsletter	June 2009
EPRI SmartGrid Demonstration Project Update	Advisors	Presentation	June 23, 2009
Smart Grid Advisory Update Newsletter	Advisors	Newsletter	Aug. 2009
EPRI Smart Grid Demonstration Overview	Public	1020225	Sept. 22, 2009
Smart Grid Advisory Update Newsletter	Advisors	Newsletter	Oct. 2009
EPRI SmartGrid Demonstration Project Update	Advisors	Presentation	Oct. 12, 2009
Smart Grid Advisory Update Newsletter	Advisors	Newsletter	Jan. 2010
Smart Grid Advisory Update Newsletter	Advisors	Newsletter	March, 2010
EPRI Smart Grid Demonstration Overview	Advisors	Presentation	March 3, 2010
EPRI SmartGrid Demonstration Update	Advisors	Presentation	March 4, 2010
KCP&L Architecture Operational Functions	Advisors	Presentation	March 4, 2010
KCP&L Smart Grid Host Site Project Description	Members	1020892	April 01, 2010
Smart Grid Advisory Update Newsletter	Advisors	Newsletter	May 2010
SmartGrid Demonstration Project Update	Advisors	Presentation	June 10, 2010
Smart Grid Advisory Update Newsletter	Advisors	Newsletter	Aug. 2010
KCP&L Smart Grid Demonstration Overview	Public	1021418	Aug. 06, 2010
Smart Grid Demonstration Two-Year Update	Public	1021497	Aug. 20, 2010
Smart Grid Advisory Update Newsletter	Advisors	Newsletter	Nov., 2010
Smart Grid Advisory Update Newsletter	Advisors	Newsletter	Feb., 2011
Smart Grid Advisory Update Newsletter	Advisors	Newsletter	March, 2011
Smart Grid Advisory Update Newsletter	Advisors	Newsletter	May, 2011
Smart Grid Demonstration Three-Year Update	Public	1023411	July 21, 2011
Smart Grid Advisory Update Newsletter	Advisors	Newsletter	Aug., 2011
KCP&L/EPRI SmartGrid Demonstration Video	Public	http://www.youtube.com/watch?v=kXc6c_I1wOU&list=UUctcciH1NrAGpwMnKwvnLgQ&index=18&feature=plpp_video	Oct. 19, 2011
Smart Grid Advisory Update Newsletter	Advisors	Newsletter	Nov., 2011
KCP&L Smart Grid Host Site 2011 Progress Report	Members		
Smart Grid Advisory Update Newsletter	Advisors	Newsletter	Feb., 2012
Smart Grid Advisory Update Newsletter	Advisors	Newsletter	April, 2012
Smart Grid Advisory Update Newsletter	Advisors	Newsletter	May, 2012
Smart Grid Demonstration Four-Year Update	Public	1025781	July 26, 2012
Smart Grid Advisory Update Newsletter	Advisors	Newsletter	Aug., 2012
Case Study on Customer Acceptance and Technology Adoption: Kansas City Power & Light	Members	1026444	Oct. 31,2012
Smart Grid Advisory Update Newsletter	Advisors	Newsletter	Jan., 2013
KCP&L SmartGrid Demonstration Deep Dive	Advisors	Webcast	Feb. 21, 2013
Smart Grid Advisory Update Newsletter	Advisors	Newsletter	March, 2013
KCP&L Smart Grid Host Site 2012 Progress Report	Members	1025759	April 29, 2013
Smart Grid Advisory Update Newsletter	Advisors	Newsletter	May/June 2013
Smart Grid Demonstration Five-Year Update	Public	3002000778	Aug. 10, 2013
Smart Grid Advisory Update Newsletter	Advisors	Newsletter	Sept/Oct 2013
Smart Grid Advisory Update Newsletter	Advisors	Newsletter	Nov/Dec 2013
Smart Grid Advisory Update Newsletter	Advisors	Newsletter	Feb/Mar 2014
Smart Grid Advisory Update Newsletter	Advisors	Newsletter	June/July 2014
Smart Grid Advisory Update Newsletter	Advisors	Newsletter	Sept. 2014
Smart Grid Advisory Update Newsletter	Advisors	Newsletter	Oct. 2014
EPRI Smart Grid Demonstration Initiative Final Update	Public	3002004652	Oct. 22, 2014
Smart Grid Advisory Update Newsletter	Advisors	Newsletter	Dec. 2014

3.3.5.2 Technical Project Website

KCP&L created an industry focused SGDP website as an extension of its customer focused website, www.kcplsmartgrid.com/industry-resources . This website was created in collaboration with the project partners, and allowed agencies, legislators, regulators, other utilities and the smart grid industry as a whole to remain abreast of the SGDP.

Figure 3-23: *www.kcplsmartgrid.com/*industry-resources Page Screenshot

3.3.5.3 Industry Publications

One of the most effective ways to transfer knowledge to a diverse audience is through industry publications. The publications, listed below, were prepared for public dissemination throughout the life of the SGDP, and they included a combination of contributions to standards bodies and industry publications.

Table 3-25: Industry Publications

Material	Title	Publication	Date	Appendix
Article	The Greening of Kansas City	EnergyBiz	Sept/Oct 2009	P.5.1.1
Article	State Limelight – Missouri's smart grid progress	IntelligentUtility	Sept/Oct 2009	P.5.1.2
Press Release	KCP&L to Receive Stimulus Grant for KC SmartGrid Demonstration	Multiple	Nov. 24, 2009	P.5.1.3
Press Release	KCP&L Selects Siemens for SmartGrid Demonstration Project	Multiple	Nov. 24, 2009	P.5.1.4
Press Release	KCP&L Selects Intergraph Smart Grid Technology	Multiple	Dec. 01, 2009	P.5.1.5
Press Release	Landis+Gyr Supports SmartGrid Demonstration Project at KCP&L	Multiple	Sept. 09, 2010	P.5.1.6
Article	Project Living Proof	Greenability Magazine	Sept/Oct 2010	P.5.1.7
Press Release	Tendril Selected for KCP&L SmartGrid Demonstration Project	Multiple (energy central)	Oct. 15, 2010	P.5.1.8
Press Release	KCP&L Launches Smart Grid Project	Multiple	Nov. 10, 2010	P.5.1.9
Press Release	OATI is Selected for the KCP&L SmartGrid Demonstration Project	Multiple	Jan. 01, 2011	P.5.1.10
Press Release	KCP&L has selected Siemens to implement Smart Grid technology	Multiple	Feb. 02, 2011	P.5.1.11
Article	Customer engagement highlighted in Kansas City	EnergyBiz Insight	April 06,2011	P.5.1.12
Press Release	KCP&L Completes Smart Meter Installation	Multiple	April 29, 2011	P.5.1.13
Press Release	KCP&L using Siemens, eMeter for smart Grid initiatives	Multiple	May, 23, 2011	P.5.1.15
Press Release	L+G Helps KCP&L Reach Important Milestone in SmartGrid Project	Multiple	May 10, 2011	P.5.1.15
Article	Smart grid as economic development?	IntelligentUtility	May/June 2011	P.5.1.16
Article	In the Heart of America: Smart Grid Demonstration – Kansas City's SmartGrid Takes Shape	Burns & McDonnell Benchmark	June 01, 2011	P.5.1.17
Press Release	Tendril Announces Shipments of Energize Consumer Engagement Technology	Multiple	July 13, 2011	P.5.1.18
Press Release	KCP&L Announces Solar Project in Green Impact Zone	Multiple	Oct. 28, 2011	P.5.1.19
Article	Community Engagement	T&D World	Nov. 01, 2011	P.5.1.20
Press Release	OpenADR Alliance Demonstrates Interoperability with new OpenADR 2.0 Smart Grid Standard	Multiple	Nov. 09, 2011	P.5.1.21
Press Release	KCP&L Begins EV Charging Pilot Program Using Coulomb Technologies ChargePoint Network	Multiple	Nov. 14, 2011	P.5.1.22
Article	Wired for Success	T & D World	April, 2012	P.5.1.23
Article	KCP&L shares smart grid lessons learned	FierceSmartGrid	April 25, 2012	P.5.1.24
Article	How KCP&L uses behavioral science (and a web portal) to improve consumer engagement	SmartGrid News	May 24, 2012	P.5.1.25
Article	Leveraging Behavioral Science for Persistent Customer Engagement Webinars #1-4	Smart Grid News	June 11, 2012	P.5.1.26
Article	Urban revitalization and grid modernization?	EnergyBiz Insights	June 12, 2012	P.5.1.27
Article	Drilling Deep for greater achievements	IntelligentUtility	July/Aug 2012	P.5.1.28
Press Release	ABB (Tropos) to supply broadband wireless network to KCP&L	Multiple	Aug. 29, 2012	P.5.1.29
Press Release	KCP&L Officially Opens Innovation Park	Multiple	Oct. 12, 2012	P.5.1.30

Material	Title	Publication	Date	Appendix
Press Release	KCP&L Pilots New Energy Storage System	Multiple	Oct. 16, 2012	P.5.1.31
Press Release	OATI and KCP&L Announce Completion of Acceptance Testing on Smart Grid Solution	Multiple	Dec. 04, 2012	P.5.1.32
Article	DistribuTECH 2013: Comprehensive smart grid pilot being developed by KCP&L with support from DOE	Between the Poles	Feb. 06, 2013	P.5.1.33
Article	Demonstrating a Battery's Benefits	Burns & McDonnell Benchmark	Q2 2013	P.5.1.34
Article	A New Breed of Distribution Substation	PowerGrid International	Jan. 2014	P.5.1.35
Technical Paper	Model-Based, Substation-Centric Distribution Automation	CIGRE Session 2014	Aug. 24-29, 2014	P.5.1.36

3.3.5.4 Industry Conferences

In addition to published documents, KCP&L sought to transfer knowledge and experience to industry groups through presentations at industry conferences. The presentations listed in the following table included content on project status, challenges faced, specific technical topics, interoperability issues or lessons learned.

Table 3-26: Industry Conference Presentations

Topics	Group	Date
KCP&L SmartGrid Overview	Mid-American Regulatory Conference	June 8, 2010
KCP&L SmartGrid Pilot and Energy Optimizer Program	Kansas Energy Conference 2010	Oct. 12, 2010
Business Transformations & The Smart Grid	GridWeek 2010	Oct. 18-21, 2010
Developing a SmartSubstation Architecture for the SmartGrid	GridWeek 2010	Oct. 18-21, 2010
Journey to Quality Through Automation Evolution	Galvin Electricity Initiative Conference	Dec. 2010
KCP&L SmartGrid	A&WMA-Midwest Section Annual Environmental Conference	Jan. 19, 2011
KCP&L SmartSubstation Demo - A Partnership with Siemens	DistribuTECH 2011	Feb. 2, 2011
From the Meter to the Customer – KCP&L's SmartGrid Project Focuses On More Than The Technology	2011 Customer Service Conference & Exposition	April 4, 2011
KCP&L Smart Grid Demonstration Project	Distribution Automation 2011 Conference	April 28, 2011
Kansas City Power & Light's End-to-End SmartGrid Demonstration	2011 Landis+Gyr Exchange User Conference	May 5, 2011
Kansas City Power & Light's End-to-End SmartGrid Demonstration	Honeywell User Group Conference	June 5, 2011
State of Deployment – Consumer Behavior	GridWeek 2011	Sept. 13, 2011
KCP&L Developing a Smart Grid – Systems Integration	GridWeek 2011	Sept. 14, 2011
KCP&L SmartGrid - Experience Beyond Technology	Chartwell EMACS Conference	Oct. 27, 2011
SmartGrid Demo and Home Area Networks	T&D World/CIGRE Game Changers Conference	Nov. 16, 2011
Layered Distribution Automation and KCP&L's SmartGrid Demo Project	Electric Light & Power Executive Conference	Jan. 22, 2012
KCP&L Smart Grid Demonstration Project	DistribuTECH 2012	Jan. 24, 2012
Creating Meaningful Consumer Engagement	2012 Smart Grid RoadShow	April 17, 2012
KCP&L SmartGrid Update	2012 Landis+Gyr Exchange User Conference	April 25, 2012
KCP&L Smart Grid Demonstration Project	2012 Sustainable Housing Conference	Sept. 20, 2012
KCP&L Smart Grid Demonstration Project	2012 Kansas Energy Conference	Sept. 26, 2012
Customer Engagement Through Social Media	GridWeek 2012	Oct. 4, 2012
The Future of Energy and Creating a Sustainable Community	Sustainability Forum	Oct. 10, 2012
KCP&L Smart Grid Demonstration Project	OATI User Group Conference	Oct. 17, 2012
KCP&L Smart Grid Demonstration Project	Midwest Energy Policy Conference	Oct. 25, 2012
KCP&L Smart Grid Demonstration Project	CIGRE Grid of the Future Symposium	Oct. 29, 2012

Topics	Group	Date
Deploying a Distribution Management System in a Pilot Project	Minnesota Power Systems Conference	Nov. 7, 2012
Demonstrating and Uncovering the Benefits of a State-of-the-art Next Generation Smart Distribution System	DistribuTECH 2013	Jan. 29, 2013
Pushing the Envelope on Substation Automation: KCP&L's End-to-End Smart Substation and Smart Distribution Initiatives	DistribuTECH 2013	Jan. 29, 2013
KCP&L's End-to-end Smart Grid Demonstration Pushes the DR Event Messaging Standards Envelope	DistribuTECH 2013	Jan. 30, 2013
Innovative Methods and Solutions Drive KCP&L's End-to-end Smart Grid Program	DistribuTECH 2013	Jan. 30, 2013
KCP&L Advanced Distribution Automation to Deliver Electricity More Reliably and Efficiently	DistribuTECH 2013	Jan. 30, 2013
Lessons from the Field: Consumer Engagement is a Journey, Not A Destination	DistribuTECH 2013	Jan. 30, 2013
Success Stories in Integrating New Customer-facing Technologies	DistribuTECH 2013	Jan. 30, 2013
Priming the Pump: What's Working and Delivering Value from the Recovery Act - PANEL	DistribuTECH 2013	Jan. 30, 2013
Greening the Grid with Smart Generation: Small-scale Renewable Integration and Sustainability Initiatives at KCP&L	DistribuTECH 2013	Jan. 31, 2013
KCP&L Green Impact Zone SmartGrid Demonstration Project	IEEE-PES ISGT Conference	Feb. 25, 2013
The Power of Web Portals	2013 CS Week	May 2, 2013
Advancements in Distribution Automation to Deliver Electricity More Reliably and Efficiently: A Kansas City Power & Light Case Study	UTC Telecom 2013	May 15, 2013
Integration of Variable Generation Resources - A Distribution Grid Perspective	OATI User Group Conference	Oct. 8, 2013
KCP&L Green Impact Zone SmartGrid Demonstration Project		
How Customer Engagement is Transforming Utility Operations	DistribuTECH 2014	Jan. 28, 2014
Pushing the Envelope on Substation Automation: Part2 - KCP&L's End-to-end Smart Substation and Smart Distribution Initiatives	DistribuTECH 2014	Jan. 28, 2014
Energy Storage: Technologies, Operations and Value Propositions	DistribuTECH 2014	Jan. 29, 2014
Integration of Smart Substations in Advance DMS: A Case for Integrated Self-healing Applications	DistribuTECH 2014	Jan. 30, 2014
Advanced Metering Insights: KCP&L's Evolution to AMI/MDM-based Smart Metering	DistribuTECH 2014	Jan. 30, 2014
Emerging Variable Generation Operational Impacts and Mitigation Measures Panel	IEEE-PES ISGT Conference	Feb. 19, 2014
Enabling SmartGrid Functions through End-to-End Systems Interoperability	IEEE-PES ISGT Conference	Feb. 19, 2014
Application of IEC61970 and IEC61968 at KCP&L Smart Grid Demonstration Project	IEEE-PES ISGT Conference	Feb. 20, 2014
Lessons Learned When Selecting Customers for a Smart Grid Pilot	2014 CS Week	May 08, 2014
Model-Based, Substation-Centric Distribution Automation	CiGRE Session 2014 - Paris	Aug. 24-29, 2014
KCP&L's DERM Implementation in a SmartGrid Demonstration Project	OATI User Group Conference	Oct. 15, 2014
KCP&L's Experiences with IEC 61850 GOOSE Messaging in a SmartDistribution Substation Implementation	DistribuTECH 2015	Feb. 05, 2015
KCP&L's Smart Grid Demonstration Project: Gaps Identified in Current SmartDistribution Technologies Requiring Evolution to Support Emerging Functionality	DistribuTECH 2015	Feb. 03, 2015
KCP&L's SmartGrid Demonstration Project's Hierarchical Demand Response Management Implementation Leveraging Multiple DR Messaging Standards	DistribuTECH 2015	Feb. 03, 2015
Beyond KCP&L's DOE SmartGrid Demonstration Project: Technological Assessment Results of Project Component Readiness for Enterprise Deployment	DistribuTECH 2015	Feb. 04, 2015
KCP&L's 1MWh Battery Energy Storage System (BESS): An Overview of Operational Functions and Benefits	DistribuTECH 2015	Reserve
Model Based-Substation Centric Distribution Automation	DistribuTECH 2015	Reserve

Industry conference participation continues.

3.3.5.5 Technical Education

In addition, KCP&L sought to transfer knowledge and experience through technical training sessions, such as workshops and webinars. These sessions included content on project status, challenges faced, specific technical topics, interoperability issues or lessons learned.

Table 3-27: Industry Workshops and Webinars

Topics	Group	Date
KCP&L Smart Grid Demonstration Project	EPRI Peer Review Webcast	Feb. 3, 2010
Smart Grid Demonstration Project	EPRI Advisory Meeting	Sept. 13, 2010
Changing Customer Behavior to Utilize Energy Intelligently and Efficiently	Marcus Evans Conference	Sept. 30, 2010
KCP&L Smart Grid Demonstration Project	EPRI Project Update	Oct. 25, 2010
DOE Project Kick-Off Meeting	DOE Meeting	Jan 6, 2011
From the Meter to the Customer – KCP&L's SmartGrid Project Focuses On More Than The Technology	Edison Electric Institute	March 21, 2011
KCP&L Smart Grid Demonstration Project	National League of Cities	June 3, 2011
KCP&L Smart Grid Demonstration Project	Oklahoma Gas & Electric SmartGrid Team	July 12, 2011
KCP&L Smart Grid Demonstration Project	Partnership for Emergency Planning	July 21, 2011
From the Meter to the Customer – KCP&L's SmartGrid Project Focuses On More Than The Technology	Chartwell EMACS 2012	July. 30, 2012
KCP&L Smart Grid Demonstration Project	Siemens Energy Policy Panel	Sept. 13, 2011
Software Giants and the Home Area Network	Game Changers	Sept. 21, 2011
KCP&L Smart Grid Demonstration Project	EPRI Smart Grid Demonstration and Public Action Group Meetings	Oct. 18, 2011
KCP&L Smart Grid Demonstration Project	2011 APPA Facilities Drive-In Workshop	Nov. 16, 2011
KCP&L Smart Grid Demonstration Project	EPRI Deep-Dive Webcast	Nov. 17, 2011
From Enrollment to Engagement: A Roadmap to Reaching Your Customers	Chartwell Smart Grid Customer Interaction Summit	April 19, 2012
Leveraging Behavioral Science for Persistent Customer Engagement	Smart Grid Newsletter Webinar	June 07, 2012
KCP&L Green Impact Zone SmartGrid Demonstration Project	DOE Peer-to-Peer Meetings	June 08, 2012
SmartGrid Demonstration Project-Engaging the Customer	EPRI SmartGrid and Public Advisory Groups	June 21, 2012
KCP&L Smart Grid Demonstration Project – Case Study Brief	EPRI Four-Year Update	July 23, 2012
2012 DOE Project Review	DOE Visit	Aug. 20, 2012
KCP&L Smart Grid Demonstration Project	SGCC Peer Connect	Sept. 25, 2012
From Enrollment to Engagement: A Roadmap to Reaching Your Customers	Chartwell EMACS 2012	Oct. 11, 2012
KCP&L SmartGrid Demonstration Project	DOE/NRECA Midwest Peer-to-Peer	Dec. 12, 2012
Incentivizing Off Peak Programs	Chartwell Webinar	Dec. 13, 2012
KCP&L SmartGrid Demonstration Project Deep-Dive Webcast	EPRI Deep Dive	Feb. 21, 2013
SmartGrid Demo Project with Focus on Communications	Mid Central UTC Annual Meeting	March 26, 2013
SmartGrid Network Design and Implementation: A KCP&L Case Study	SmartGrid Observer – SmartGrid Virtual Summit	Oct. 03, 2013
Pricing/Rates: Customer Communications	Chartwell EMACS 2013	Oct. 10, 2013
KCP&L SmartGrid Demonstration Project Update	DOE Smart Grid Demo Projected Mtg.	Jan. 22, 2014
Smart Grid Contributions to Advancing Renewables	Advancing Renewables in the Midwest	April 08, 2014
Advanced Distribution Management Systems Workshop	DOE ADMS Working Group	May 01, 2014
SmartGrid R&D Peer Review	DOE	June 11-12, 2014
A Smarter Grid – It's All About the Consumer Panel	NEUAC Low Income Conference	June 19, 2014
DERM Panel	GTM Grid Edge Live	June 24-25, 2014
Advanced Distribution Management Systems Workshop	DOE ADMS Working Group	Oct. 15-16, 2014
A Distributed Resource Management Systems Architecture for Supporting Grid Operations	DOE/EPRI Conference - The Smart Grid Experience	Oct. 27, 2014
Customer Enrollment does not always mean customer engagement		Oct. 29, 2014

3.3.5.6 Local Business and Industry Association Presentations

In addition, KCP&L sought to inform and educate local business and industry organizations on smart grid concepts in general and provide an overview of the KCP&L SGDP and how they, our customers, will benefit from the knowledge and experience KCP&L has gained from the project.

Table 3-28: Local Business and Industry Association Presentations

Topics	Group	Date
Introduction to KCP&L's Smart Grid Demonstration Project for the Green Impact Zone	Mid America Regional Council	Aug. 17, 2009
Energy Efficiency and the SmartGrid	Green Impact Zone Ombudsmen	Aug. 27,2010
KCP&L Smart Grid Demonstration Project	Green Impact Zone Key Leaders	Sept. 14, 2010
KCP&L Smart Grid Demonstration Project	Rotary Australian Exchange	April 21, 2011
KCP&L Smart Grid Demonstration Project	Northeast Johnson County Chamber of Commerce	April 21, 2011
KCP&L Smart Grid Demonstration Project	Kansas City Area Development Council – Education Alliance	April 29, 2011
KCP&L SmartGrid Customer Education	Paseo High School	Feb. 17, 2012
KCP&L Smart Grid Demonstration Project	Kansas State University Advisory Board	March 28, 2012
SmartGrid Demo Project and Demo House Tour	Kansas State University – Electrical Engineering Grad Students	April 27, 2012
Meet Me At The Bridge - Smart Grid Benefits	City of KCMO	May 05, 2012
KCP&L Smart Grid Demonstration Project	Midwest Society of Professional Engineers	May 24, 2012
KCP&L Smart Grid Demonstration Project	IEEE Gold Affinity Group	June 14, 2012
KCP&L Smart Grid Demonstration Project	Sierra Club Meeting (at Anita Gorman Discover Center)	Aug. 7, 2012
KCP&L Smart Grid Demonstration Project	Going Live Celebration	Oct. 12, 2012
SmartGrid - An Overview of KCP&L Project	Johnson County Licensing Programs	Oct. 12, 2012
KCP&L Smart Grid Demonstration Project	Paseo High School	Nov. 19, 2012
KCP&L Smart Grid Demonstration Project	UMKC	April 13, 2013
KCP&L Smart Grid Demonstration Project	Brush Creek Corridor Planning and Development Forum	May 21, 2013
KCP&L Smart Grid Demonstration Project	PMI - Kansas City Chapter – PDD Conference	Sept. 30, 2013
KCP&L Smart Grid Demonstration Project	Union Station - Saturday Science Seminar	Oct. 12, 2013
KCP&L Smart Grid Demonstration Project	South Kansas City Chamber of Commerce Leadership	June 04, 2014

3.3.6 Targeted Education & Outreach Initiatives

In addition to the SGDP education and outreach initiatives described in the previous sections, the KCP&L teams from Public Affairs and Corporate Communications implemented special targeted initiatives for:

- AMI Deployment
- SmartEnd-Use Products
- SmartGrid Demonstration House
- SmartGrid Innovation Park

These targeted education and outreach initiatives are described in the following sections.

3.3.6.1 AMI Deployment

KCP&L teams from Public Affairs and Corporate Communications developed multiple channels to communicate with customers during the entire AMI implementation process. Information was mailed to the customers approximately 60 days prior to the first meter install explaining the project and letting them know what to expect. One month prior to scheduled meter change out the customer received a post card reminding them about the coming change. Another card with additional metering information was mailed one week prior to installation. Lastly, individuals and businesses received a phone call two days prior to installation.

- Smart Grid Residential Customer Letter Final – August 31, 2010. Mailed to all customers (residential and commercial) in early September 2010. The SmartGrid Fact Sheet was included. See Appendix P.2.1.2.
- KCP&L Smart Grid Mailer Postcard (residential and commercial). Mailed to customers approximately four weeks prior to smart meter installation. See Appendix P.2.1.3.
- Smart Grid Meter Installation Postcard. Mailed to customers approximately one week prior to smart meter installation. See Appendix P.2.1.4.
- Smart Grid Welcome Kit letter, Fact Sheet, Sorry We Missed You panel (if applicable), and Welcome Kit Booklet. Distributed to customer in person on day of meter exchange.
- KCP&L Smart Grid Demonstration House fact sheet. Copies available to visitors at the Demonstration House. See Appendix P.6.2.1.
- FAQ. Available on the web and distributed at events, along with the fact sheet.

All communication directed customers to a project specific web site, email address, and phone number to contact in the event they had questions or needed more information.

KCP&L created a dedicated Smart Grid Support Team to inform customers of the process and answer questions specific to the project. These employees were able to set appointments for installation and give customers timely answers to technology and implementation questions.

For a portion of the project area, on the day a customer’s meter was changed, Ambassadors went door to door offering residents an informational Welcome kit and addressed customer concerns face-to-face. Meter installers also made contact with residents immediately prior to exchange.

3.3.6.2 SmartEnd-Use Products

From a customer perspective, KCP&L’s SGDP includes a full suite of tools and products designed to help them manage energy usage and, as a result, potentially save money on their monthly bills. In the fall of 2010, KCP&L’s SmartGrid team branded these customer-facing tools as the “MySmart” suite of products.

- MySmart Portal: A personalized website that helps customers understand how they use electricity and enables them to make decisions that conserve energy, help the environment and save money.

- MySmart Display: A hand-held, in-home electronic device that takes information directly from the customer's meter and presents it in easy-to-understand screens that increase customers' awareness of their electricity use to help identify opportunities to reduce consumption and save money. The display does not require an Internet connection.
- MySmart Thermostat: For homes with central air conditioning, this thermostat can be programmed to automatically set temperatures based on the season, time of day and customers' schedules, helping them save money on heating and cooling bills.
- MySmart Network: A home area network that allows appliances, a thermostat and other end-use electrical devices to communicate with one another in the home. MySmart Network gives customers even greater insight into how they are using electricity along with the ability to set targets for monthly usage.
- MySmart (Time-of-Use) Rate: The option to switch to rates that are based on the time of day that electricity is used and the cost of supplying electricity at that time. Time-of-use rates encourage customers to save money by shifting consumption to Off-Peak periods.

To recruit participants to these demonstration programs, The KCP&L teams from Public Affairs and Corporate Communications developed a marketing approach and customer engagement strategy for each of the MySmart products. The MySmart product literature listed in Table 3-29 was developed to support the role out of the MySmart products.

Table 3-29: SmartEnd-Use Product Literature

Title	Product	Appendix
MySmart Products Flyer – Version 1	Multiple	P.6.1.1
MySmart Product Interest Form – Version 1	Multiple	P.6.1.2
MySmart Products Door Hanger	Multiple	P.6.1.3
MySmart Products Now What? Postcard	Multiple	P.6.1.4
MySmart Products Flyer – Version 2	Multiple	P.6.1.5
MySmart Product Interest Form – Version 2	Multiple	P.6.1.6
MySmart Products Interloop Mailer	Multiple	P.6.1.7
MySmart Portal Flyer	MySmart Portal	P.6.1.8
MySmart Portal Postcard	MySmart Portal	P.6.1.9
MySmart Display Flyer	MySmart Display	P.6.1.10
MySmart Display Letter (Blue Zone Letter)	MySmart Display	P.6.1.11
MySmart Display Postcard	MySmart Display	P.6.1.12
MySmart Display Gift Card Offer Postcard	MySmart Display	P.6.1.13
MySmart Display Drop Off Postcard	MySmart Display	P.6.1.14
MySmart Display Quick Start Guide	MySmart Display	P.6.1.15
MySmart Display User's Guide	MySmart Display	P.6.1.16
MySmart Thermostat Flyer	MySmart Thermostat	P.6.1.17
MySmart Thermostat FAQs	MySmart Thermostat	P.6.1.18
MySmart Thermostat Quick Start Guide	MySmart Thermostat	P.6.1.19
MySmart Thermostat User's Guide	MySmart Thermostat	P.6.1.20
MySmart Home Flyer	MySmart Home	P.6.1.21
MySmart Home FAQs	MySmart Home	P.6.1.22
MySmart Home Quick Start Guide	MySmart Home	P.6.1.23
MySmart TOU Rate FAQs	MySmart TOU Rate	P.6.1.24
MySmart TOU Rate Details	MySmart TOU Rate	P.6.1.25

3.3.6.3 SmartGrid Demonstration House

In 2006, the Metropolitan Energy Center (MEC) (www.kcenergy.org), with assistance from KCP&L, advanced the idea for Project Living Proof (PLP), a demonstration house, located at 917 Emanuel Cleaver II Blvd., to promote the development of sustainable communities by showcasing weatherization, landscaping, efficient appliances and other energy-efficient features.

KCP&L again invested in this project and the demonstration house by deploying existing and emerging renewable energy and energy management technologies. The demonstration house allowed KCP&L customers to experience the future of the energy and see first-hand the new MySmart tools and products available to customers in the SGDP area.

- Smart Meter. The smart meter unlocked the benefits of the SmartGrid by enabling two-way communication between the utility and the customer. This provided real-time energy usage information for consumer products such as the MySmart Portal, MySmart Display and MySmart Network. It also allowed customers to receive price signals and participate in "time of use" and other rate plans options.
- MySmart Portal. Each customer with a smart meter had access to a customized website to view usage information and receive additional updates on energy saving options.
- MySmart Display. This portable energy management tool provided consumers with access to current electricity usage and bill information.
- MySmart Thermostat The programmable thermostat helped customers save energy and helped KCP&L control peak demands.
- Rooftop Solar. The Solar Photovoltaic (PV) system was able to produce 3.15 kWh of solar power on a sunny day. This system was connected to KCP&L's SmartGrid enabling KCP&L to view and manage output from the panel. See Figure 3-24.
- Battery Storage. The battery backup could store up to 8 kWh of energy from the Solar PV system, which was discharged to offset energy use during peak demand. Stored energy and energy from the Solar PV system could also be sold back to the grid.
- Electric Vehicle Charging Station. The 110V Coulomb Technologies charging station complemented the overall theme of the SmartGrid experience. KCP&L installed 10 charging stations in the project area and another 11 throughout the metropolitan area.
- Energy Efficiency Programs. KCP&L showcased its full suite of energy efficiency programs to benefit customers.
- Weatherization. The demo house, built in 1911, contained exposed demonstrations of proper air sealing, insulation, window tightening and replacement.

Table 3-30: Demonstration House Literature

Title	Appendix
SmartGrid Demonstration House Fact Sheet	P.6.2.1
Demo Home Open House Invitation	P.6.2.2
Home Area Network Poster	P.6.2.3
Project Living Proof MEC Flyer	P.6.2.4
Project Living Proof Article	P.6.2.5
One-of-a-kind House Offers Ideas for a Green Life	P.6.2.6

Figure 3-24: Rooftop PV Installation on Project Living Proof Demonstration House

Figure 3-25: Sunverge Unit Installation at Project Living Proof Demonstration House

Hands-on training is often the most effective way to communicate with the target audience. As the lead sponsor of MEC's Project Living Proof, the SGDP was able to provide routine open hours for the public to visit the home and schedule tours for groups. The tours and open house hours were offered during weekdays and facilitated communication by allowing customers to touch, feel, interact with and learn about Smart Meters, in-home displays, home area networking, hyper-efficient appliances and a PEV charging station.

Table 3-31: Schedule of Demonstration House Tours

Audience	Date	Attendance
Mid-America Regulatory Conference Tour	June 8, 2010	~50
KCMO City Council and Key Staff	June 11, 2010	
Green Impact Zone Ombudsmen	Aug. 27, 2010	
Clean Energy Conference Attendees	Oct. 20, 2010	
KCP&L Board of Directors	Oct. 25, 2010	
Community Key Leaders	Mar. 10, 2011	
South Kansas City Chamber of Commerce	April 27, 2011	
Demonstration Home Grand Opening	April 30, 2011	
Martin City Middle School	June 03, 2011	
Kansas City Energy Future	Nov. 09, 2011	
Paseo High School Faculty and Staff	Feb. 17, 2012	
KCP&L Winning Culture Council	March 30, 2012	
Kansas State University Student	April 27, 2012	
KCP&L Iatan IDEAL Partners Team	April 30, 2012	
South Kansas City Chamber of Commerce	May 02, 2012	
MPSC Staff	June 26, 2012	
KCP&L Intern Program	June 29, 2012	
KCP&L Board Member (Dr. David L. Bodde)	July 19, 2012	1
SmartGrid Innovation Park Ribbon Cutting	Oct. 12, 2012	
CIGRE Conference Attendees	Oct. 30, 2012	
Halloween Open House	Oct. 31, 2012	
Grandview High School Green Tech Students	Nov. 07, 2012	
Paseo High School Students	Nov. 19, 2012	
UMKC E-Save Team	Nov. 19, 2012	
KS State Representative (Tom Sloan)	Nov. 28, 2012	1
Southtown Council's Leadership Tomorrow	March 27, 2013	
The Future of Energy – Communiversity Course	April 13, 2013	
MPSC Summer Interns	Aug. 01, 2013	12
Environmental Excellence Business Network (EEBN)	Sept. 12, 2013	
MPSC Staff	Oct. 25, 2013	8
KCP&L Generation Engineering	May 13, 2014	7
South Kansas City Chamber of Commerce Leadership	June 04, 2014	10
KCP&L New Engineers & Interns	June 04, 2014	8
MO PSC New Staff Orientation	July 11.2014	9
Burns & McDonnell Summer Interns	Aug. 05, 2014	40

Demonstration House Tours continue.

3.3.6.4 SmartGrid Innovation Park

The KCP&L SmartGrid Innovation Park, located north of KCP&L's Midtown Substation, represented an innovative and operational aggregation of smart grid technologies and provided a unique educational opportunity for the public.

A ribbon cutting ceremony was held on October 12, 2012 to open the Innovation Park to the public. The event was attended by Congressman Emanuel Cleaver II, KCP&L CEO Terry Bassham, and about 100 other community leaders and representatives, along with reporters.

"KCP&L is committed to this SGDP as a way to learn new ways to reduce electricity delivery costs, enhance reliability and make Kansas City smarter about energy," said President and CEO Terry Bassham. "But we also want to share what we are learning, and this park is a great way for all of our customers to come and learn more about the smart grid."

Figure 3-26 shows a layout of KCP&L's new Smart Grid Innovation Park where Park visitors can see how KCP&L is enhancing the electric grid in Kansas City's urban core by viewing:

- An informational kiosk that explained KCP&L's entire SGDP, including how power distribution is enhanced with smart grid technologies, the customer in-home experience, and the history of electric meters.
- A sophisticated, 1.0 MW-hour grid-connected lithium ion battery storage system, one of the largest of its kind in the country.
- A public EV charging station with dual level II ports.
- A ground-mounted 5.0 kW PV array, one of 9 project-funded PV arrays.
- A demonstration of KCP&L's new smart distribution management systems.

Figure 3-26: KCP&L's Smart Grid Innovation Park Site Layout

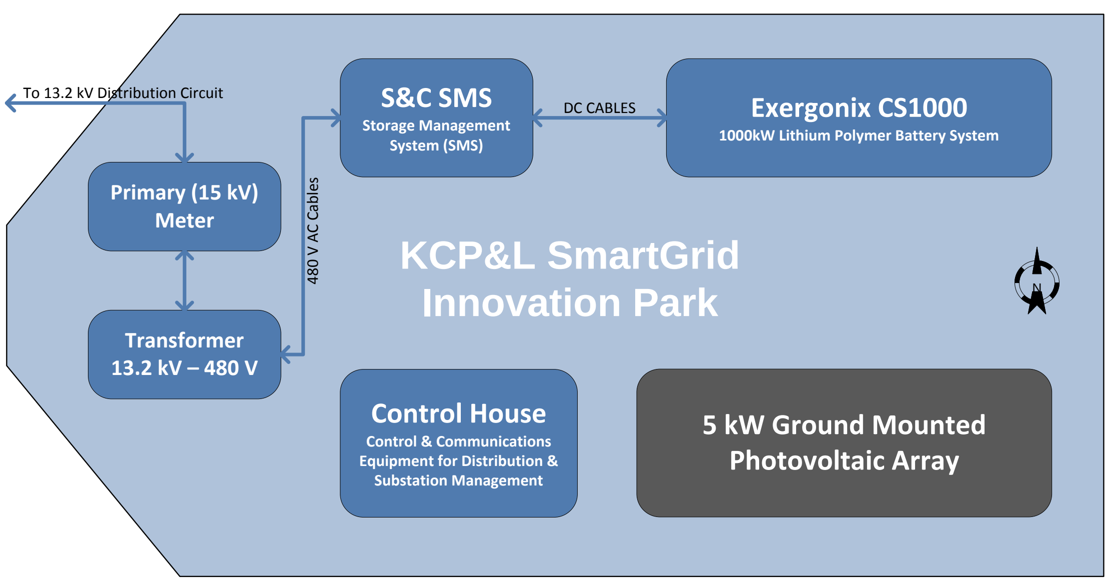


Figure 3-27: Battery Energy Storage System at SmartGrid Innovation Park

Figure 3-28: 5 kW Photovoltaic Array at SmartGrid Innovation Park

Figure 3-29: Informational Kiosk at SmartGrid Innovation Park

Table 3-32: Innovation Park Literature

Title	Appendix
Grand Opening Invitation	P.6.3.1
SmartGrid Innovation Park Booklet	P.6.3.2
EVSE Signs	P.6.3.3
Kiosk Pictures	P.6.3.4
SmartGrid Innovation Park Battery Wrap	P.6.3.5
SmartGrid Project Overview	P.6.3.6
Midtown Substation Upgrade	P.6.3.7
Substation Brochure	P.6.3.8

Hands-on training is often the most effective way to communicate with the target audience. Tours and field demonstrations at the Innovation Park provided an opportunity for the industry experts as well as the general public to get a first-hand look at SmartGrid possibilities. The tours included a trip through the SmartGrid Innovation Park, where participants were able to walk inside a grid-connected battery; touch a solar generation installation and electric vehicle charging station; and see a demonstration of the DMS and DCADA control systems associated with the SGDP.

Table 3-33: Schedule of SmartGrid Innovation Park Events

Tour	Date
KCP&L Board Member (Dr. David L. Bodde) Tour	July 19, 2012
SmartGrid Innovation Park Ribbon Cutting Tours	Oct. 12, 2012
KCP&L DMS Team Tour	Oct. 12, 2012
CIGRE Conference Attendees Tour	Oct. 30, 2012
KCP&L Executive Management Tour	Nov. 27, 2012
KS State Representative (Tom Sloan) Tour	Nov. 28, 2012
Cerner Corporation Tour	Dec. 6, 2012
Mid-Central Utilities Telecom Council	March 26, 2013
MPSC Summer Interns Tour	Aug. 1, 2013
Environmental Excellence Business Network (EEBN) Tour	Sept. 12, 2013
MPSC Staff Tour	Oct. 25, 2013
KCP&L Generation Engineering	May 13, 2014
South Kansas City Chamber of Commerce Leadership	June 04,2014
KCP&L New Engineers & Interns	June 04/2014
MO PSC New Staff Orientation	July 11, 2014
Burns & McDonnell Summer Interns	Aug. 05, 2014
UMKC Power Electronics Class (ECE-436)	Nov. 24, 2014

Innovation Park tours continue

3.4 Operational Demonstration and Testing Results

The KCP&L project has been divided into five subprojects to demonstrate the deployed SmartGrid technologies and applications that enable specific DOE-defined Smart Grid Functions. Table 3-34 lists all 23 Demonstration Applications, the SmartGrid Function they support, and the subprojects deploying each application.

This section contains an overview of each Smart Grid Function supported by the Demonstration Applications and a description of potential benefits from each enabled Smart Grid Function. For each Demonstration Application, an Operational Demonstration Test Plan was developed that includes descriptions of the technology that would be applied, a description of expected results, relevant impact metrics, data to be collected and analyzed, and the benefit analysis method that would be used.

Table 3-34: KCP&L Operational Demonstrations/Tests

Smart Grid Project Application Demonstrations/Tests T = Technology Demonstration Only B = Operational Benefit Test s = Supporting Subproject		Demonstration Subproject				
Smart Grid Function	Application	Smart Metering	Smart End-Use	Smart Substation	Smart Distribution	Smart Generation
Automated Voltage & VAR Control	Integrated Volt/VAR Management (VVC)	s		s	B	
Real-Time Load Transfer	Feeder Load Transfer (FLT)	s		s	B	
Automated Feeder & Line Switching	Fault Isolation & Service Restoration (FISR)			s	B	
Automated Islanding & Reconnection	Feeder Islanding with Grid Battery			s	s	T
Diagnosis and Notification of Equipment Condition	Substation Protection Automation			T		
	Asset Condition Monitoring			B	B	
	Hierarchical Control (DCADA)			T	T	
Real-Time Load Measurement and Management	Automated Meter Reading (AMR)	B				
	Remote Meter Disconnect/Re-Connect	B				
	Meter Outage Restoration w/PSV (PSV)	T			T	
	Demand Response Events (DR)	T	s			T
Customer Electricity Use Optimization	Historical Interval Usage Information (HEMP)	s	B			
	In-Home Display (IHD)	s	B			
	Home Area Network (HAN)	s	B			
	Time-of-Use Rate (TOU)	B	B			
Distributed Production of Electricity	Distributed Rooftop Solar Generation					B
Storing Electricity for Later Use	Electric Energy Time Shift					B
	Electric Supply Capacity				s	B
	T&D Upgrade Deferral				s	B
	Time of use Energy Cost Mgmt.		B			
	Electric Service Reliability		B			
	Renewable Energy Time Shift		B			
	PEV Charging					B

3.4.1 Automated Voltage and VAR Control

Automated VVC requires coordinated operation of reactive power resources such as capacitor banks, voltage regulators, transformer load-tap changers, and DG with sensors, controls, and communications systems. These devices could operate autonomously in response to local events or in response to signals from a central control system.

3.4.1.1 Integrated Volt/VAR Management

Integrated Volt/VAR Management is a demonstration of one aspect of the Automated Voltage and VAR Control function.

3.4.1.1.1 Overview

The following sections provide an overview of the operational, demonstration, testing, and evaluation methodology used for the Integrated Volt/VAR Management operational demonstration.

3.4.1.1.1.1 Description

KCP&L currently has a very active capacitor deployment and automation program, in which each capacitor operates autonomously in response to local conditions to satisfy the circuit operating (voltage and power factor) criteria. This VVC operational test compared the operational performance of the SmartGrid Automated VVC program relative to the existing KCP&L capacitor program controls.

The SmartGrid Automated VVC function extends the legacy KCP&L VVC design parameters to include losses and objective functions. The four objective functions are to:

- Minimize the sum of power losses
- Minimize the power demand
- Maximize the substation transformer reactive power
- Maximize the difference between energy sales and energy cost

The SmartGrid Automated VVC program continuously monitors circuit conditions, uses a distribution power flow to calculate circuit voltage profile and losses; and centrally controls power transformer load tap changer (LTC) position, voltage regulators, and switchable capacitors to meet the prescribed objective functions.

3.4.1.1.1.2 Expected Results

This operational demonstration was expected to yield the following:

- For each objective function, KCP&L expected to see an incremental improvement in circuit operational performance indicators including:
  - Voltage profile
  - Power factor at circuit head
  - Electrical losses
  - Economics
- Based on the circuit performance improvements obtained under each VVC objective function, a recommended objective function would be selected for sustained operation of the SmartGrid Demonstration Circuits.
- Due to KCP&L's active capacitor deployment & automation program, a significant improvement might not be achievable.
- An overall 1-3% reduction in active power consumption would be expected on the VVC controlled feeders or transformer.

3.4.1.1.1.3 Benefit Analysis Method/Factors

The DOE SGCT was used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits were quantified.

- Reduced Electricity Losses
- Deferred Generation Capacity Investments
- Optimized Generator Operation /Reduced Electricity Consumption/Cost

Benefits were calculated using SGCT formulas. The following factors were measured, projected or calculated during the application operation and/or demonstration.

Reduced Electricity Losses

- Distribution Feeder Load (MW)
- Distribution Feeder Losses (MWh) (base & project)
- Distribution Losses (%) (base & project)

Deferred Generation Capacity Investment

- Reduced Total Customer Peak Demand (MW)

Deferred Distribution Capacity Investment

- Capital Carrying Charge of Distribution Upgrade($/yr)
- Distribution Investment Time Deferred (yrs)

Optimized Generator Operation/Reduced Energy Costs (Consumer)

- Annual Generation Costs (Avoided)
- Reduced Total Annual Electric Consumption (kWh) by customer class.

Reduced CO_2, SOx, NOx and $PM_{2.5}$ Emissions

- Annual Distributed Generation Production (MWh)

3.4.1.1.1.4 Testing Methodology

The following points provide an overview of how the operational demonstration and testing for this application was accomplished:

- Testing for the major objective function (CVR – Conservation Voltage Reduction) was done on a day-on/day-off basis, to compare current legacy protection schemes to one of the central control objectives of the Volt/VAR Control DMS application.
- Testing for the secondary objective (DVC – Dynamic Voltage conservation or notch objective) was done on an hourly basis (notch) where VVC was called upon for a couple of hours on a Friday.
- Individual seasonal testing and data collection periods were established as possible.
- During each test period, the DMS and VVC operational parameters were adjusted to maximize potential benefits achievable for the objective control function being tested.
- DMS collected voltage profile data and power data for all SCADA-enabled equipment and the AMI collected under/over voltage alarms from customer AMI meters.

3.4.1.1.1.5 Analytical Methodology

The following points provide an overview of the analytical methods that were used to evaluate the impact and benefits of this application:

- The voltage and power data for an operational period (on or DVC day) and a normal period (off day, not implemented) were compared and analyzed. Matching periods were identified using a broad set of parameters to see that the loads, temperatures, and circuit configurations on periods were similar in nature.

- For each operational period, the matching off day was used as baseline data to determine a quantified impact (overall reduction, peak load reduction, etc.).
- DMS voltage for on/off days was used to determine the quantified impact on circuit voltage profile.

3.4.1.1.2 Plan Execution and Analysis

The following sections provide details regarding the functional tests performed, data collection and analysis performed for the Integrated Volt/VAR Management operational demonstration.

3.4.1.1.2.1 Demonstration Overview

The VVC program could be broadly divided into three major phases: the planning/pretest phase, the test/implementation phase, and the analysis phase. A number of challenges presented throughout the program — the small size of the KCP&L SmartGrid area, its considerable number of outages, a lack of automation on all feeders on a transformer, a small scale DMS that was not integrated with the AMI system, and parallel implementation of other SmartGrid programs within the small area — drove the need for extensive planning and analysis.

The first phase consisted of identifying the correct test procedures, schedules, parameters, evaluation methods, and, later on, fine-tuning these procedures and parameters during the pretest phase (2 weeks prior to implementation). The planning phase also involved substantial testing to see that VVC could be implemented on the system. The team and DMS vendor made a number of modifications to provide readiness for the implementation phase.

The implementation phase consisted of actually running the VVC program as per the schedule and the test procedures established. A number of manual procedures had to be introduced to confirm that system parameters were within limits. As confidence rose in the program, a number of manual procedures (manual AMI pings, major customer notifications, overnight monitoring) were discarded. State estimator results, AMI voltages, and other system data could not be automatically captured and the actual VVC application had to be manually enabled and disabled. Lack of AMI integration generated the need for intelligent manual intervention in changing the parameters on the application, based upon loading of the feeders.

The analysis phase involved extracting data from the DMS historian and performing extensive data manipulation to identify the improvements from VVC. The DMS historian proved inadequate for manipulating data and for large data extractions. Raw data had to be extracted and meticulously analyzed to identify the on-day/off-day matches and the improvements of VVC. In terms of data points, more than 5 million rows were handled during the VVC period.

VVC Functionality

Traditionally, voltage has been controlled at the head of the feeder by changes at the tap changer or regulator by estimating the voltage at the remainder of the feeder. Addition of automated cap banks and other voltage control devices along the feeder have slightly improved voltage/VAR control. The VVC application (used for the KCP&L VVC program) on a DMS takes it a step ahead and provides a centralized solution that utilizes both tap changers at the head of the feeder and cap banks along the feeder to control the voltage and VAR flow. The centralized application also utilizes any additional resources on the feeder (reclosers etc.) with monitoring capabilities to accurately estimate the voltage and power flow all along the feeder.

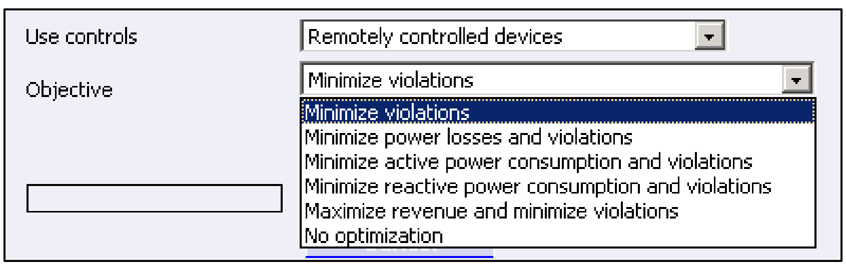
The VVC application dynamically controls the voltage by utilizing the control and monitoring assets at the same time. The application is fed data from a state estimator application that is run every 15 minutes, or whenever a major system change (system configuration or a large change in measured values) occurs, thus enabling real-time dynamic voltage control. This real-time data from the state estimator increases efficiency of the application when compared to traditional voltage control methods.

The primary assets of the VVC implementation at KCP&L are the tap changers on the substation transformer and the automated cap banks on the SGDP feeders. There are additional monitoring devices (reclosers, cap banks) and automated devices (cap banks) on the feeder that were used by the application to further optimize power flow, thereby stabilizing voltage and achieving maximum reduction in voltage with a flattening of the voltage profile within specified limits all along the feeder. The manual monitoring assets on the feeder are the AMI meters installed at the customer. A manual ping on a web application generates the voltage and current data instantaneously for a meter, but each meter requires to be pinged individually.

VVC Operational Settings

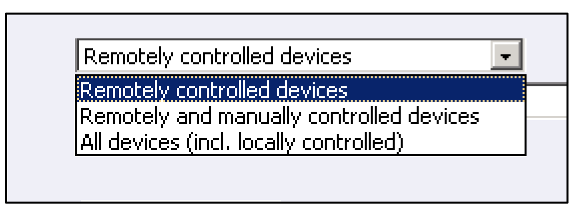
The VVC program utilized the VVC application from the Siemens DMS application suite. The operating modes and objective functions of the application were tested during the pretest phase to identify optimum modes to implement CVR and to mimic KCP&L's DVC program. Objectives options of the VVC application are shown in Figure 3-30.

Figure 3-30: VVC Application Objectives



The closed loop mode was used for all testing as this required lesser manual intervention with VVC executing the switching operations without any user intervention. The "Minimize active power consumption and violations" objective function for the VVC application was used to implement CVR, as a decrease in voltage was essential for a decrease in active power. Figure 3-31 below shows the different control configurations for VVC; only remotely controllable devices were used.

Figure 3-31: VVC Application Asset Options



As shown in Table 3-35, VVC was operated under two different modes over the course of the test period. Each mode consisted of an objective function, along with additional settings and conditions to maximize the impact. The different modes also simplified comparisons with KCP&L's existing control schemes; each mode and its operating conditions are shown in the table.

Table 3-35: VVC Program Modes

Mode	Objective Function	Open/ Closed	Assets	Time Period
CVR	Minimize active power consumption	Closed	LTC, Caps	Alternating ON Days (Mon-Thu) over 4 months
DVC	Minimize active power consumption	Closed	LTC, Caps	Notch Days (Fri) over 4 months

VVC Implementation Area

The VVC program was implemented in a small portion of the SmartGrid area. It involved a single transformer, the substation's newest one and the one with the most automated feeders installed. The transformer fed eight feeders, including three fully automated with AMI meters and another feeder with AMI meters installed. The VVC application can control the tap changer at the substation transformer and all the VVC assets on the automated feeders as mentioned earlier. The voltage would be controlled on all feeders as a result of tap changes but stabilized further using cap banks only on the automated feeders.

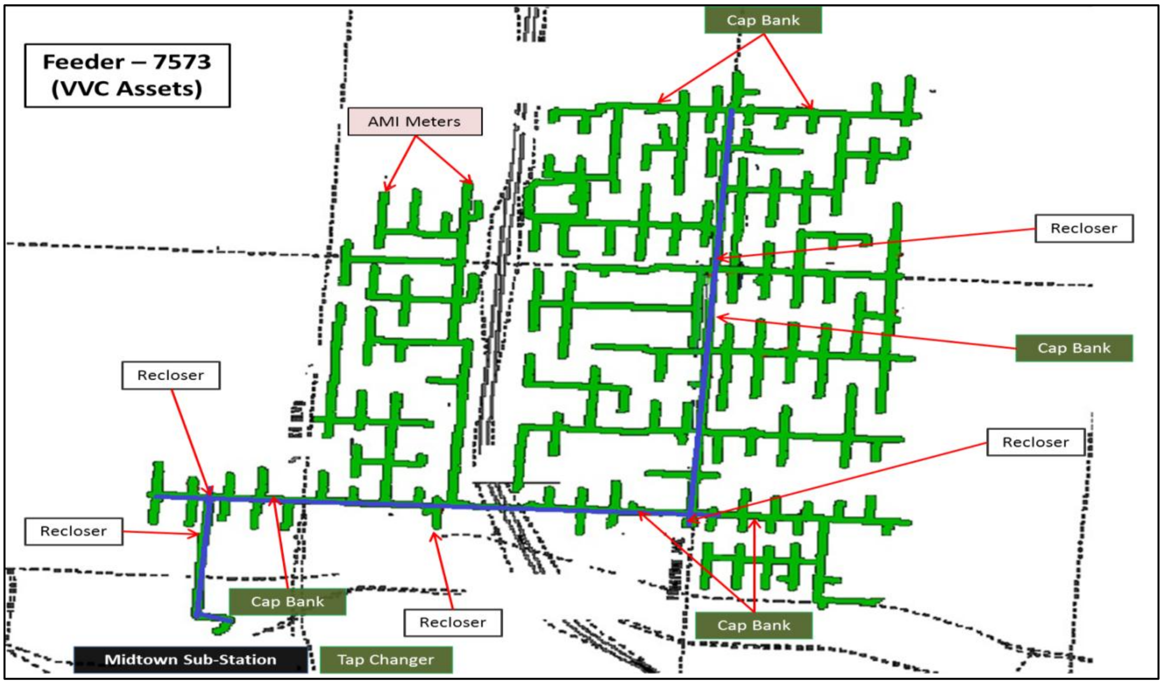
- VVC was implemented in different modes during the summer of 2014. Though originally planned to be implemented for longer periods, the relative size and implementation of the project and testing of numerous applications and regular circuit reconfigurations limited time available for testing.
- Testing was conducted on a full day (on-day/off-day) basis or an hourly (notch) basis to compare the current legacy voltage and VAR schemes with the advanced centralized control of the VVC application. The test days are briefly described below; testing was conducted on weekdays with alternating on days/off days Mondays through Thursdays, and with notch days Fridays.
  - Off days: The VVC assets shall operate under the existing local control schemes.
  - On days: VVC will be implemented for 24 hours with local control disabled.
  - Notch days: VVC will be implemented for 2 hours during which local control will be disabled, with local control enabled for the rest of the day.

Figure 3-32 displays the one-line screenshot for the feeder 7573 from the DMS, with locations of VVC assets highlighted all along the feeder. It is one of the six highly automated feeders in the SmartGrid area. The tap changer in the substation serves as the major asset in reducing the voltage on the feeders for CVR and notch testing. The cap bank and the tap changers are then used for further reduction and stabilizing the voltage all along the feeder.

It must be noted that AMI meters are located on all the customer meters along the feeder but only a small number of specific AMI meters were utilized to monitor voltage on the feeder. This will be explained in subsequent sections. While locations of only a couple of AMI meters in the feeder are shown below, a larger number of AMI meters were identified and monitored to record the voltage at the customer.

The centralized state estimator uses the data provided by the tap changer, feeder breakers, recloser, and cap banks to accurately estimate the voltage and power along the feeder. This data is used by the VVC application to further control the voltage and reactive power by using the tap changers and cap banks. The state estimator is run for each solution provided by VVC to validate the solution, thus ensuring that a comprehensive centralized solution that uses the data from the entire system is generated by VVC.

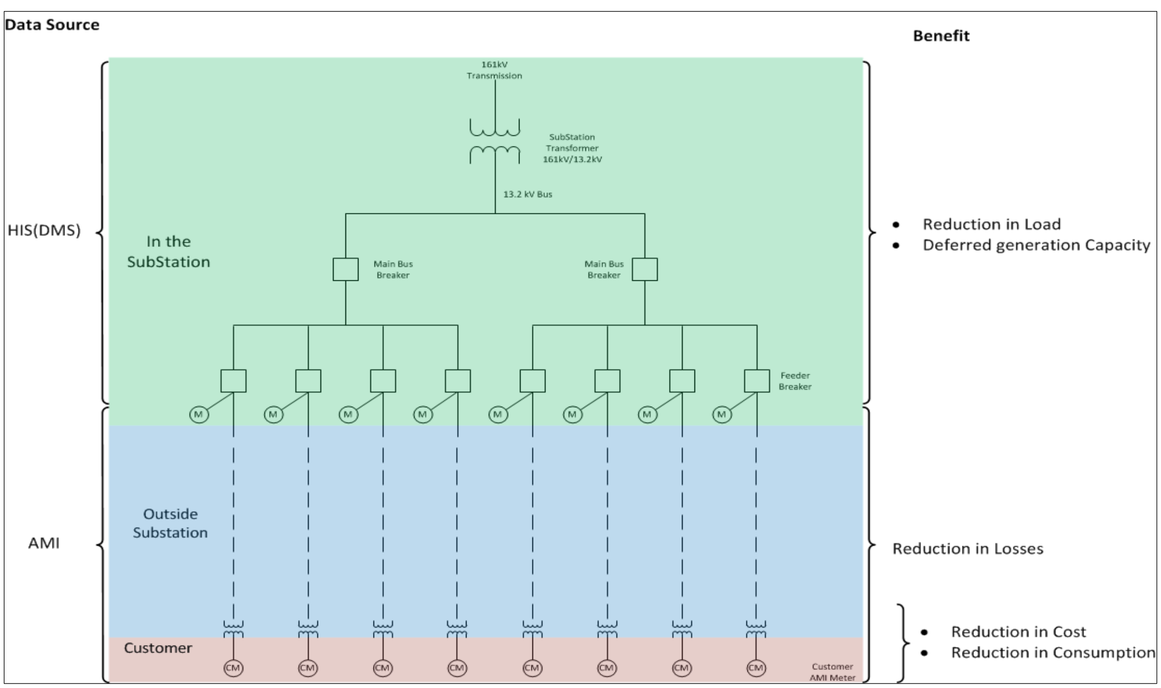
Figure 3-32: Feeder 7573 DMS One-Line Diagram



VVC Data Capture and Analysis

A major part of the VVC program was the analysis phase for determining the impacts of VVC. The analysis required data from across the distribution system. A majority of the data used for analysis was extracted from the historian on the DMS but additional data to evaluate customer benefits was extracted from the AMI system. The data source and corresponding benefit correlation is shown below in Figure 3-33. The figure highlights the entire distribution system, from the substation transformer up to the customer meter and the data source for capturing data at each level.

Figure 3-33: VVC Data Source – Benefit Correlation



<u>VVC Application Limits and AMI Monitoring</u>

The KCP&L VVC analysis was primarily focused on reducing the active power consumed by the load. Traditionally, lack of monitoring capabilities outside of the substation and tight voltage requirements require the utility to use a safe approach and supply power to the customer at a voltage that is well within the limits and generally on the higher side. A higher voltage results in a higher consumption of active power by the load. New Volt/VAR technologies — with advanced state estimation, AMI metering, and additional monitoring on the power system beyond the substation — enable the utility to take a more aggressive approach and supply the customer at a lower voltage while staying within standard voltage requirements. The modes mentioned above have the primary aim of reducing voltage across the distribution system while still keeping the customer voltage within limits.

The AMI meter voltages were not configured to automatically feed into the DMS system and were not monitored by the VVC application. The VVC application controlled measured voltages and calculated voltages within the set standards limits (shown below in Figure 3-34) at all the nodes and measuring devices in the DMS. The DMS though only contained distribution data up to the primary of the LV transformer; the DMS, for example, contained only M-level data.

Figure 3-34: VVC Voltage Limit and Penalty Setting

	High Voltage limit [p.u.]		Low Voltage limit [p.u.]		Overload limit [p.u.]	
	Min	Max	Min	Max	Transformer	Line
Long	0.95	1.05	0.95	1.05	1.0	1.0
Medium	0.92	1.08	0.92	1.08	1.2	1.0
Short	0.8	1.12	0.8	1.12	1.4	1.0

	Voltage deviation penalty		Overload penalty		Power factor violations	
	High	Low	Line	Transformer	Limit	Penalty
Long	10.0	10.0	1.0E-4	1.0E-4	0.95	1.0
Medium	1000.0	1000.0	0.01	0.01	0.87	3.0
Short	100000.0	100000.0	1.0	1.0	0.8	10.0

This lack of LV data in the DMS required the AMI meters to be monitored separately to see that the customer voltages were well within limits, as voltage drop in secondary circuit is a major part of the drop in voltage from the substation up to the customer. But the AMI meters could not be monitored on a system wide basis and each meter had to be manually pinged to monitor the voltage on a specific meter. Monitoring the thousands of meters on a daily basis was not feasible and a more pragmatic analytical approach was taken.

Meters that were on long limbs of a feeder, far away from the LV transformer — i.e., containing long secondaries and being the farthest from the source — were identified and pinged on a regular basis. State estimation data was analyzed and LV transformers with the lowest source voltage were identified and meters on these transformers were pinged. Over the testing period, meters with voltages consistently on the lower side were identified and monitored to see that customer voltages were within the standard limits.

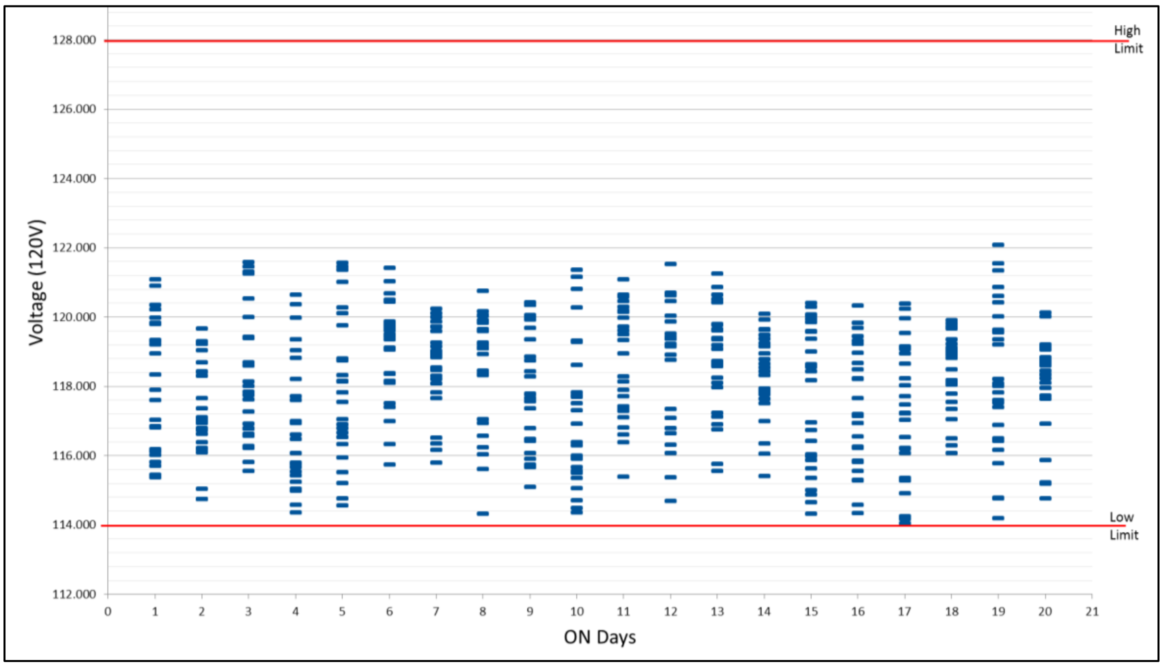
A particularly challenging aspect of the implementation was estimating and setting the limits on the VVC application for the MV level by observing the voltages on the LV level. A major factor was the loading level, as voltage drop in the secondary level increased drastically as the load increased. During the pretest phase and throughout the testing period, the team was able to accurately estimate the voltage limits with fewer AMI pings. This saved a considerable amount of time, as compiling AMI data manually took multiple hours in a day.

Figure 3-35 displays a plot of all the AMI voltage pings across the ON days of the VVC program. The voltages, though on the lower side as expected from VVC, were within limit. Because these voltage pings are for the worst-case meters on the system, results on the lower side are expected. The remainder of the meters had voltages that were well within limits. Rectifying some of these worst-case meters and providing lesser drop could have allowed a further reduction in voltage.

3.4.1.1.2.2 Energy Reduction Achieved from CVR Mode

Conservation voltage reduction involves the reduction of normal active power consumption by reducing the voltage within standard. The CVR mode for KCP&L's VVC implementation was designed to reduce the load on the system for a continuous period (24 hours). The actual reduction in active power consumption achieved as a result of voltage reduction is identified by comparing the active power on an on day to a matching off day.

Figure 3-35: AMI Meter Voltages



On/Off Day Comparison

The on/off day approach essentially looks at each day individually, rather than as a clump of days (as in a seasonal or monthly approach), to identify benefits from VVC. The aim is to find a baseline day where VVC was not implemented, and a baseline for a day on which VVC was implemented. The baseline day for an on day could be any of the off days with the same load, temperature and other characteristics such as the on day. A number of these factors were used to determine an accurate baseline off day for an on day. The major criteria to establish a baseline day were temperature and active power. Absolute temperature values were compared. In the case of active power as it would be reduced on an on day, a regression technique that compares the variation in load was used rather than comparing the absolute values. Similar techniques were used to compare temperature variations to further narrow down the baseline day. The comparison factors are listed below in order of priority:

- Average Daily Temperature — The average daily temperature for a baseline day must be within one degree for an on or notch test day.

- Temperature Variations (R^2 Method) — The hourly temperatures for the on and off days shall be compared to ensure that the variations in temperature on the test day and the baseline day are similar. The coefficient of determination, or R2 method, was used to determine that the variations in temperature were within 90% of each other.
- Weekdays — Weekdays shall be primarily used as mentioned before, with weekend days used as the last resort provided that the rest of the conditions are met.
- Real Power Variations (R^2 Method) — The 60-minute variations in real power for an off day must be within 90% of the variations during an on day. The coefficient of determination must be greater than 0.90 between the real power on the two days.
- Reasonability — Additional limits were set for some of the other factors such as active power reduction (<5%) in a day and CVRf (<3) to ensure that abnormal values were excluded from the final analysis.
- Waveforms — Active power and voltage for the probable on-off matches from the above criteria were plotted and analyzed. Any waveforms with anomalies that could cause the reduction rather than VVC, or with abnormal characteristics observed exclusively on either the on or off day, were eliminated from the match data.

VVC, when implemented for CVR, was expected to reduce voltage at the transformer and also similarly manage voltage along the feeder using cap banks to maintain a much flatter voltage profile on the feeders. This section shall discuss, in detail, the reduction in voltage achieved during an entire day, and outline benefits (active power reduction) achieved by that reduction.

Table 3-36 lists the matching on/off days and the respective reduction in voltage achieved for each match.

Table 3-36: On-Off Match Data – Voltage Reduction

On Day	Off Day	Voltage Reduction (%)
7/15/2014	7/16/2014	1.689
7/17/2014	8/12/2014	1.581
7/29/2014	8/14/2014	1.381
8/13/2014	7/30/2014	1.783
8/13/2014	9/30/2014	1.802
8/13/2014	5/26/2014	1.787
9/29/2014	7/30/2014	2.476
10/7/2014	10/6/2014	2.221
10/15/2014	10/20/2014	2.792
10/21/2014	10/6/2014	2.184
10/21/2014	10/8/2014	2.198
10/21/2014	10/20/2014	2.694
Overall		**2.049**

In the SmartGrid area, reduction ranged from 1.38% to 2.79%. The type of feeder, variations in daily load, and time of year affected the capability of VVC to reduce the voltage. Overall an average reduction of 2.05% was achieved during the testing period, primarily during a mild summer. AMI data was not utilized by VVC and voltage limits were set for the medium voltage section of the distribution system. Therefore, a conservative approach was taken initially to safely estimate the voltage drop and the limits were reduced as user confidence increased in the ability for the system to maintain voltage within limits at the meter without AMI data. The static voltage limits set on the application also did not consider the loading of the feeder. It was observed that as the load increased the voltage drop on the low-voltage sections also increased, thereby necessitating a more conservative voltage limit at the primary (13.2 kV) level. Conversely, during low-load periods the voltage drop on the low-voltage sections was negligible and the voltage limits on the primary level could be dropped lower.

The reduction in voltage achieved is highlighted in Figure 3-36, displaying voltage at the substation bus and at the end of line recloser for a full week of VVC implementation. The week includes two on days, two off days and a notch day in this sequence: off, on, off, on, notch. The on (CVR) days demonstrated a clear decrease in voltage when compared to adjacent on days. Similarly, the notch (DVC) day showed a distinct period of time with a sharp decrease in voltage and increase back to normal once DVC had been turned off. In this case the voltage limit for VVC application was set at 118.7 V or 7.53 kV, denoted by the red line on the graph. VVC ensured that the voltage was consistently above the limit in CVR mode.

The application accounts for all nodes at the medium-voltage level, and, where measured values were not available, used values calculated from the state estimator. The lower limit set on the VVC application applies for these nodes as well. In Figure 3-36, there is a slight gap between the voltage levels during an on day and the lower limit. This gap accounts for additional voltage drop on the feeder laterals where specific nodes could see a voltage lower than the end-of-line recloser. Voltages at these laterals are calculated values that cannot be captured on a regular basis and could not be plotted.

Figure 3-36: Bus Voltage and End of Line Recloser Voltage (Full VVC Week 07/14 – 07/18)

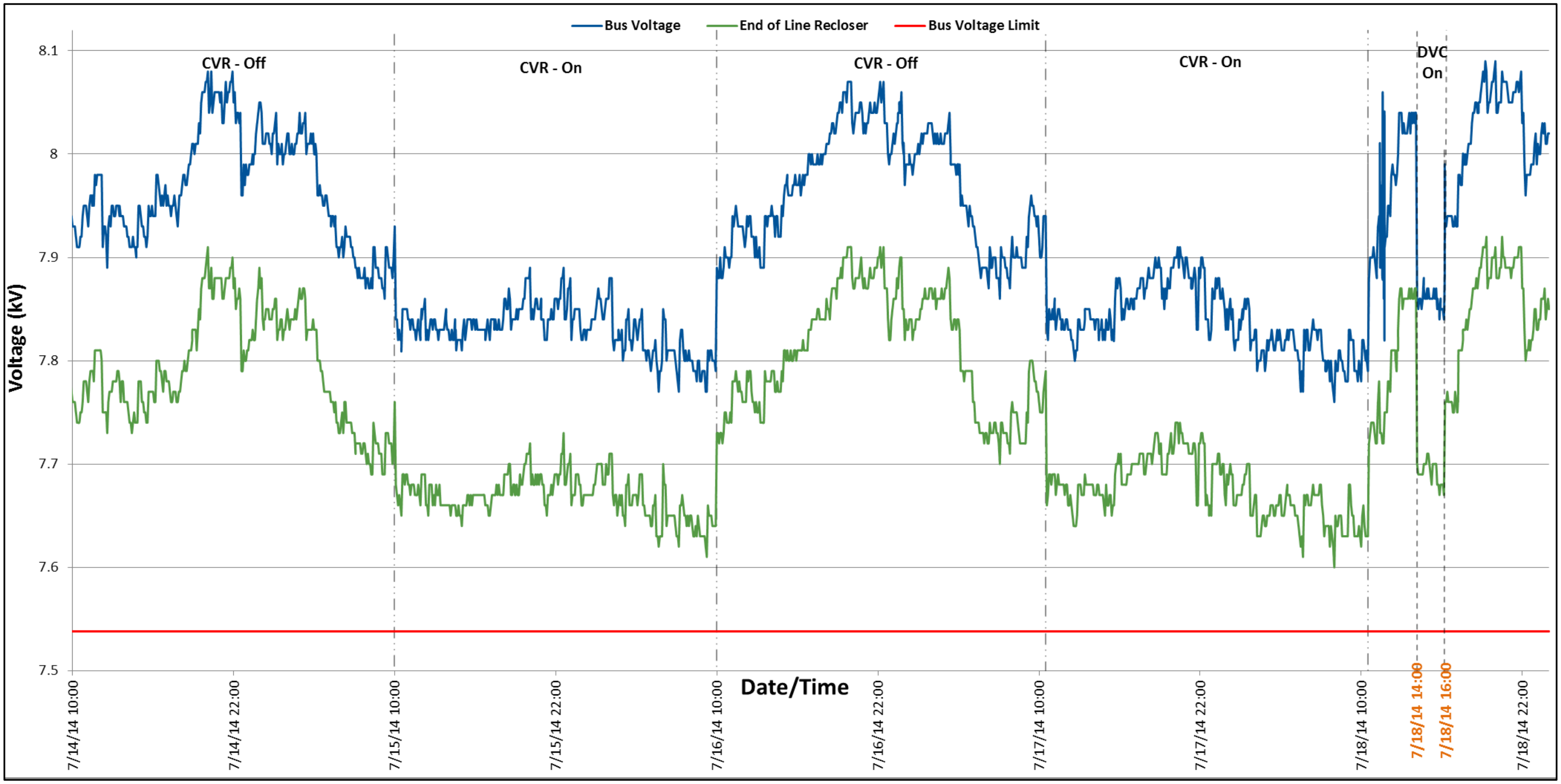


Figure 3-37 displays the reduction in voltage achieved during an on (07/15) day compared to an off (07/16) day. For the on day, voltage clearly dipped after the start and maintained the lower level for a period of 24 hours, provided the VVC was on; then, within 5 minutes of stoppage, voltage returned to normal levels. The overall reduction in voltage achieved for this on-off day match was 1.689%.

Figure 3-37: 7/15 to 7/16 Voltage Comparison

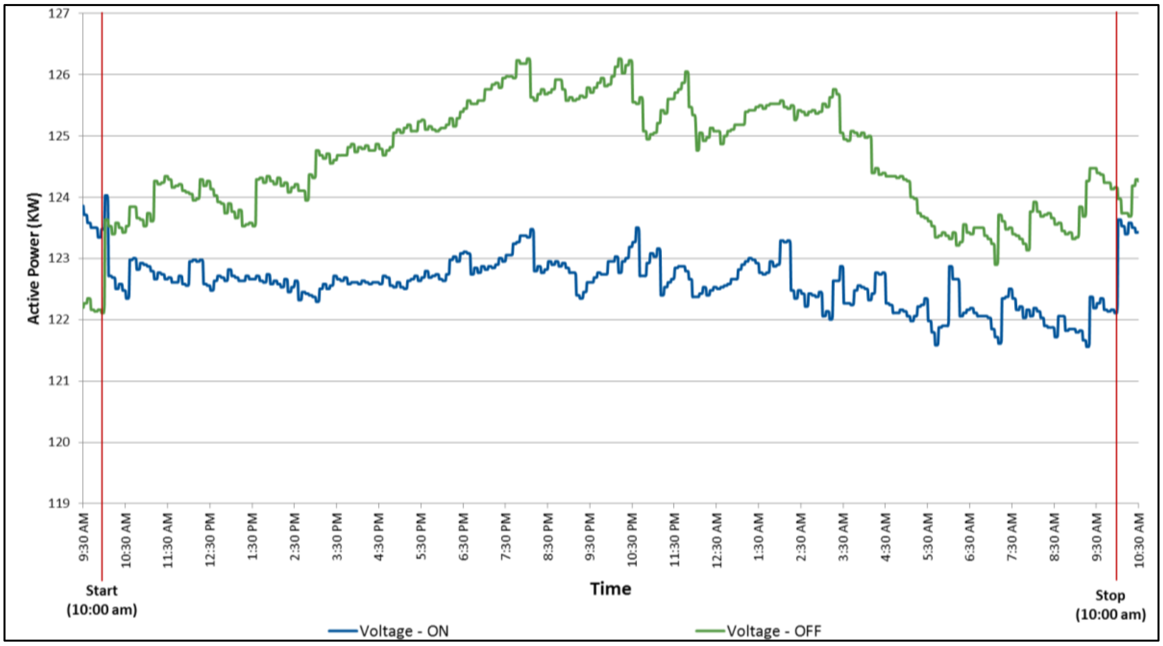


Figure 3-38 displays the active power variation for the same on-off. For most of the day, active power consumed is slightly lower than that of the off day most of the day — a result of the reduction in voltage across the system. The reduction generates a proportionate reduction in active power consumed by the customers.

Figure 3-38: 7/15 to 7/16 Active Power Comparison

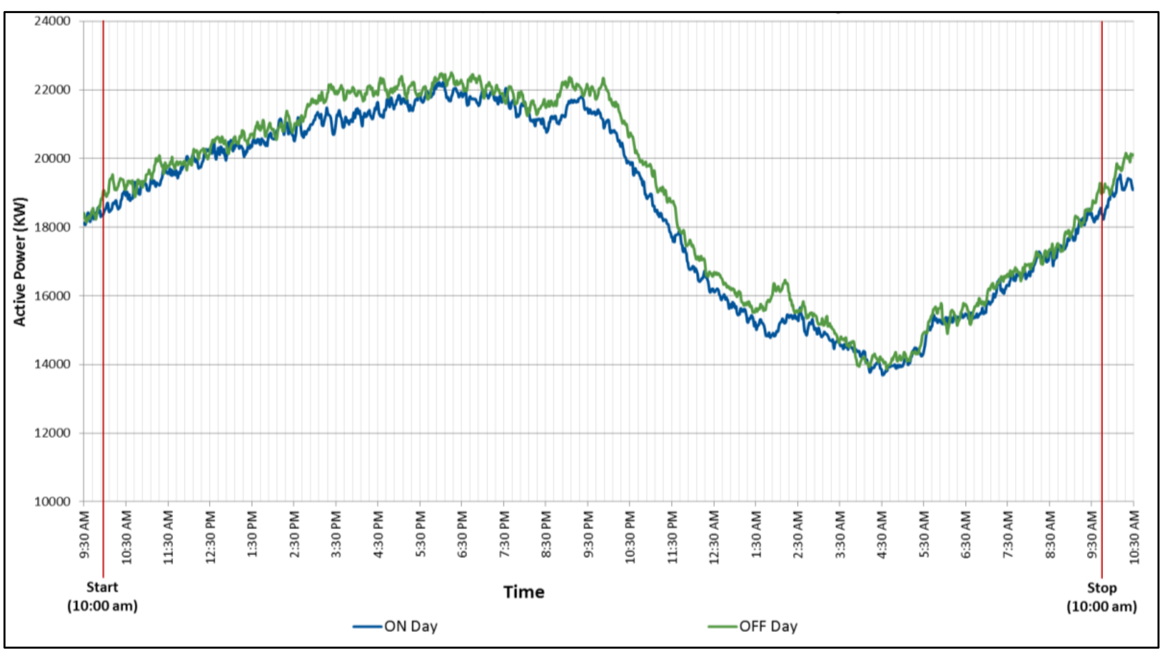


Table 3-37 shows the active power data for all on/off matches during the testing period. As discussed before, any matches with anomalies, or large reduction or increase in active power (other than the predetermined requirement for matches) were excluded. For all the matches, a consistent decrease in active power as a result of decrease in voltage was observed. The table also shows the corresponding voltage reduction and CVRf for each match. The CVRf is the ratio of kW reduction to voltage reduction and is generally a powerful parameter in determining the effectiveness of CVR. An overall CVRf ranging from 0.4 to 1.0 reflects impact from CVR on the active power reduction for the match data with minimal disturbance from other factors. A very high or very low CVRf generally reflects impact of factors other than CVR.

Table 3-37: On-Off Match Data

On Day	Off Day	KW Reduction (%)	Voltage Reduction (%)	CVRf
7/15/2014	7/16/2014	1.996	1.689	1.182
7/17/2014	8/12/2014	3.277	1.581	2.073
7/29/2014	8/14/2014	2.097	1.381	1.518
8/13/2014	7/30/2014	0.857	1.783	0.481
8/13/2014	9/30/2014	3.513	1.802	1.950
8/13/2014	5/26/2014	1.452	1.787	0.812
9/29/2014	7/30/2014	0.776	2.476	0.314
10/7/2014	10/6/2014	0.311	2.221	0.140
10/15/2014	10/20/2014	1.267	2.792	0.454
10/21/2014	10/6/2014	0.717	2.184	0.328
10/21/2014	10/8/2014	2.071	2.198	0.942
10/21/2014	10/20/2014	1.266	2.694	0.470
Overall		**1.633**	**2.049**	**0.889**

The overall reduction in active power consumption that could be achieved — by using automated cap banks and tap changers, incorporating them into a DMS, and managing through a central DMS application for the KCP&L system — was 1.63%. Note that the voltage reduction achieved during this CVR implementation was only 2.049%. The SmartGrid area consisted of short urban feeders, and all feeders on the transformer used for CVR were not automated. The AMI system was also not integrated into the DMS or the Volt/VAR application. The narrow scope of the project, and vast number of SmartGrid technologies implemented, prevented additional testing and optimization of load for VVC. Having a small number of customers on each feeder prevented the voltage from being reduced further. Smart reconfiguration, maintenance, or cable replacement for these customers could have reduced their associated voltage drop and enabled VVC to further reduce voltage on the feeder within the limits.

There were certain cases observed wherein the matches qualified for all criteria but the graphs showed small anomalies that could have caused the reduction in kW during the on day. The transformer used for CVR fed two main buses and, in some cases, anomalies at the bus level canceled each other and resulted in a good match at the transformer level. Further analysis of the active power plots at the bus level showed the anomalies, which were excluded from the matches. Figure 3-39, Figure 3-40, and Figure 3-41 show the active power and voltage plot at the transformer level and at the bus level (Bus #7 and Bus #8) for the same match as discussed above. A reduction in voltage as a result of VVC, and a slight decrease in active power consumption, is shown throughout the day and in each figure.

Figure 3-39: TF #7/8 Active Power & Voltage Comparison (07/15 – 07/16)

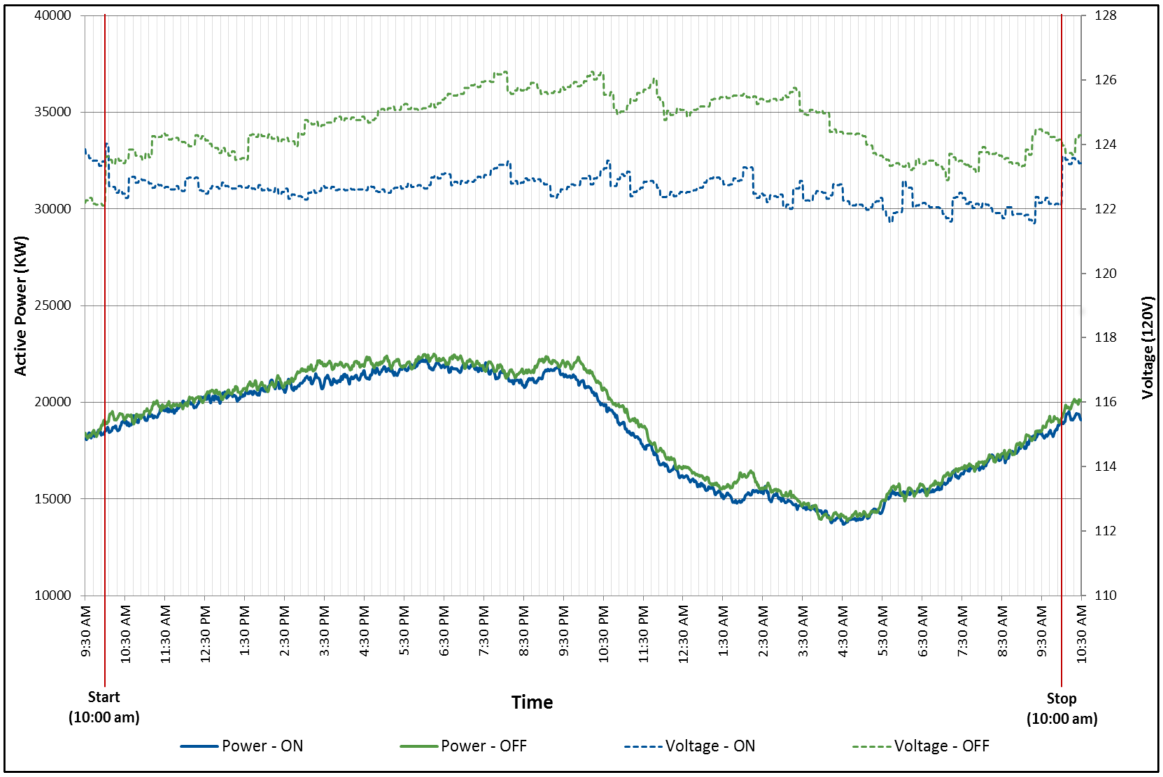


Figure 3-40: Bus #7 Active Power & Voltage Comparison (07/15 – 07/16)

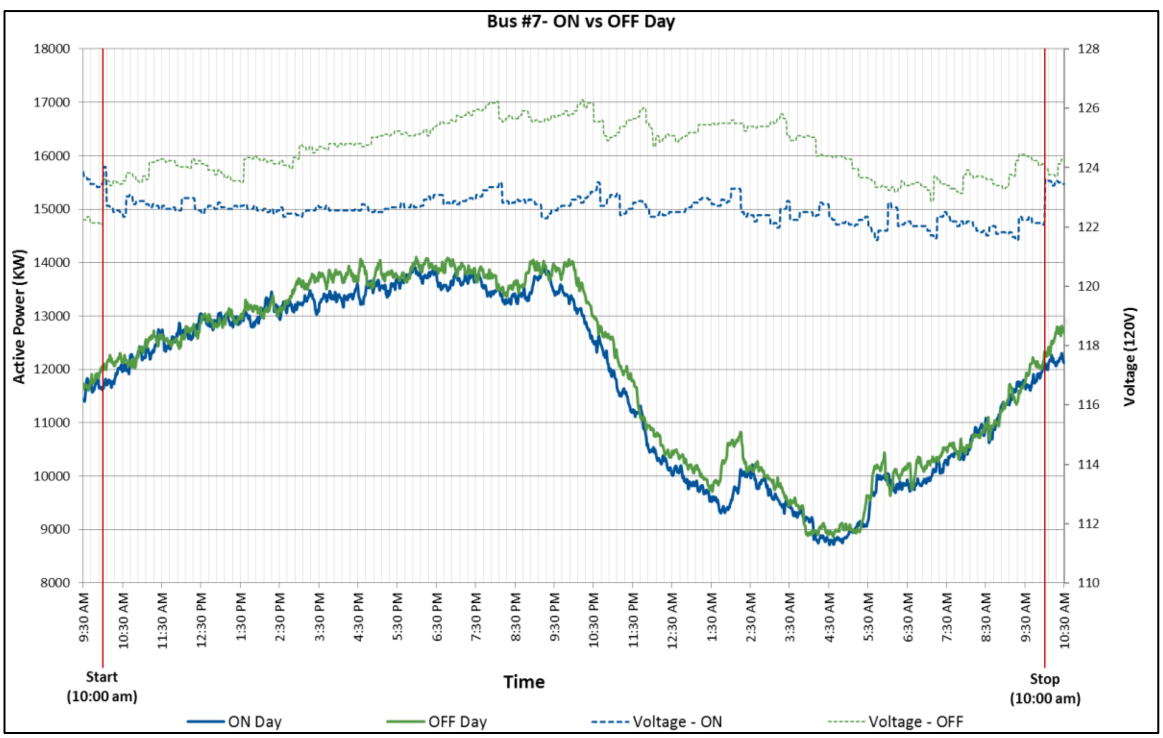
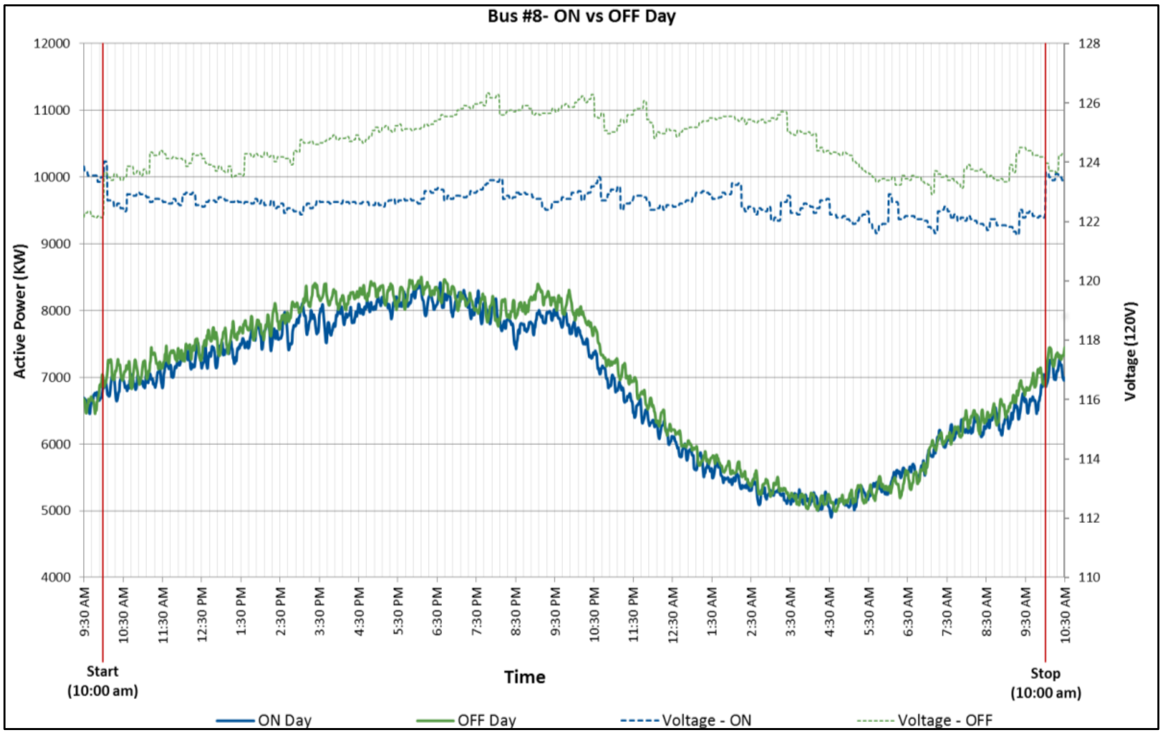


Figure 3-41: Bus #8 Active Power & Voltage Comparison (07/15 – 07/16)



3.4.1.1.2.3 Demand Reduction Achieved from DVC (Notch) Mode

The DVC testing mode, or the notch mode, was used to implement VVC in CVR mode for 2 hours, to demonstrate demand-response capabilities of VVC that could be utilized during peak load periods.

DVC testing was conducted every Friday throughout the testing period, to accommodate on/off testing days for the rest of the week. The initial approach taken for DVC testing was to compare notch days with off days, and to identify matches for notch-off days as had been done for on-off days. While thorough analysis was conducted (similar to analysis during on-off days) a substantial number of matches could not be established. Because notch days (Fridays) had a load profile consistently different from that of the other weekdays, no matches could be established. An alternate approach for analysis was devised, and will be explained in detail in this section.

The VVC application was able to successfully reduce the voltage for a notch day, much like the reduction achieved during an on day.

Table 3-38 shows the list for notch days and corresponding decreases in voltage achieved by VVC. The reduction in voltage ranged from 1.14% to 2.21%, with an overall reduction of 1.64%.

Table 3-38: Notch Voltage Reduction

Notch Day	Overall Voltage Reduction	Reduction at Start	Reduction before Stop
6/13/2014	1.22	0.55	1.89
7/18/2014	1.75	2.24	1.25
8/8/2014	1.22	1.10	1.35
8/15/2014	1.14	0.98	1.29
9/12/2014	1.86	2.63	1.09
9/26/2014	2.21	2.44	1.98
10/3/2014	1.41	1.20	1.62
10/17/2014	2.10	1.77	2.42
10/24/2014	1.82	1.61	2.03
Overall	**1.64%**	**1.62%**	**1.66%**

In the above table, the last two columns represent the voltage reduction measured at the start of the notch period, and voltage increase measured after the end of the notch period. Notch data was analyzed on a trend basis, comparing voltage data prior to and following the start of the notch period. A 5-minute buffer period after the start was used to let the tap changer and capacitor banks switch into positions directed by VVC for the first time during the notch. Initially, 10 minutes of data (both before and after the start) were used but it was observed that changes in load were drastic. Subsequently, 20 minutes of data before and after the start of the notch period, with a 5-minute gap after the start, was used. Similarly, voltage data at the end of the notch was also analyzed, including a 5-minute gap after the notch period ended, or VVC was stopped, to let the local tap changer control and cap bank controls take back control and change positions to normal.

For example, if a notch period started at 2:00 PM, then the voltage data from 1:40 PM to 2:00 PM was compared with the data from 2:05 PM to 2:25 PM. Similarly, if a notch period ended at 4:00 PM, then the voltage data from 3:40 PM to 4:00 PM was compared with the data from 4:05 PM to 4:25 PM.

Figure 3-42: 06/13/2014 Voltage (Notch Period)

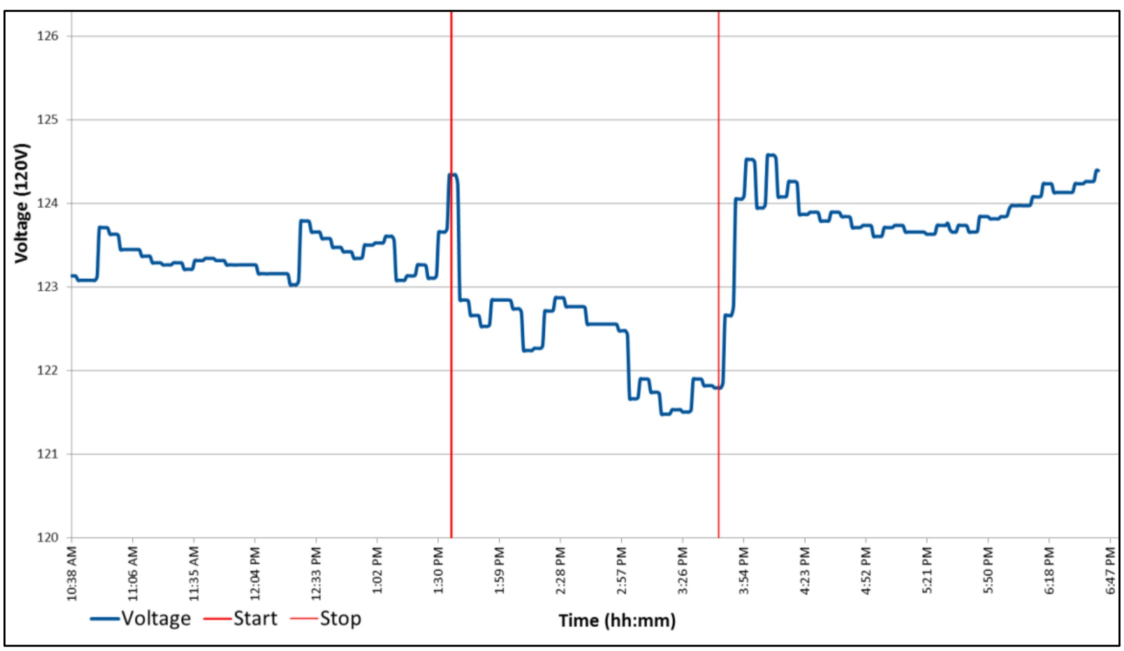
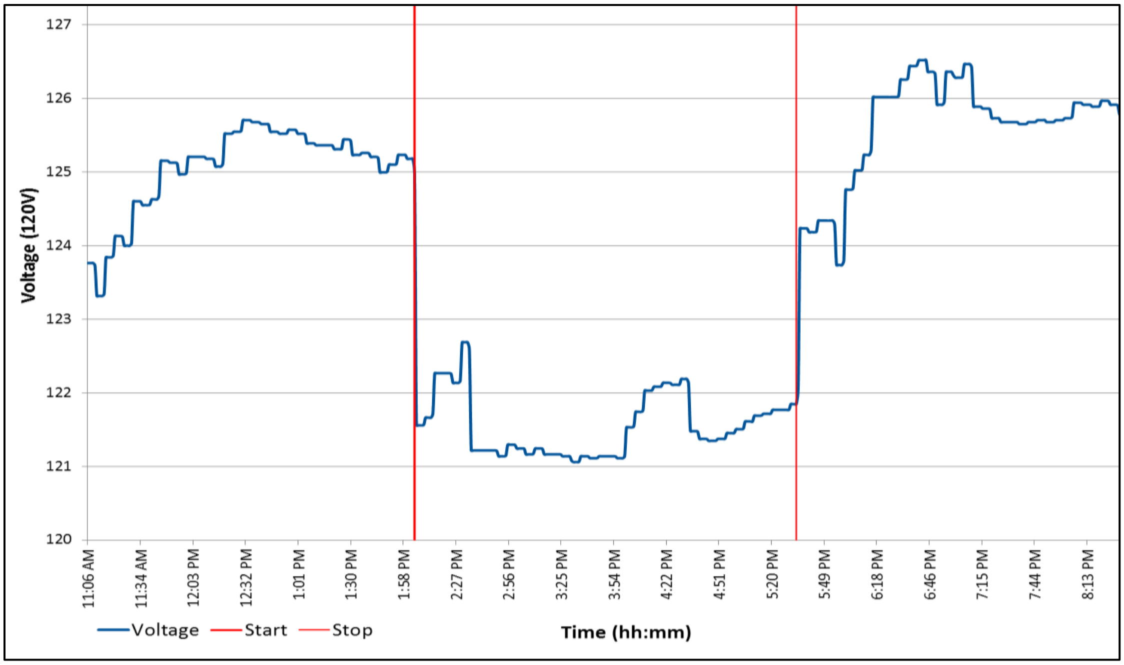


Figure 3-42 above displays the voltage plot for 06/13 — a notch day including data from 3 hours prior to and after the notch period. The drop in voltage (1.22%) as a result of VVC can be observed during the duration of the notch period. Figure 3-43 below displays the voltage reduction achieved for another notch day that had the most reduction in voltage (2.21%). The reduction as observed for the on days varies from day to day based on the loading and the VVC settings. Extreme high load days provide for lesser scope of reduction in voltage as the voltage drop on secondary circuitry is considerable and does not allow for further reduction in voltage.

Figure 3-43: 09/26/2014 Voltage (Notch Period)



The reduction in voltage also generated a corresponding reduction in active power. The day and time of the notch test period proved to be a slight challenge for the analysis, as the active power on a Friday tends to considerably increase during the notch timeframe throughout the testing period. An analysis method similar to voltage was used and the active power reduction achieved from DVC mode is shown in Table 3-39.

Table 3-39: Notch Reduction

Notch Day	Voltage Reduction	Active Power Reduction	Overall CVRf
6/13/2014	1.22	0.84	0.69
7/18/2014	1.75	1.65	0.94
8/8/2014	1.22	0.67	0.55
8/15/2014	1.14	0.38	0.34
9/12/2014	1.86	1.15	0.62
9/26/2014	2.21	1.07	0.48
10/3/2014	1.41	2.29	1.62
10/17/2014	2.10	0.40	0.19
10/24/2014	1.82	1.68	0.93
Average	**1.64%**	**1.13%**	**0.71**

Figure 3-44, Figure 3-45, and Figure 3-46 display the voltage and active power plots from 3 hours before the start of the notch period to 3 hours after the notch period ended. The reduction in voltage (dotted) can be observed during the notch period and the corresponding reduction in active power can also be observed on the entire transformer and on the individual bus.

Figure 3-44: 07/18/2014 Total Voltage and Active Power (Notch Period)

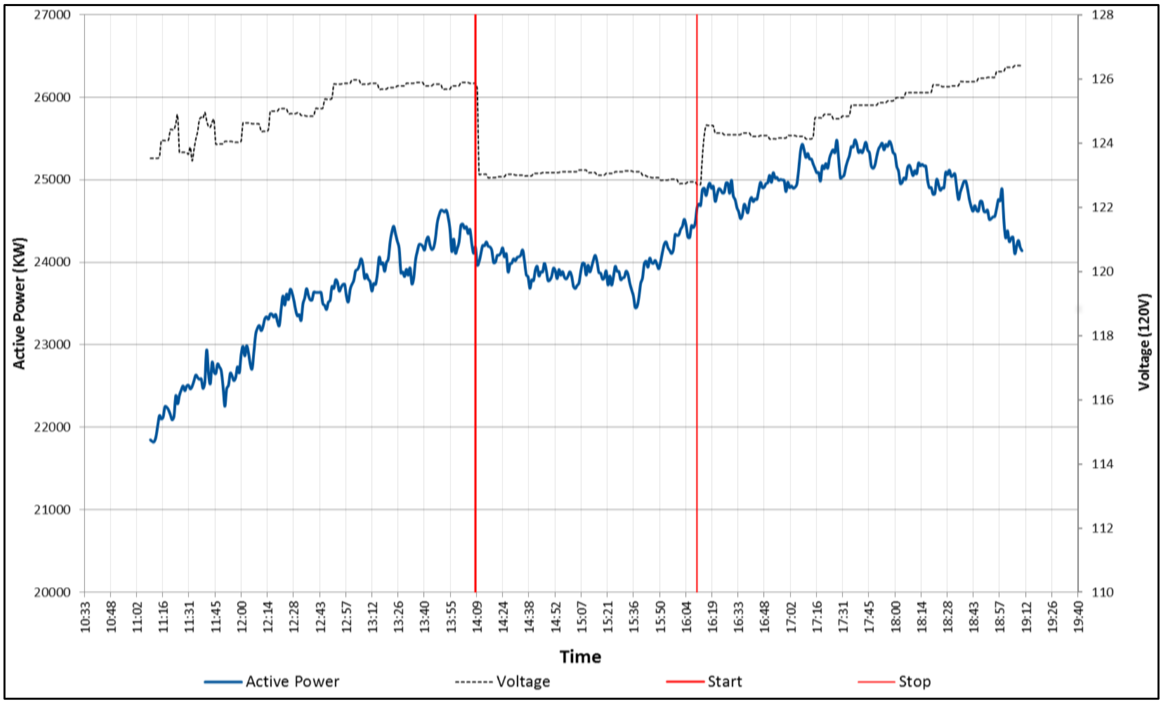


Figure 3-45: 07/18/2014 Bus #7 Voltage and Active Power (Notch Period)

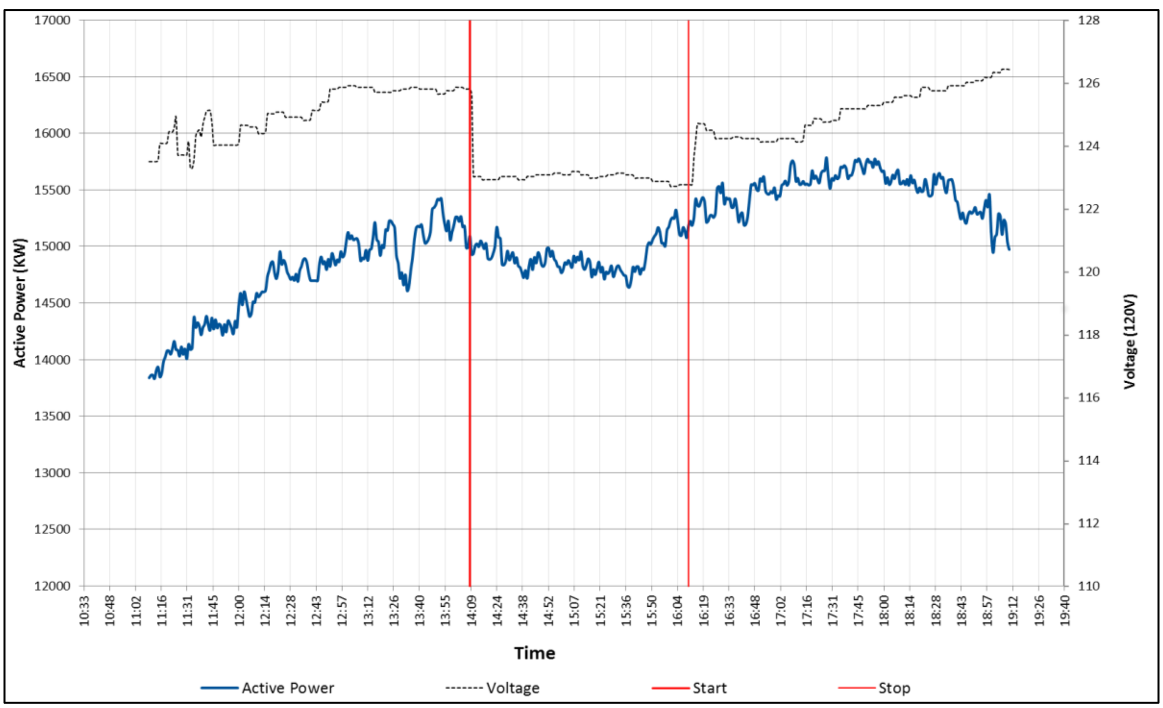
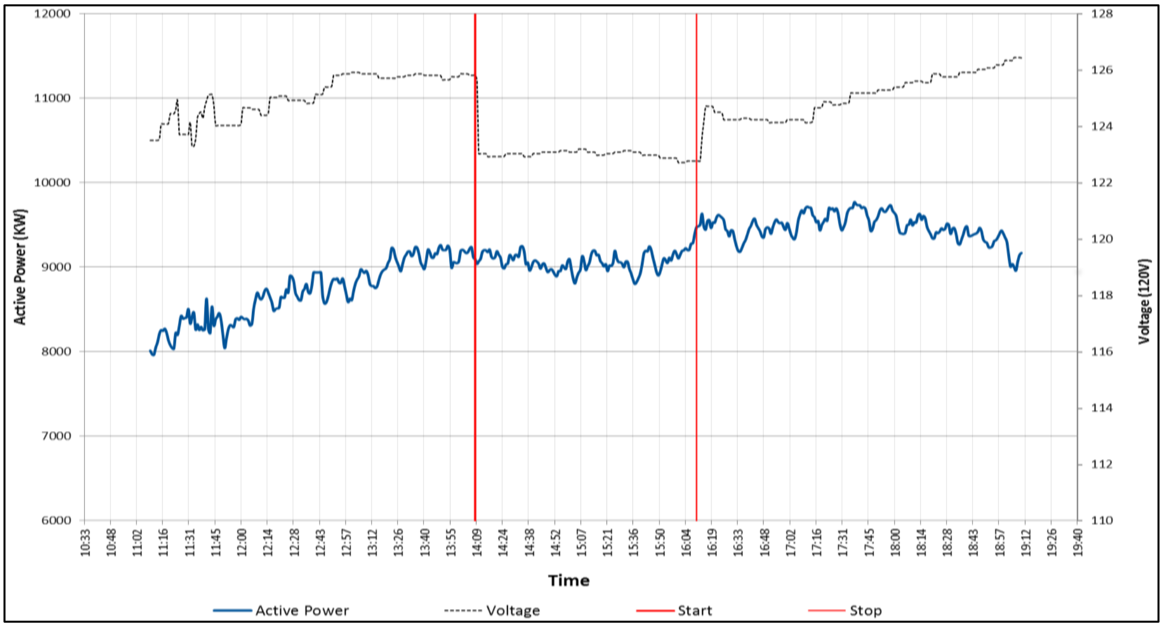


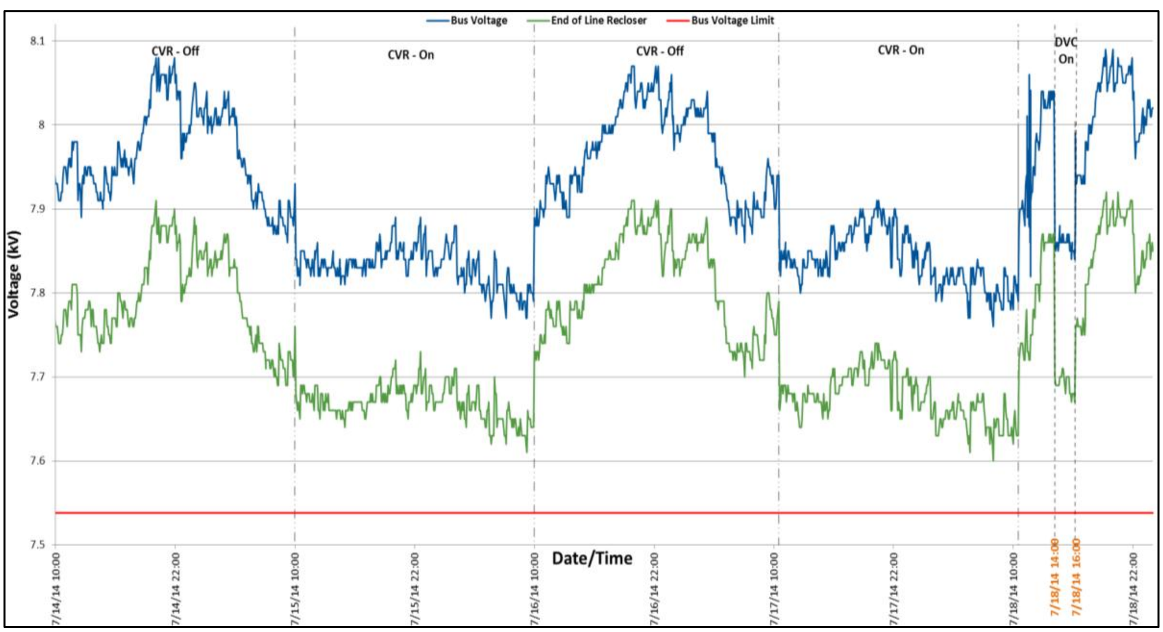
Figure 3-46: 07/18/2014 Bus #8 Voltage and Active Power (Notch Period)



3.4.1.1.2.4 Improved Voltage Stabilization under VVC Operation

The centralized, controlled VVC implementation stabilized voltage at the bus level and, as a consequence, all along the feeder up to the end of line recloser. As shown in far left portion of Figure 3-47, voltage during an off day without VVC day varied from 7.9 kV to 8.1 kV, whereas the voltage during an on day with VVC varied from 7.77 kV to 7.88 kV. The variation in voltage over the entire day was reduced as the VVC application controlled the cap banks and tap changer simultaneously on a real-time basis using the state estimator values that were updated every 15 minutes or on a major system change. On the off day, the voltage was regulated by local controllers at the cap banks and tap changer, which proved to be less efficient as the VVC. Voltage during the on day is remarkably flatter, something observed throughout the testing period.

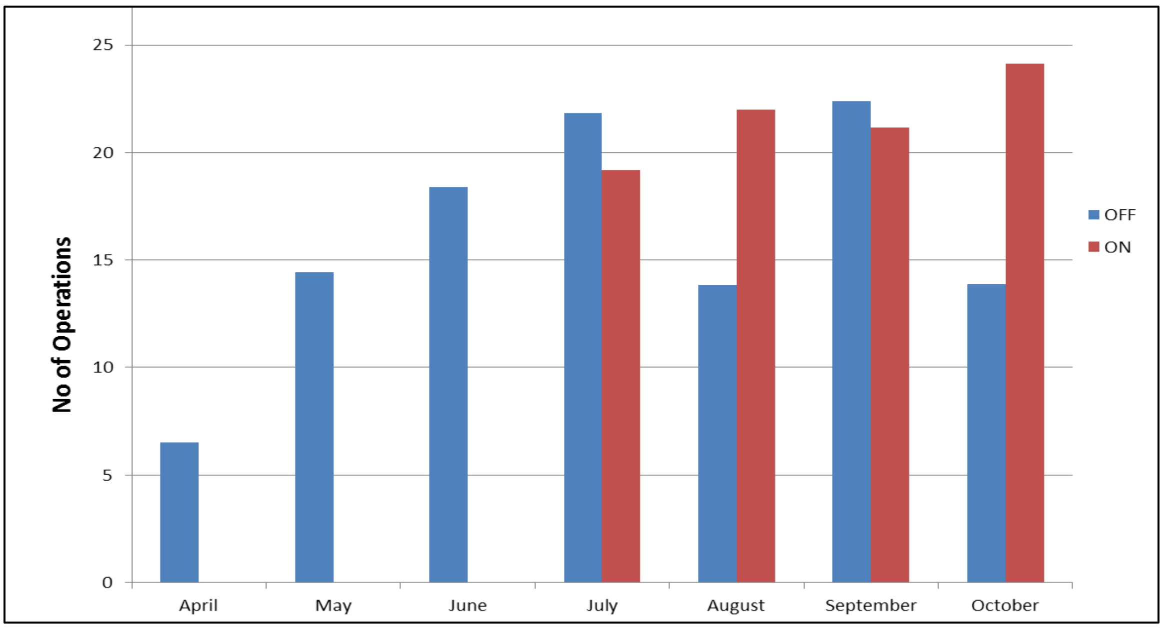
Figure 3-47: Bus Voltage and End of Line Recloser Voltage (Full VVC Week 07/14 – 07/18)



3.4.1.1.2.5 VVC Impact on Tap Changer Operations

The VVC application used the tap changer considerably and a major discussion point is the number of tap changes effected by VVC and if these were detrimental to the tap changer. In the KCP&L implementation, the number of tap operations on weekdays during the testing period and a few months before the testing period were analyzed. It was observed that there was an overall increase in tap operations during the VVC testing period but there was a marked increase as the testing period approached. This increase in number of tap operations could be attributed to a weather change, not the VVC program. During the testing period the average tap changes during off days (17.98) were less than during on days (21.62). The VVC program, if implemented continuously for an extended period, would reduce the number of tap changes because there would not be a need for tap operations to change from local control to VVC. Figure 3-48 shows the number of tap operations during the testing period.

Figure 3-48: Average Daily Tap Operations



3.4.1.1.2.6 Issues and Corrective Actions

The following issues and corrective actions were encountered during performance of the Integrated Volt/VAR Management operational demonstration and analysis.

Table 3-40: Issues and Corrective Actions

Issue	Corrective Action
• The vendor's VVC uses only calculated voltages for all calculations. All voltages are calculated from a source voltage at primary level of the substation transformer. The difference between measure and calculated values varied from 1% to 10%.	• The vendor changed the database so that the primary source voltage was calculated directly from a measured value on the secondary of the transformer. The difference between measure and calculated values dropped to 0.01%.
• Two secondary buses created a modeling issue. As a result, tap changer also did not use its field value and estimated its tap position creating voltage errors.	• The vendor rectified the issue by combining both secondary buses into a single secondary of the transformer.
• Cable capacitance generated a small increase in voltage at the load that was not reflected in the calculated values.	• Cable capacitance was slightly adjusted to correct error.
• Tap Changer locked out — VVC moved tap changer to its lowest position, where it locked out as a result of high voltage.	• Voltage on the secondary was observed to be consistently on the high side, and the high side tap was changed to decrease the voltage. VVC did not operate near the lowest tap thereafter.
• Recloser currents from the field did not correlate with calculated values.	• Reclosers were investigated and an incorrect relay setting (CT ratio) was identified and corrected on affected reclosers.

3.4.1.1.3 Findings

The results obtained in the execution and analyses of the Integrated Volt/VAR Management operational demonstration are summarized in the sections below.

3.4.1.1.3.1 Discussion

The KCP&L VVC program primarily aimed to demonstrate the ability of a centralized VVC application to achieve better volt/VAR control than traditional schemes based on local control. Implementation during all phases provided numerous reminders of the benefits of a centralized volt/VAR controller — be it modifying cap bank settings during the planning phase, identifying asset issues from VVC application exclusions, improving voltage control all along the implementation, or reducing active power determined during the analysis.

VVC, when run continuously for a period of 24 hours (CVR mode), was able to reduce voltage at the bus level by 2.05% on average during the operational period. This in turn produced a 1.63% reduction in energy (kWh) consumed at the substation level. Over the testing period it was observed that a small number of meters on each feeder prevented the voltage from being lowered further by VVC. Moving these meters to another feeder or taking additional actions to reduce the secondary voltage drop would have enabled to reduce overall voltage up to 3% or more. Additionally, only three out of the eight feeders on the transformer used for VVC were automated, thus providing lesser opportunity to control voltage on all the feeders and set aggressive voltage limits in the application.

AMI data utilized for the VVC analysis proved inconclusive, as the aggregations provided were not consistent throughout the testing period and could not be used. It can be safely deduced, though, that a reduction in consumption at the substation level would produce a similar drop in load at the customer level by 1.63%. AMI integration into the DMS would have provided VVC additional leeway in better estimating voltages all along the distribution system and further reducing voltage across the system. The VVC limits had to be estimated by the user after observing the AMI meter pings. AMI integration could have provided more efficient feedback and scope for additional reduction.

The VVC program in DVC/notch mode similarly was able to reduce the kWh consumption on a Friday by 1.13% by reducing the voltage by 1.64%. The reduction for notch mode was less than for CVR mode and can be attributed to the undertaking pf DVC testing for a shorter period of time and at a time close to peak loading of the feeder. When implemented during peak load, VVC generated less reduction as larger voltage drops at the secondary level prevented the application from reducing voltage further. Again, many of these large secondary drops were concentrated on a few meters.

Results are summarized in Table 3-41. The overall CVR factor for each mode suggests a reduction in alignment with industry standards. The results demonstrate the scope for additional reduction in active power of reduction in voltage can be achieved.

Table 3-41: VVC Overall Results

Test Mode	Active Power Reduction	Voltage Reduction	Overall CVRf
CVR Mode	1.63%	2.05%	0.889
DVC/Notch Mode	1.13%	1.64%	0.71

3.4.1.1.3.2 Expectations vs. Actuals

The following table provides a comparison of the Expected Results and the Actual Outcomes for the Integrated Volt/VAR Management operational demonstration.

Table 3-42: Expected Results vs. Actual Outcome

Expected Results	Actual Outcome
• For each objective function KCP&L expected to see an incremental improvement in circuit operational performance.	• Due to operational constraints only the Minimize Active Power objective was demonstrated for the entire period.
• A recommended objective function would be selected for sustained operation of the SmartGrid Demonstration Circuits.	• Minimize Active Power function was the most appropriate for the urban SmartGrid circuits studied, even if it was not deployed for CVR.
• Due to KCP&L's active capacitor deployment and automation program, a significant improvement may not be achievable.	• While and economic benefit could not be determined, any of the VVC objective functions provided a more stable voltage profile compared to that of the individual, locally controlled capacitor banks.
• VVC, when implemented in CVR mode, would reduce the overall load on the system by 1-3%.	• VVC, when implemented in CVR mode, actually reduced the overall load by 1.63%, but with a CVRf of 0.89.
• VVC, when implemented in DVC mode, would reduce peak demand by 2%, consistent with the existing KCP&L DVC program.	• VVC, when implemented in DVC mode, reduced the hourly load by 1.13%.

3.4.1.1.3.3 Computational Tool Factors

The following table lists the values derived from the Integrated Volt/VAR Management operational demonstration that will be used as inputs to the SmartGrid Computational Tool.

Table 3-43: Computational Tool Values

Name	Description	Value
Distribution Feeder Load (MVA)	Average apparent power readings for all feeders impacted by the project	n/a
Distribution Losses (%)	Average losses for the portion of the distribution system impacted by the project expressed in a percentage of load	n/a
Distribution Capacity Deferred (kVA)	The size of the distribution investment deferred as a result of VVC.	559 kVA
Capital Carrying Charge of Distribution Upgrade	The total capital cost of distribution system investments that can be deferred as a direct result of the project.	$178,471
Distribution Investment Time Deferred	The time in years that the distribution investment will be deferred.	5 yr.
Reduced Total Customer Peak Demand (MW)	The total customer peak demand for customers within the project scope.	0.559 MW
Reduced Annual Generation (MWh)	The amount of generation dispatch avoided.	3,376 MWh
Reduced Annual Generation Cost ($)	Reduced total cost of producing or procuring electricity to serve load.	$ 112,126
Reduced Total Residential Electricity Cost (Consumer) ($)	The reduction total amount of money spent on electricity by residential customers annually.	$172,072
Reduced Total Commercial Electricity Cost (Consumer) ($)	The reduction total amount of money spent on electricity by residential customers annually.	$101,799
Reduced CO2 Emissions (tons)	CO2 emissions from central generating sources	3037.7 tons
Reduced SOx Emissions (tons)	Sox emissions from central generating sources	4.037 tons
Reduced NOx Emissions (tons)	NOx emissions from central generating sources	3.239 tons
Reduced PM2.5 Emissions (tons)	PM2.5 emissions from central generating sources	.03451 tons

- Reduced Annual Generation (MWh) – Based on the 2014 impact metric data, this value is calculated as follows:

([Total Residential Customers (#) x Average Annual Residential Customer Electric Usage (kWh)] + [Total Commercial Customers (#) x Average Annual Commercial Customer Electric Usage (kWh)] + [Total Ind. Customers (#) x Average Annual Ind. Customer Electric Usage (kWh)]) x VVC Active Power Reduction Factor (%) ÷ 1000 kWh/MW =

([12,204 x 7,982 kWh] + [1,223 x 89,715 kWh] + [0 x 0 kWh]) x 1.63 % ÷ 1,000 kWh/MWh = 3,376.28 MWh

- Reduced Annual Generation Cost ($) – Based on the 2014 impact metric data and the hourly energy costs in the SPP Day Ahead Energy Market, this value is calculated as follows:

  Reduced Annual Generation (MWh) x Avg. Annual Generation Cost ($/MWh) =
  3,376.28 MWh x $33.21/MWh = $112,126

- Reduced Total Customer Peak Demand (MW) – Based on the 2014 impact metric data, this value is calculated as follows:

  Peak Load-Total Amount (MW) x DVC Active Power Reduction Factor (%) =
  49.475 MW x 1.13% = 0.559 MW

- Capital Carrying Charge of Distribution Upgrades ($) – Using an incremental distribution deferral method based on reduced customer peak demand this value is calculated as follows:

  Reduced Total Cust. Peak Demand (MW) x 1,000 (kVA/MVA) x
  Typical Cost of Dist. Capacity ($/kVA-yr) x Life Cycle Value Multiplier =
  0.559 MW x 1,000 kW/MW x $23.94/kW x 13.3362 = $178,471

- Distribution Investment Time Deferred (Yr.) – The distribution investment deferral is assumed to be 5 years due to the fact that the project team is using an incremental calculation and aggregating all incremental distribution deferral components into a single SGCT value.

- Reduced Total Residential Electricity Cost (Consumer) Cost ($) – Based on the 2014 impact metric data, this value is calculated as follows:

  Total Residential Customers (#) x Average Annual Residential Customer Electric Usage (kWh) x
  Average Energy Rate-Residential ($/kWh x VVC Active Power Reduction Factor (%) =
  12,204 x 7,982 kWh x $0.10837/kWh x 1.63% = $172,072

- Reduced Total Commercial Electricity Cost (Consumer) Cost ($) – Based on the 2014 impact metric data, this value is calculated as follows:

  Total Commercial Customers (#) x Average Annual Commercial Customer Electric Usage (kWh) x
  Average Energy Rate-Commercial ($/kWh x VVC Active Power Reduction Factor (%) =
  1,223 x 89,715 kWh x $0.05692/kWh x 1.63% = $101,799

- Reduced CO_2, SOx, NOx, and PM-2.5 Emissions (tons) – Based on the factors derived from the 2010 emission values contained in the 2014 update of the DOE Emissions & Generation Resource Integrated data base for the SPP North subregion, these values are calculated as follows:

  CO2 Emissions – Reduced Annual Generation Production (MWh) x (lbs CO_2/MWh) ÷ (lbs/ton)
  3,376.28 MWh x 1,799.45 lbs CO2/MWh ÷ 2,000 lbs/ton = 3,037.7 tons CO2

  SOx Emissions – Reduced Annual Generation Production (MWh) x (lbs SOx/MWh) ÷ (lbs/ton)
  3,376.28 MWh x 2.5511 lbs SO2/MWh ÷ 2,000 lbs/ton = 4.307 tons SOx

  NOx Emissions – Reduced Annual Generation Production (MWh) x (tons NOx/MWh)
  3,376.28 MWh x 1.9186 lbs NOx/MWh ÷ 2,000 lbs/ton = 3.239 tons NOx

  $PM_{2.5}$ Emissions – Reduced Annual Generation Production (MWh) x (tons PM2.5/MWh)
  3,376.28 MWh x 0.00001022 tons PM2.5/MWh = 0.03451 tons PM2.5

  Where: ton $PM_{2.5}$/MWh =
  12.27 MMBTU/MWh ÷ 19.21 MMBTU/ton-coal x 0.000016 ton $PM_{2.5}$/ton coal = 0.00001022

3.4.1.1.4 Lessons Learned

Throughout the conduct of operational testing and analysis of the Integrated Volt/VAR Management function, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- Eliminating Low Voltage areas before implementing VVC — Over the course of the KCP&L implementation it was observed that a specific load or secondary transformer had voltage 1-3 V lower than the rest of the load. This single transformer of load limited further reduction of voltage by the VVC application on that feeder. Prior analysis of AMI data and the rectification of these low-voltage loads by replacing conductors or shifting them to another transformer or feeder, etc., could have provided scope for additional reduction of voltage on most feeders and could have increased the efficiency of VVC in CVR mode.
- DMS Data Model — Advanced DMS applications such as VVC require a high level of data accuracy as they rely on calculated and estimated data that is highly accurate, whereas applications such as FISR (Fault Isolation and Service Restoration) rely majorly on switch data and a somewhat accurate state estimator. The Siemens State Estimation application proved to be a great resource in comparing calculated and measured values based upon which the data model (recloser configurations, tap changer configurations, cable impedances, etc.) adjusted to reduce the difference between calculated and measured values. This meant high accuracy of the State Estimator results, which resulted in optimal VVC results. Thorough data model analysis and rectification of major issues prior to initial implementation shall help improve results and save time.
- AMI Integration — Integration of AMI data into the DMS increases the monitoring capabilities of the DMS, thereby maximizing accuracy of state estimation application and efficiency of the VVC application on the DMS. KCP&L's DMS was not integrated with the AMI system, introducing a significant amount of complexity and numerous manual processes into planning and implementation. Much of the users' time could have been saved with AMI integration. Such integration also would have provided more scope for reducing the voltage for CVR, identifying problematic areas in advance, broader voltage control across the system and an even more efficient Volt/VAR program.
- Measured Value Utilization — The KCP&L State Estimator and VVC use the source voltage measured values to calculate voltages across the remainder of the system from that measured value. Any error in the source voltage measurements, or any inconsistencies in the data model, result in the voltage calculations that will not be realized by the state estimator, making the system and the application unreliable. Distribution state estimation algorithms and, more importantly, Volt/VAR applications must use measured voltages as part of their calculation or at the least to detect voltage violations.
- AMI Data Aggregation – The initial objective of the VVC program was to use to the AMI data to calculate the losses on the distribution system and to determine the savings of the customer. The feeder assignment for each AMI meter was not consistent as meters are swapped regularly and the data was not updated in the data aggregator on a real time basis. The aggregated data was inconsistent with the field values as the meters on a specific feeder were all not accounted to that feeder in the aggregation system. The team used various analysis methods to extract the correct meter list and data for each feeder and aggregate it but were unsuccessful in overcoming the quality of the data and abandoned VVC analysis with AMI data. Extreme care must be taken in handling AMI data and manipulating it in the future for analysis with options to aggregate not only at the substation level but at the transformer and feeder levels.

3.4.2 Real-Time Load Transfer

Real-time load transfer is achieved through real-time feeder reconfiguration and optimization to relieve load on equipment, improve asset utilization, improve distribution system efficiency, and enhance system performance.

3.4.2.1 Feeder Load Transfer

Feeder Load Transfer (FLT) is a demonstration of one aspect of the Real-Time Load Transfer function. Feeder Load Transfer involves remodeling distribution circuits, using remote and manual switches, to reduce losses in the distribution system. Manual switches could be used on a long-term/seasonal basis, while the application could use remote switches to optimize the system on a more regular basis.

3.4.2.1.1 Overview

The following sections provide an overview of the operational, demonstration, testing, and evaluation methodology used for the Feeder Load Transfer operational demonstration.

3.4.2.1.1.1 Description

KCP&L circuit configurations are currently established based on engineering planning studies and focused on optimizing the distribution system under peak load conditions. The FLT application performed a real-time analysis to determine the optimal radial distribution network configuration to serve the current load. FLT analysis minimizes electrical losses while maintaining current and voltage levels within technical limits.

Automated switches with two-way communications were deployed on five of the 12 SmartGrid distribution circuits, to allow remote circuit reconfiguration. Using FLT switching plans were developed to implement the recommend configuration, which may be implemented automatically or manually by the distribution grid operator.

3.4.2.1.1.2 Expected Results

This operational demonstration was expected to yield the following:

- FLT analysis makes changes to the “Normal” circuit configurations that will be more efficient and reduce distribution system losses.
- FLT may identify real-time, daily, or seasonal reconfigurations that will be more efficient and reduce distribution system losses.

3.4.2.1.1.3 Benefit Analysis Method/Factors

The DOE SGCT was used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits were quantified.

- Reduced Electricity Losses
- Deferred Distribution Capacity Investments

Benefits were calculated using SGCT formulas. The following factors were measured, projected or calculated during the application operation and/or demonstration.

Reduced Electricity Losses

- Distribution Feeder Load (MW)
- Distribution Losses (%) (base & projected)

Deferred Distribution Capacity Investments

- Capital Carrying Charge of Distribution Upgrade ($/yr)
- Distribution Investment Time Deferred (yrs)

3.4.2.1.1.4 Testing Methodology

The following points provide an overview of how the operational demonstration and testing for this application was accomplished:

- Testing for the FLT application occurred periodically throughout the operational period during different seasons, times of day, and system loading levels.
- FLT testing was conducted independently of VVC and other application testing that impacts distribution grid characteristics.
- With grid reconfiguration, measurement of distribution grid losses is extremely difficult. Therefore, the improved grid efficiency was determined based on DNA calculations. Grid loss impact was measured in two ways: 1) The FLT application provides a calculation of loss savings that is expected based on the proposed reconfiguration; 2) the DNA State Estimation/Load Flow loss calculations were recorded before and after the reconfiguration was implemented.
- During each test period, the DMS FLT operational parameters were adjusted to maximize the potential benefits achievable.
- The AMI system was used to collect circuit load profile data for each circuit. AMI circuit data not involved in the test was used as control for the analysis.
- DMS collected voltage profile data for all SCADA-enabled equipment.

3.4.2.1.1.5 Analytical Methodology

The following points provide an overview of the analytical methods that were used to evaluate the impact and benefits of this application:

- AMI interval load data for all circuit load meters within the Project area was aggregated to develop an hourly load profile of the combined circuit load.
- For each operational test, the before and after calculated grid losses from the DNA Results were compared to determine the reduction in technical (I2R) losses.
- Total annual loss savings were projected by calculated by extrapolating the individual test results using the annual hourly load profile for the project area.
- Additionally, hourly pricing, hourly system load, hourly substation load (from SCADA), and hourly AMI feeder load from October 2012 through October 2014 were obtained to determine potential savings for duration of the entire project.

3.4.2.1.2 Plan Execution and Analysis

The following sections provide details regarding the functional tests performed, data collected, and analysis performed for the Feeder Load Transfer operational demonstration.

3.4.2.1.2.1 Demonstration Overview

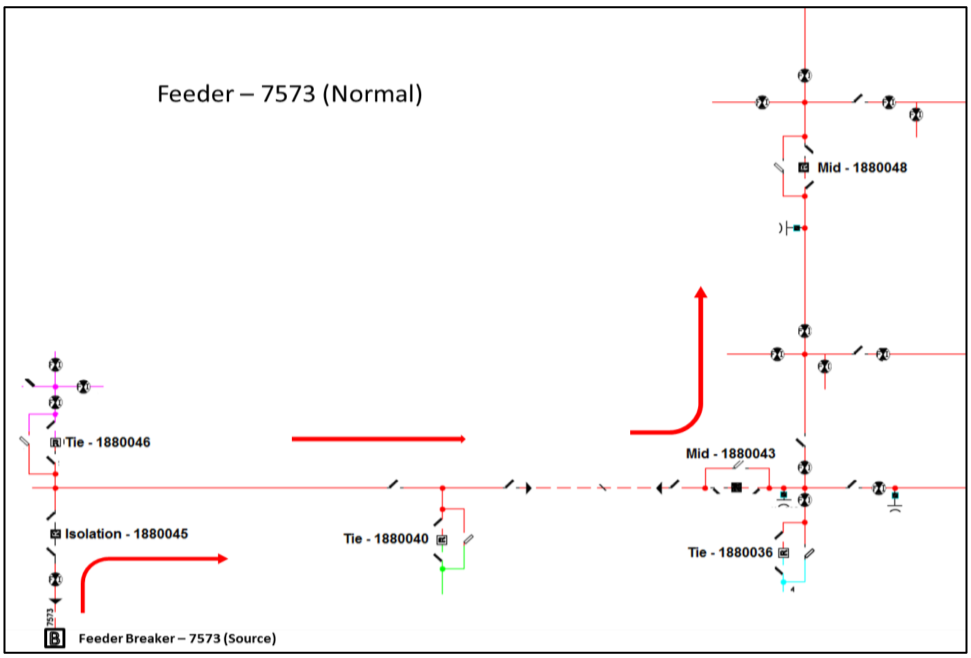
The FLT application performed a real-time analysis to determine the optimal radial distribution network configuration to serve the current load. The application identifies normally open switches in the area and all related normally closed switches that can be switched along with the open switch to reconfigure the radial configuration. The application runs state estimation for each configuration and generates a solution if any of the reconfigurations meet the objective requirements.

The FLT operational test was focused on the five highly automated feeders and then expanded to the 12 SmartGrid distribution circuits. The FLT application is optimized when utilizing remote automated switches. Here is a brief description of the remote automated switches present in the SmartGrid area; KCP&L's SmartGrid circuits typically have three types of reclosers:

- Isolation Reclosers – These are placed prior to the first load, typically to isolate the underground feeder cable portion of the feeder from the overhead. They provide the ability to isolate and restore the entire feeder in case of a cable fault.
- Tie Reclosers – Normally open, these reclosers are located at the edge of the radial configuration of the feeder with a connection to another feeder to serve as an alternate feed if needed.
- Mid-Circuit Reclosers – These are placed on the backbone of the feeder with the intent of splitting the feeder into smaller sections that are similar in size in terms of load or customer count. Each section split by a mid-circuit is typically 50% or 33% of the feeder.

The largest SmartGrid feeder contained six reclosers – one (1) isolation, three (3) tie and two (2) mid-circuit reclosers, as shown below. The smallest section of the feeder contained 28% of the load of the entire feeder.

Figure 3-49: Largest SG Feeder with Reclosers (7573 – Red)



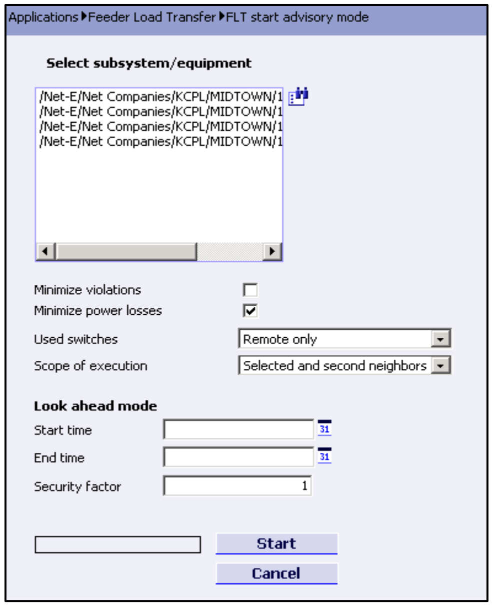
The total number of reclosers in the SmartGrid area is as follows:

- Six (6) Tie Reclosers
- Five (5) Isolation Reclosers
- Eight (8) Mid-Circuit Reclosers

The feeders were fed by a two different transformers and did not have any interconnection or ties with adjacent substations. This drastically limited the number of ties and, hence, the number of alternate configurations that could be achieved using the automated switches. The mid-circuit sections encompassed at least 30% of the load and in some cases more than 50% of the load. Due to the small area of implementation and the small number of switches, FLT was run in real time and study mode (with operator modifications) to better realize the benefits of FLT.

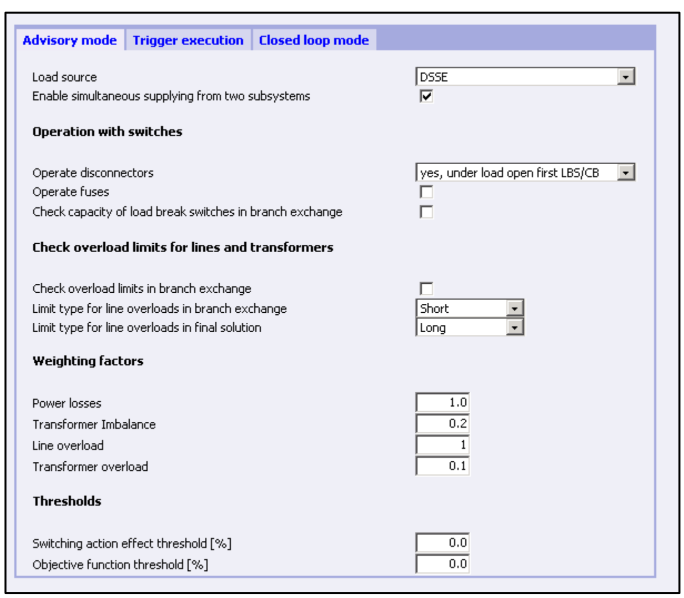
The FLT application has two major objectives: Minimize Violations and Minimize Power Losses. The screenshot below shows the start page for FLT. The operator can choose the area of implementation, check the required objective (or both), select the type of switches to be used (Remote or All), and the scope of execution. The area of implementation and scope of execution were set to all transformers and all feeders in the SmartGrid area for all executions, to maximize the chance for a solution. The used switches and the objective selections were changed as needed for each execution. This is indicated in the screenshot shown below (Figure 3-50).

Figure 3-50: FLT Start Window



In addition to the above functionalities, there are other parameters that can be configured to further tune the result to the needs of the operator. The parameters were configured as shown in Figure 3-51, and the same were kept for the entire duration of the operational tests in different modes.

Figure 3-51: FLT Parameter Window



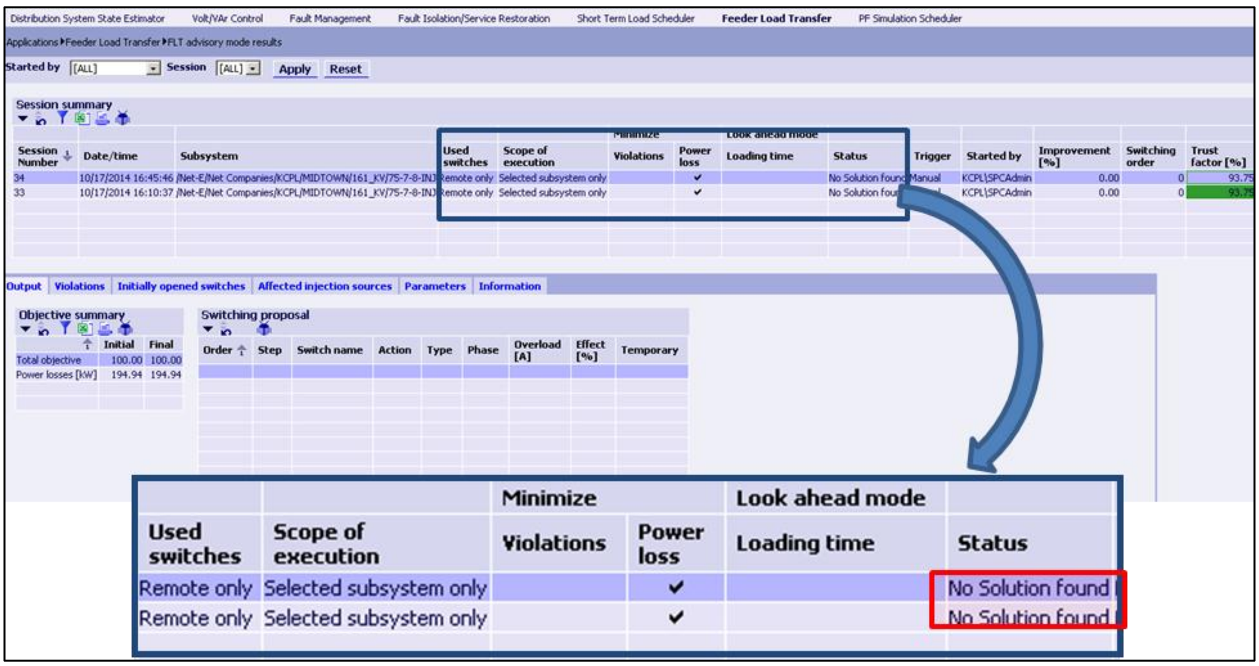
FLT results for each of the minimize power losses and minimize violations objectives, using remote only switches and all switches if required, will be verified and analyzed in the following sections. The application was initially run on the real-time system and also in study mode to further analyze the results of the application.

3.4.2.1.2.2 Real-Time Execution in Loss Reduction Mode

The FLT application was run with the minimize losses objective during the operational test on the real-time system. Reviewed in this section are results from FLT in loss-minimization mode in the real-time system in different modes. The objective was to ensure that the smart grid feeders were in optimal radial configuration in terms of losses all along the operational test period. The application was first run considering only remote-automated switches and then run considering all switches.

Automated Switches Only – The application was initially run using only the automated switches on the SmartGrid feeders. As mentioned before there were five (5) highly automated feeders in the KCP&L SmartGrid area. The following screenshot, Figure 3-52, displays the results.

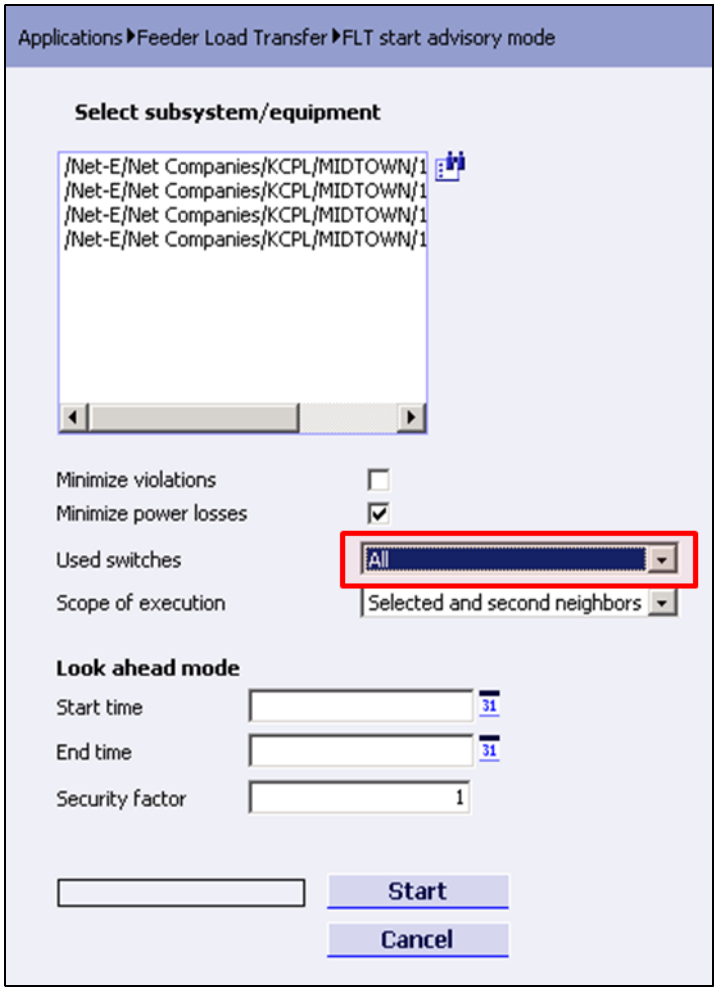
Figure 3-52: Result – Minimize Losses with Automated Switches



The application could not find an alternate configuration to reduce losses all along the operational test period, as the system is already optimized for low losses. The scope of the application in the KCP&L demonstration is limited to five (5) feeders, with only four (4) automated (remote) tie switches available that can be alternated with another closed switch. This greatly reduces the alternatives to that of the normal configuration. Any switching suggestion using only automated switches affects at least 30% of the load of the feeder and in most cases more than 50% of the load. A drastic increase/decrease in load on a specific feeder could create a situation that would necessitate a switching result from FLT. Seasonal changes have an impact across the system and the load on the feeders was not sufficiently diverse for seasonal changes to have any drastic impact on a specific feeder and not the rest of the system. This configuration did not change much over the operational period and FLT did not generate a result using remote switches all along the operational period for the normal configuration.

All Switches (Automated and Manual) – To further analyze the application and verify its results in real-time mode, the application was executed using all switches (as shown in Figure 3-53). The application could now provide switching recommendations by considering automated and manual switches, with the area of execution encompassing the seven (7) semi-automated smart grid feeders in addition to the five (5) highly automated feeders.

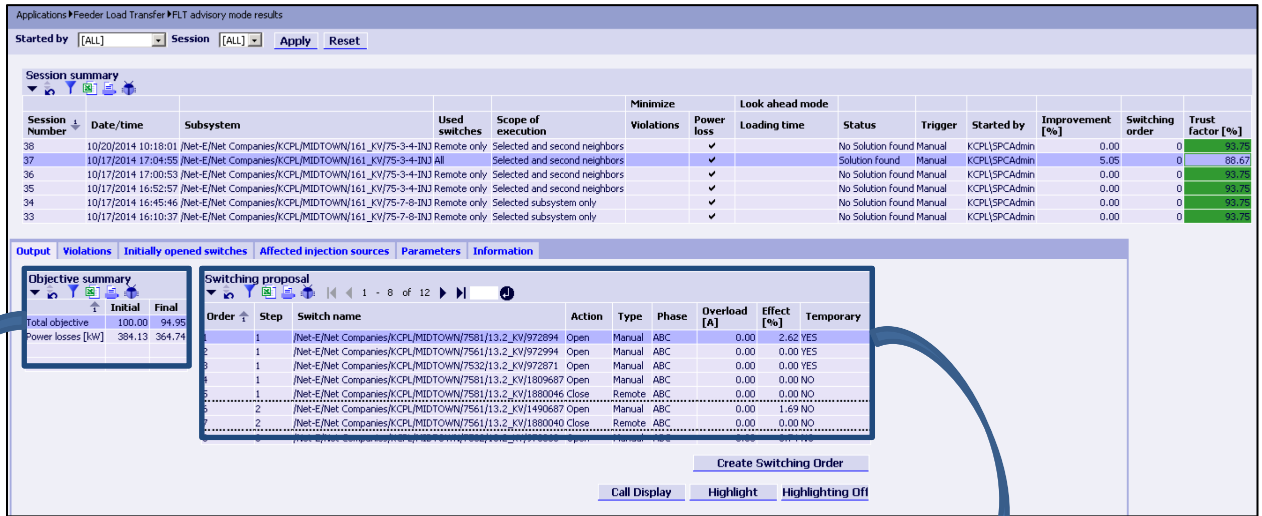
Figure 3-53: FLT Start Window



The number of manual switches on the smart grid feeders was far greater than automated switches, thus offering a plethora of options for the application to reconfigure the system. In this case the application had 43 tie switches available for switching, compared to the six (6) from the previous case. The additional switches gave the application the flexibility to make small changes to the configuration and fine tune it for maximum objective impact. Previously, a switching would have caused 30% of the load to be moved into another feeder, whereas a switching now could move only 5% of the load of the feeder. It should be noted all these switching steps need to be executed by a field crew and would involve temporary customer outages based on the parameters set for FLT.

The Results with all switches (Remote and Manual) are shown in Figure 3-54.

Figure 3-54: Result – Minimize Losses with Automated and Manual Switches #1



Switching proposal

1 - 8 of 12

Order	Step	Switch name	Action	Type	Phase	Overload [A]	Effect [%]	Temporary
1	1	/Net-E/Net Companies/KCPL/MIDTOWN/7581/13.2_KV/972894	Open	Manual	ABC	0.00	2.62	YES
2	1	/Net-E/Net Companies/KCPL/MIDTOWN/7561/13.2_KV/972994	Open	Manual	ABC	0.00	0.00	YES
3	1	/Net-E/Net Companies/KCPL/MIDTOWN/7532/13.2_KV/972871	Open	Manual	ABC	0.00	0.00	YES
4	1	/Net-E/Net Companies/KCPL/MIDTOWN/7581/13.2_KV/1809687	Open	Manual	ABC	0.00	0.00	NO
5	1	/Net-E/Net Companies/KCPL/MIDTOWN/7581/13.2_KV/1880046	Close	Remote	ABC	0.00	0.00	NO
6	2	/Net-E/Net Companies/KCPL/MIDTOWN/7561/13.2_KV/1490687	Open	Manual	ABC	0.00	1.69	NO
7	2	/Net-E/Net Companies/KCPL/MIDTOWN/7561/13.2_KV/1880040	Close	Remote	ABC	0.00	0.00	NO
8	3	/Net-E/Net Companies/KCPL/MIDTOWN/7532/13.2_KV/978868	Open	Manual	ABC	0.00	0.74	NO

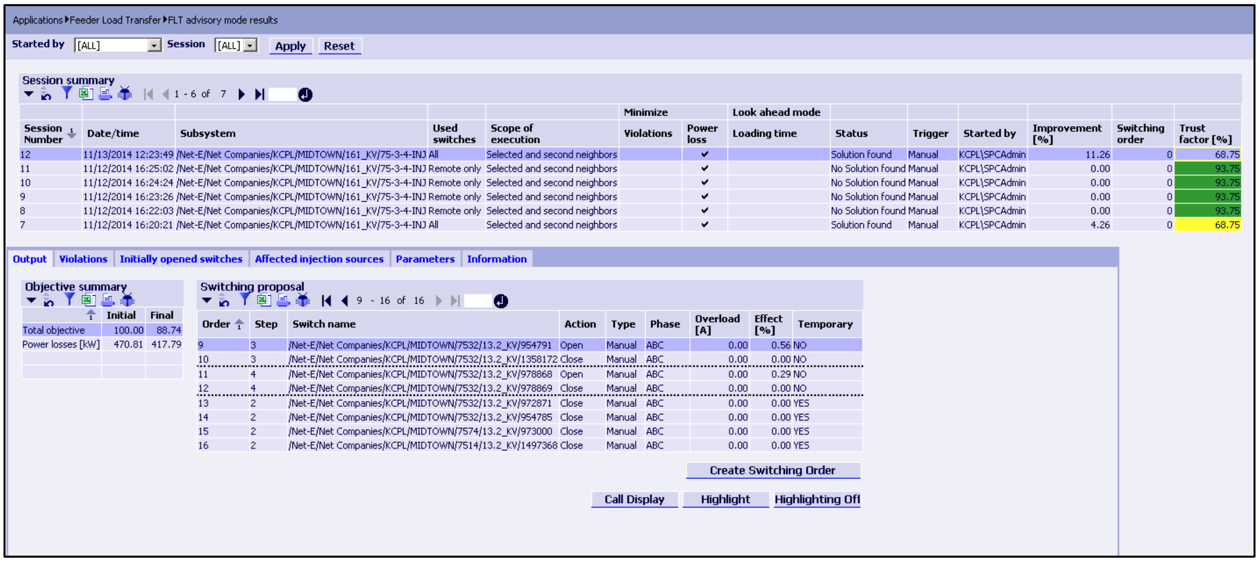
The application in this case generates a solution to reduce the power losses in the system. The above result is one of several recorded over the operational test period. The solution has 12 switching steps involving a combination of manual and automated switching. The objective summary from the result estimates that the losses can be reduced by 5.05% at the time of running the application.

Objective summary

	Initial	Final
Total objective	100.00	94.95
Power losses [kW]	384.13	364.74

The screenshots below (Figure 3-55) display another solution taken during the operational test period.

Figure 3-55: Result – Minimize Losses with Automated and Manual Switches #2



Switching proposal (1 - 8 of 16)

Order	Step	Switch name	Action	Type	Phase	Overload [A]	Effect [%]	Temporary
1	1	/Net-E/Net Companies/KCPL/MIDTOWN/7541/13.2_KV/972745	Close	Manual	ABC	0.00	9.71	NO
2	1	/Net-E/Net Companies/KCPL/MIDTOWN/7541/13.2_KV/972746	Open	Manual	ABC	0.00	0.00	NO
3	2	/Net-E/Net Companies/KCPL/MIDTOWN/7514/13.2_KV/1497368	Open	Manual	ABC	0.00	0.70	YES
4	2	/Net-E/Net Companies/KCPL/MIDTOWN/7574/13.2_KV/973000	Open	Manual	ABC	0.00	0.00	YES
5	2	/Net-E/Net Companies/KCPL/MIDTOWN/7532/13.2_KV/954785	Open	Manual	ABC	0.00	0.00	YES
6	2	/Net-E/Net Companies/KCPL/MIDTOWN/7532/13.2_KV/972871	Open	Manual	ABC	0.00	0.00	YES
7	2	/Net-E/Net Companies/KCPL/MIDTOWN/7514/13.2_KV/1077463	Open	Manual	ABC	0.00	0.00	NO
8	2	/Net-E/Net Companies/KCPL/MIDTOWN/7574/13.2_KV/979038	Close	Manual	ABC	0.00	0.00	NO

Switching proposal (9 - 16 of 16)

Order	Step	Switch name	Action	Type	Phase	Overload [A]	Effect [%]	Temporary
9	3	/Net-E/Net Companies/KCPL/MIDTOWN/7532/13.2_KV/954791	Open	Manual	ABC	0.00	0.56	NO
10	3	/Net-E/Net Companies/KCPL/MIDTOWN/7532/13.2_KV/1358172	Close	Manual	ABC	0.00	0.00	NO
11	4	/Net-E/Net Companies/KCPL/MIDTOWN/7532/13.2_KV/978868	Open	Manual	ABC	0.00	0.29	NO
12	4	/Net-E/Net Companies/KCPL/MIDTOWN/7532/13.2_KV/978869	Close	Manual	ABC	0.00	0.00	NO
13	2	/Net-E/Net Companies/KCPL/MIDTOWN/7532/13.2_KV/972871	Close	Manual	ABC	0.00	0.00	YES
14	2	/Net-E/Net Companies/KCPL/MIDTOWN/7532/13.2_KV/954785	Close	Manual	ABC	0.00	0.00	YES
15	2	/Net-E/Net Companies/KCPL/MIDTOWN/7574/13.2_KV/973000	Close	Manual	ABC	0.00	0.00	YES
16	2	/Net-E/Net Companies/KCPL/MIDTOWN/7514/13.2_KV/1497368	Close	Manual	ABC	0.00	0.00	YES

The application results using all switches were observed over a week and it was observed that the results varied drastically during that time. Each of the results contained a combination of manual and remote operations, with the manual steps varying from 10 to 40. Among observations drawn from the results:

- The solutions presented were transient in nature (changing daily or weekly) and would require multiple daily or weekly switching operations to keep the system continually optimized.
- The objective benefit from most of the solutions was not high enough to warrant sending out a field crew and to execute the switching order.

- A small subset of the switching proposal in most cases could generate most of the objective benefit of a solution. In the above solution the overall objective benefit is 11.26%, of which 9.71% is delivered by the first two (2) switching steps out of a total of 16.

The combination of the above factors led the team to conclude that the solution using manual switches was not feasible in the KCP&L SmartGrid system, although the application was capable of identifying switching steps to reduce the losses in the system. The operator could make a calculated decision occasionally if the benefit could be achieved from a small number of switching steps.

3.4.2.1.2.3 Demonstration of Loss Reduction Functionality

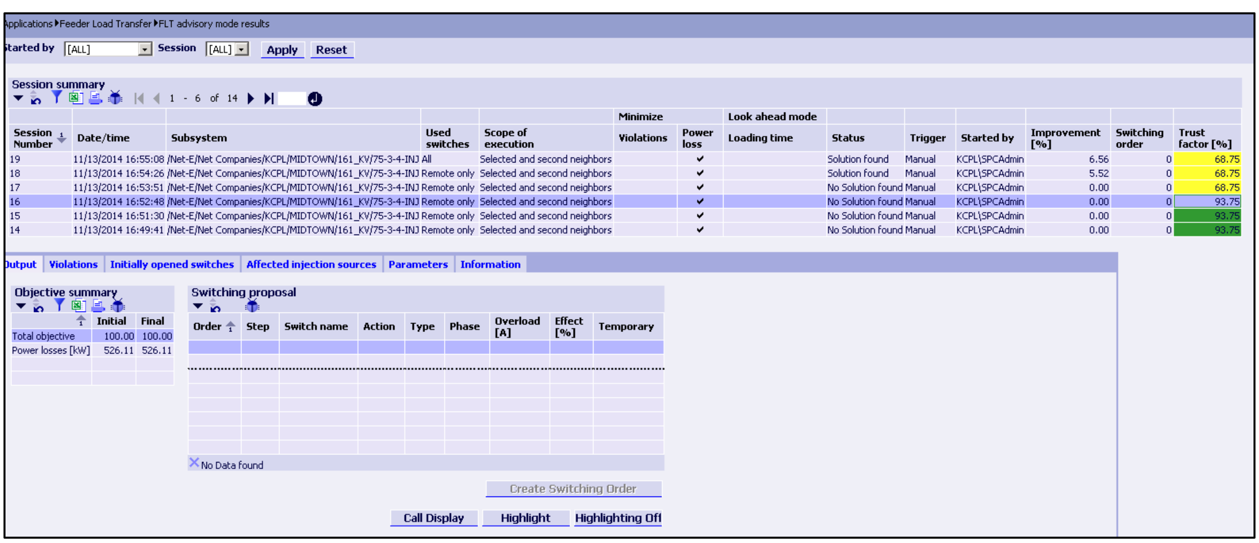
The application did not yield any results using remote switches in the real-time system, as the system was optimized for the lowest losses. The application generated a number of results using all switches but the feasibility of FLT depends on its ability to use automated switches to reconfigure the circuit for the stated objective (minimize losses, in this case). In order to further analyze the application and assess its efficiency, the application was tested in study mode, using historical and current load models and real time data.

The primary intent here was to prove that FLT would reconfigure a system using automated switches to reduce losses, however small they might be, depending on the parameters. An indirect approach was taken where the system was put in an abnormal configuration. The study case created an image of the real-time system using real-time status, peak data, or historical data as specified by the operator and can be used for predictions and simulations. The operator can then configure the system as decided by operating the switches. The normal configuration was previously established as the optimal configuration by FLT, as there was no alternate solution. This would be verified in this case. The configuration of the feeders would be changed to an abnormal or a configuration different from the real-time system. FLT, when executed for the study mode, would be expected to recommend reverting to a configuration similar to the real-time configuration.

FLT was run in study mode, both prior to changing the configuration and after changing the configuration.

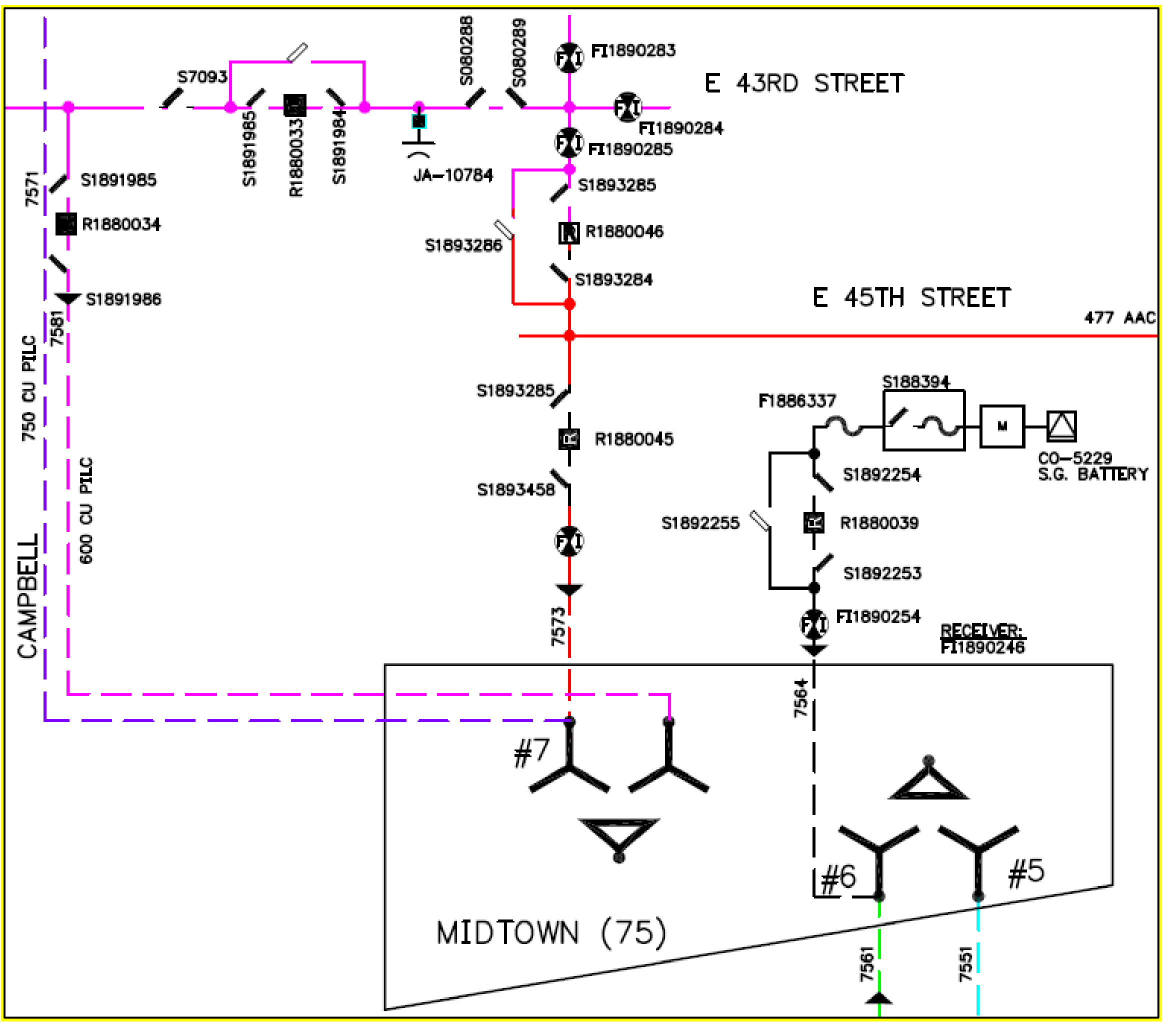
FLT – when run in study mode for the normal configuration and using only automated switches – did not generate a solution, which was expected and similar to the real-time instance. The following screenshot (Figure 3-56) displays the result.

Figure 3-56: Study Mode – Minimize Losses (Normal Configuration)



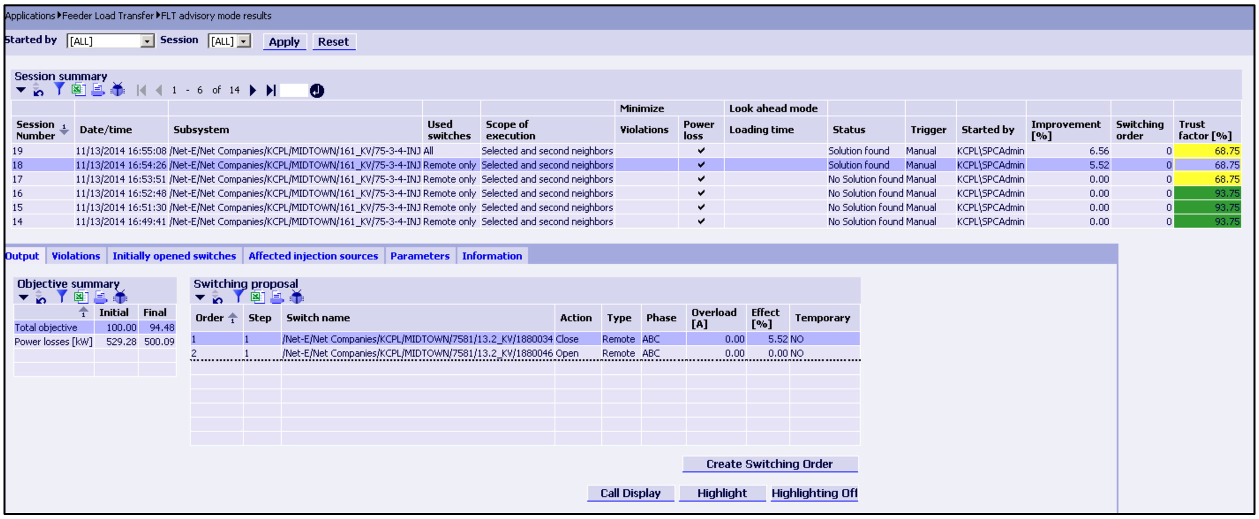
The One Line diagram (Figure 3-57) represents a section of the two (2) smart grid feeders whose configurations were changed in the study case. The feeder 7573 was fed through Isolation switch 1880045 and the feeder 7581 was fed through Isolation 1880034. The two feeders could be tied together by closing Tie Switch 1880046. In the normal configuration, both the isolation switches would be closed and the Tie Switch would be in the Open state. For this demo the feeder 7581 was fed from 7571 by closing tie 1880046 and opening 1880034. This produced a larger load on feeder 7573, thus increasing the electrical losses; it should be noted that only the line section between the substation and toe 1880046 saw the substantial increase in load and an increase in losses. The increase in losses was not substantial, but as an alternate configuration would be available where the losses would be comparatively less. FLT must suggest a switching solution that would revert the system back to the original configuration.

Figure 3-57: Feeder 7573 & 7581 Tie Configuration



FLT in study mode, when executed for the abnormal configuration as described above, generated a switching solution to reduce losses. The result is represented in the following screenshot, Figure 3-58.

Figure 3-58: Study Mode – Minimize Losses (Abnormal Configuration)



Switching proposal

Order	Step	Switch name	Action	Type	Phase	Overload [A]	Effect [%]	Temporary
1	1	/Net-E/Net Companies/KCPL/MIDTOWN/7581/13.2_KV/1880034	Close	Remote	ABC	0.00	0.99	NO
2	1	/Net-E/Net Companies/KCPL/MIDTOWN/7581/13.2_KV/1880046	Open	Remote	ABC	0.00	0.00	NO

Objective summary

	Initial	Final
Total objective	100.00	99.01
Power losses [kW]	413.06	408.95

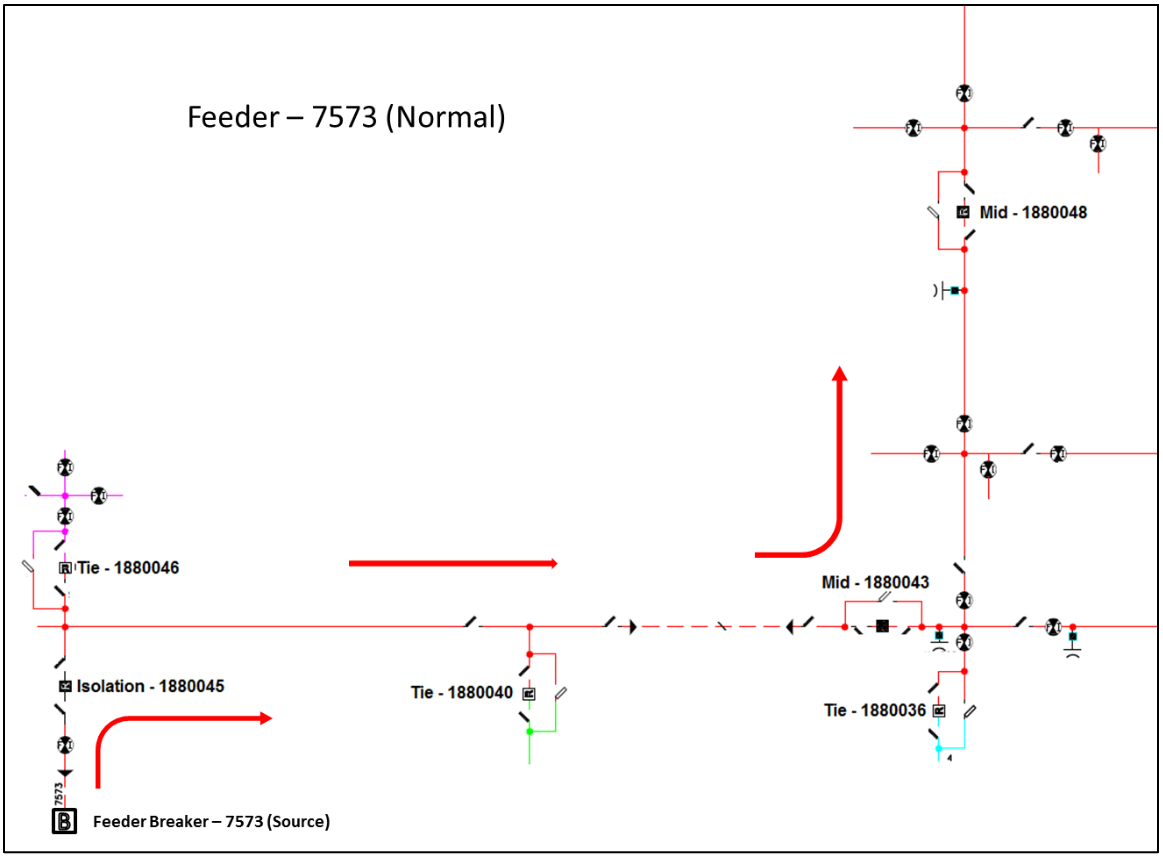
The exact switching proposal recommends switching back to the normal configuration by closing the Isolation switch 1880034 and Closing Tie 1880046 without any outages and a loop for a small period. The loss reduction by this switching change is close to 1%. The loss reduction, though not substantial, was still considerable as it would be realized using automated remote switches at minimal to zero operational cost. The application recommended a solution that would minimize losses using automated switches, even for the smallest reduction in losses using automated switches. When used on an entire power system consisting of several substations and a large number of automated switches, the application would have a substantial impact in reducing losses on daily, weekly, or seasonal basis.

3.4.2.1.2.4 Demonstration of Violation Minimization

The FLT application, apart from minimizing losses, had another primary objective: to reduce violations on the system. This functionality was demonstrated by simulating an overload on the real-time system. The purpose of this objective was to monitor the system for any violations on any lines, switches, or transformers. FLT could be run cyclically on a routine basis and also be configured to trigger when a violation was detected to minimize the violations. A violation was generated in case of a limit violation by any parameter, the most common of which would be overloading of a line where the current exceeded the line limits. Another example would be a voltage limit violation, where the voltage on the section would exceed the preset voltage limits. In case of these violations, the FLT application would work to reconfigure the system within its capabilities to reduce the violations.

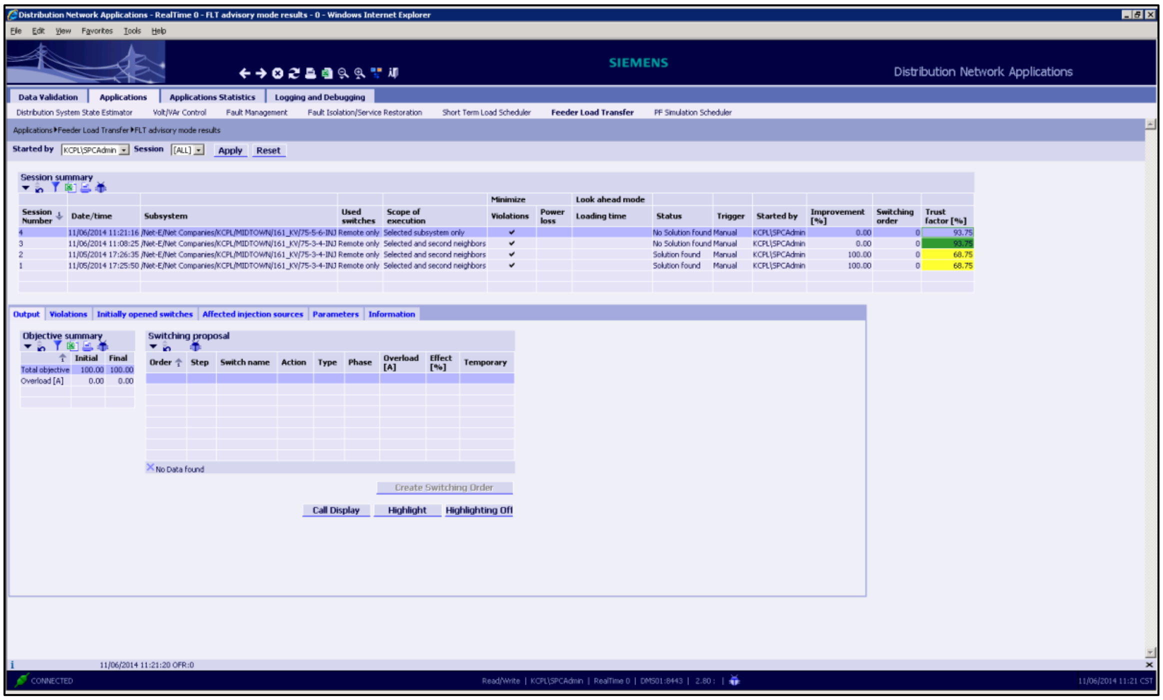
For the demonstration of this objective functionality, a line overload was simulated as the violation to be mitigated. The following diagram (Figure 3-59) has the one line for feeder 7573 used for this demonstration. The feeder was fed from feeder breaker 7573 as the main source from the substation, with the power flow represented by red arrows. The feeder had three (3) alternate sources, apart from the feeder breaker through Tie Switch 1880046 (Feeder 7581), Tie Switch 1880040 (Feeder 7551) and Tie Switch 1880036 (Feeder 7561). The later these tie switches would normally open as shown below.

Figure 3-59: 7573 – One Line Diagram with All Switches



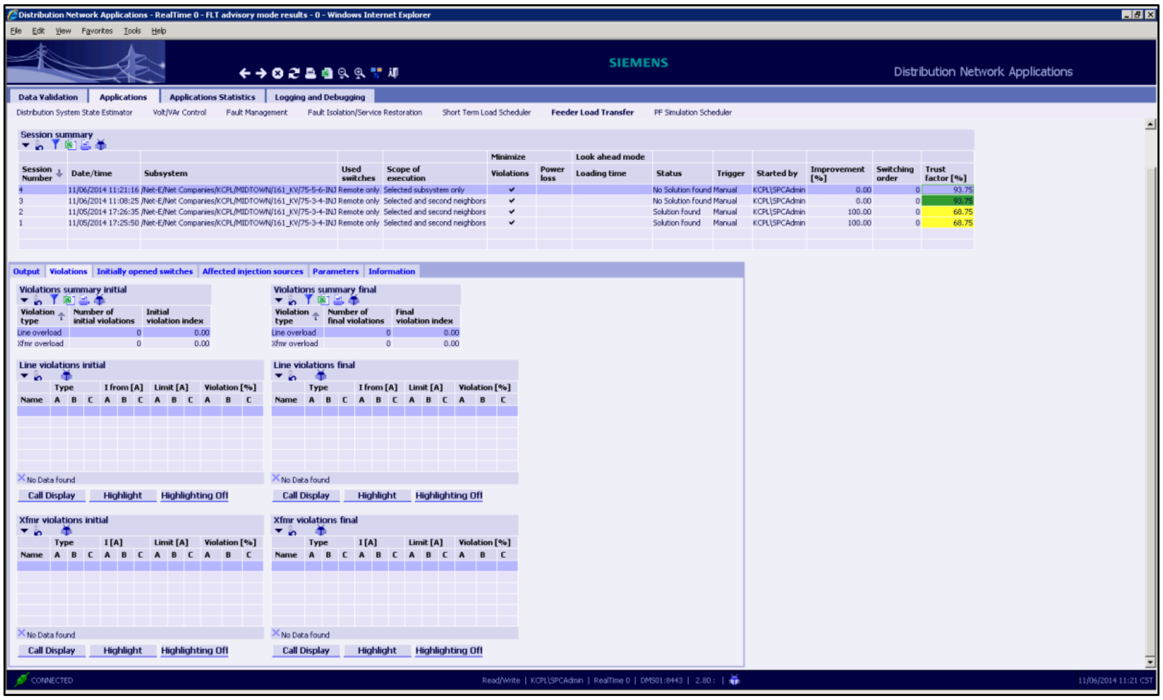
FLT was run with the minimize violation objective prior to simulating the overload to ensure that the system was already optimized and that there were no pre-existing violations on the system. The first screenshot, in Figure 3-60, shows the FLT results in normal configuration. As seen below FLT does not make any recommendation as the system is in an optimum configuration.

Figure 3-60: Result – Minimize Violations (No Overload)



The following screenshot, Figure 3-61, shows the violation tab of the FLT result where the number of violations is zero.

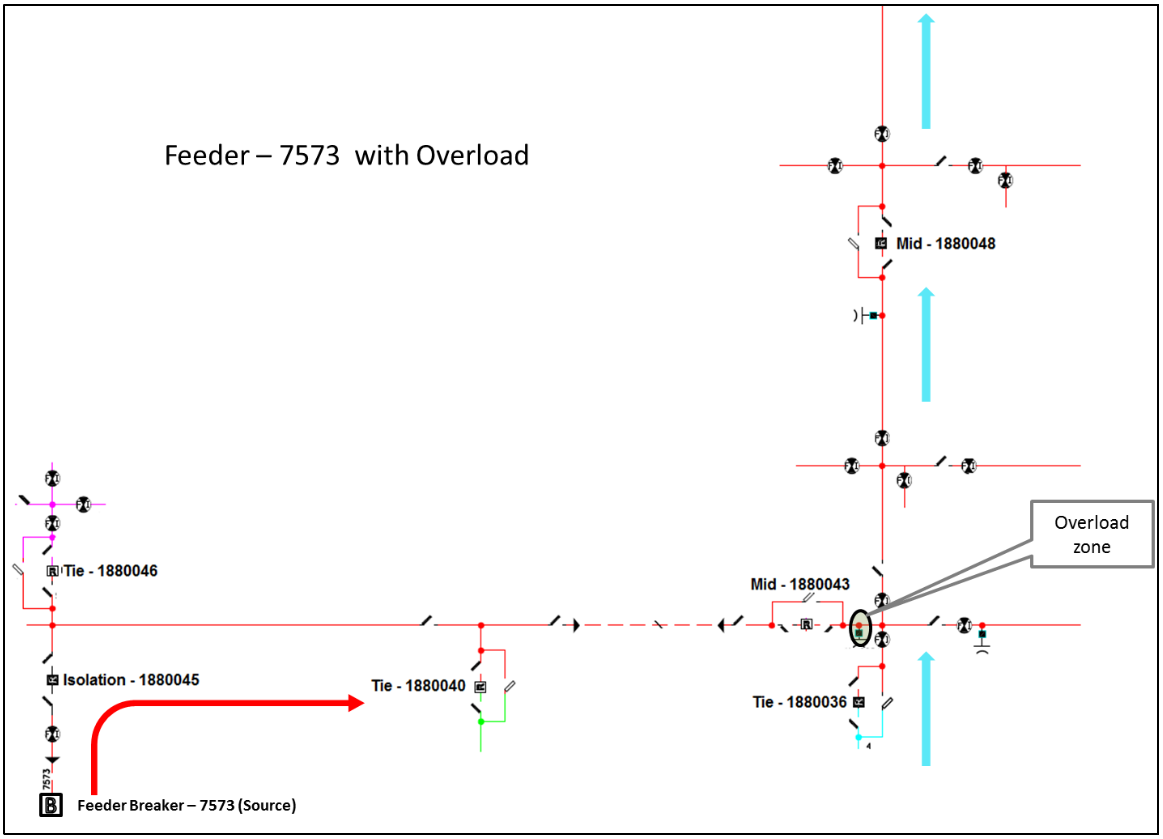
Figure 3-61: Results Violations Tab – Minimize Violations (No Overload)



An overload was simulated on the feeder next to switch 1880043 in the location marked in Figure 3-62. The limit on this specific line section was substantially lowered to cause the line to overload. State Estimator detected the overload on the line section and triggered FLT in violation minimization mode.

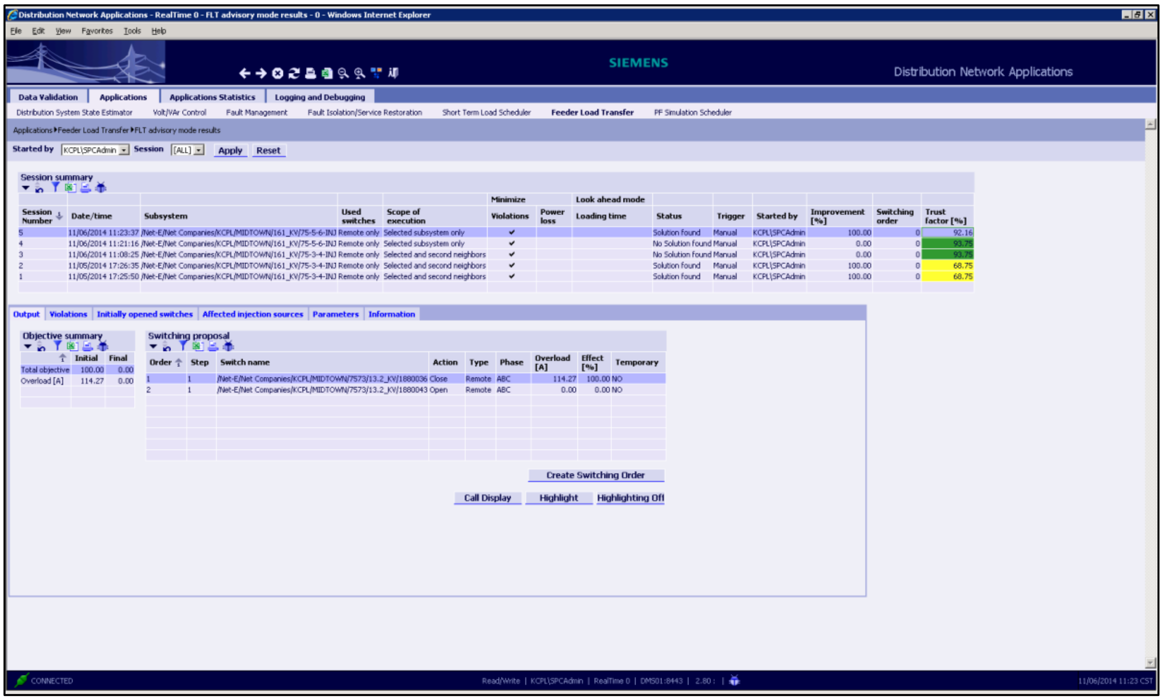
The feeder has three (3) alternatives (Tie switches), as mentioned before, but the load on overloaded line section could be reduced only by opening switch 1880043 and using switch 1880036 as the alternate source as shown below.

Figure 3-62: 7573 – One Line Diagram with Overload Location



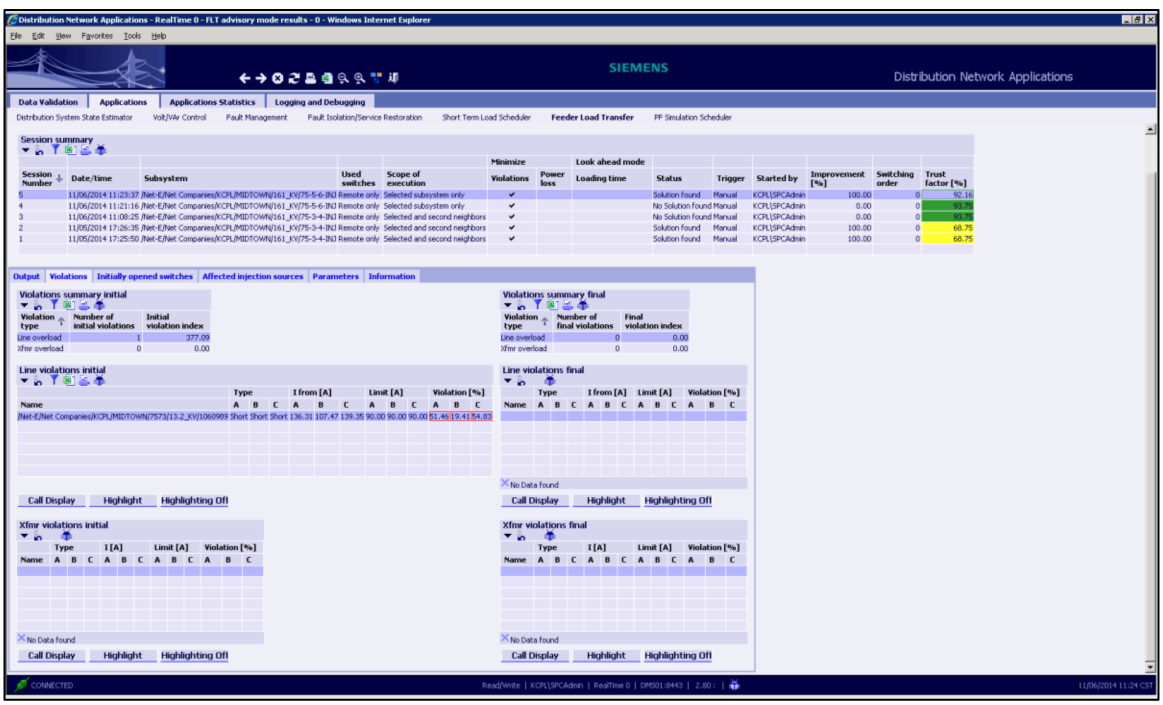
The reduction in the limit triggered State Estimator, which detected a violation on the line section in light of the reduced limit and triggered FLT. The trigger parameters for FLT were set to the minimize violation objective. The first screenshot, in Figure 3-63, shows the result from FLT: Close 1880036 and open 1880043. The result was exactly as expected. This result ensures that the current flowing through the overloaded line section is considerably reduced.

Figure 3-63: Result – Minimize Violations (with Overload)



The following screenshot, Figure 3-64, shows the violations before and after (estimated) the FLT execution. There is a single three-phase overload before the execution, an overload that was eliminated after the FLT result was executed.

Figure 3-64: Results Violations Tab – Minimize Violations (with Overload)



3.4.2.1.2.5 Issues and Corrective Actions

The following issues and corrective actions were encountered during the performance of the FLT operational demonstration and analysis.

Table 3-44: Issues and Corrective Actions

Issue	Corrective Action
• Concern from Operations for real-time automated network reconfiguration.	• The application was run in Study mode and overloads were simulated, thus eliminating the need for real-time reconfiguration.
• Feeders were already in optimized configuration.	• The application was run in study mode; feeder configurations were changed in study mode to generate solutions.

3.4.2.1.3 Findings

The results obtained in the execution and analyses of FLT operational demonstration are summarized in the sections below.

3.4.2.1.3.1 Discussion

The results obtained in the execution and analyses of the Feeder Load Transfer operational demonstration are summarized in the sections below.

The FLT application was run on the five (5) highly automated SmartGrid circuits throughout the operational test period. The major observation was that the smart grid area at KCP&L was already optimized with the limited number of switching options available using remote switches. The application was verified, however, by reconfiguring the feeders to a high-loss configuration, whereby it recommended to be switched to the normal optimized configuration to minimize losses.

The FLT application had a number of switching solutions using both remote and manual (nontelemetered) switches to minimize losses. Manual switching comes with the additional cost of a switching crew being deployed to execute the manual switching. Among observations drawn from results:

- The solutions presented were transient in nature (changing daily or weekly) and would require multiple daily or weekly switching operations to keep the system continually optimized.
- The solutions involved a large number of switching steps and the objective benefit from most of the solutions was not high enough to warrant sending out a field crew and to execute the switching order.

The cost of deploying a field crew to execute a large number of the switching steps would offset the benefit from the reduction of losses. On several occasions it was observed that a small subset of the switching steps would generate more than 80% of the benefit. The operator could make a calculated decision to execute a subset of a switching plan if it was suggested repeatedly over prolonged period (seasonal/monthly/weekly) and would produce a high-objective benefit.

The FLT application relies on a large number of interconnections and ties between feeders, transformers, and substations to continually configure the system and reduce losses on a daily, monthly, or seasonal basis. As such the FLT application would be better suited to be executed centrally across the entire system of substations rather than in a distributed manner at a substation or transformer. The application did not serve its major purpose when run in a distributed manner, as the number of options to a specific configuration were drastically reduced and compounded with the fact of availability of remote switching, ties, etc., at a specific substation.

FLT could also be used as a planning tool for automated switch installation; FLT could be used to identify manual switches that could be replaced with automated remote switches to provide maximum configurability for a feeder and overall system. As mentioned previously, FLT generates substantial switching using all switches. These switching suggestions could be used to identify optimum locations for replacing a manual switch with a load break or mechanized automated switch.

3.4.2.1.3.2 Expectations vs. Actuals

The following table provides a comparison of the Expected Results and the Actual Outcomes for the Feeder Load Transfer operational test.

Table 3-45: Expected Results vs. Actual Outcome

Expected Results	Actual Outcome
• FLT analysis makes changes to the Normal circuit configurations to be more efficient and reduce distribution system losses.	• FLT did not make any recommendation in the normal configuration of the circuit using remote switches, as the circuit was already optimized. • FLT did make recommendation to move back to above normal configuration when the circuit was in an abnormal configuration.
• FLT may identify real-time, daily, or seasonal reconfigurations that would be more efficient and reduce distribution system losses.	• FLT did not identify real-time, daily, or seasonal reconfigurations using only remote switches. • FLT did identify real-time, daily, or seasonal reconfigurations using remote and manual switches, but these switching recommendations were not used as the effort and cost expended to execute these manual operations by field crews would the benefit from reduction of losses.

3.4.2.1.3.3 Computational Tool Factors

The following table lists the values derived from the Feeder Load Transfer operational test analysis that will be used as inputs to the SmartGrid Computational Tool.

Table 3-46: Computational Tool Values

Name	Description	Calculated Value
Reduced Electricity Losses	Average losses for the portion of the distribution system impacted by the project. (%)	0%
Deferred Distribution Capacity Investments	The size of the generation investment deferred as a result of reduced losses.	0 MW

3.4.2.1.4 Lessons Learned

Throughout the conduct of the operational testing and analysis of the FLT function, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- Centralized Implementation – FLT is more compatible with a centralized implementation rather than a distributed implementation. FLT was designed as a self-healing application for the SmartGrid circuits, but its benefits would have been realized further if implemented on a system-wide level.
- Recloser Placement (Tie Switches) – The methods for placing tie reclosers on a system could be further optimized using the application itself. Tie reclosers are extremely crucial for FLT to generated impact; a system with high number of tie switches and associated normally closed switches must be used to demonstrate FLT.
- Loss Calculation – AMI data aggregation with high accuracy is essential to accurately calculate the electrical losses and theft on the power system. For this demonstration, the losses calculated by State Estimator were considered but the availability of highly accurate feeder based AMI aggregation would have enabled a comparison with feeder head data, thus resulting in more accurate loss calculation.
- Study Case Usage – The Study case environment on the DMS proved to be a vital tool in testing the various applications, including FLT. Study Case environments must be given high priority during the implementation phase to foster smooth testing and implementation of distribution applications.
- Manual Switching Effectiveness – A new parameter needs to be introduced into the application when utilizing manual switches that compares the switching costs and the objective benefit. That would improve situational awareness and give the operator adequate data to make an intelligent decision about whether to execute a switching decision or not.

3.4.3 Automated Feeder and Line Switching

Automated feeder switching is realized through automatic isolation and reconfiguration of faulted segments of distribution feeders via sensors, controls, switches, and communications systems. These devices can operate autonomously in response to local events or in response to signals from a central control system.

3.4.3.1 Fault Isolation and Service Restoration

Fault Isolation and Service Restoration is a demonstration of one aspect of the Automated Feeder and Line Switching function.

3.4.3.1.1 Overview

The following sections provide an overview of the operational, demonstration, testing, and evaluation methodology used for the Fault Isolation and Service Restoration operational demonstration.

3.4.3.1.1.1 Description

Fault isolation, fault location, circuit monitoring devices, and automatic circuit reconfiguration equipment was deployed on the 11 SmartGrid distribution circuits. This included two-way communications to enable system operators to continuously monitor and operate this equipment remotely. The systems also automatically identified circuit faults and, when possible, isolated them to smaller sections of the circuit. Remaining sections of the circuit were restored automatically without human intervention. Additionally, system operators received alerts regarding the faulted section and deployed field crews directly to the failed equipment, avoiding timely fault searching.

3.4.3.1.1.2 Expected Results

This operational demonstration was expected to yield the following:

- Reliability would improve, resulting in significant reductions in SAIFI and SAIDI. It is estimated that SAIFI could be reduced by 20%, SAIDI by 30%.
- Operational costs would be reduced as manual switching would be executed remotely and fault locations would reduce fault searching time. It is estimated that manual switching, per circuit, could be decreased by three to six truck rolls per year.

3.4.3.1.1.3 Benefit Analysis Method/Factors

The DOE SGCT was used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits were quantified.

- Reduced Sustained Outages
- Reduced Restoration Costs
- Reduced T&D Operations Costs
- Reduced CO_2 Emissions

Benefits were calculated using SGCT formulas. The following factors were measured, projected or calculated during the application operation and/or demonstration.

Reduced Sustained Outages

- SAIDI (base & projected)

Reduced Restoration Costs

- Avoided Distribution Restoration Costs ($) (crew outage troubleshooting)

Reduced T&D Operations Costs

- Avoided Distribution Operations Costs ($) (crew response to fuse level outages)

Reduced CO_2 Emissions

- Avoided Truck Rolls

3.4.3.1.1.4 Testing Methodology

The following points provide an overview of how the operational demonstration and testing for this application was accomplished:

- KCP&L's legacy OMS continued to be used by the Distribution Dispatcher to work lights-out and other trouble calls.
- The legacy OMS continued to record all outage events and restoration efforts.
- The SGDP OMS was used in study mode to perform an after-the-fact analysis to determine how the FISR application would have impacted outage response and restoration efforts.

3.4.3.1.1.5 Analytical Methodology

The following points provide an overview of the analytical methods that were used to evaluate the impact and benefits of this application:

- In the after-the-fact analysis of each major event the following data were calculated to determine how the FISR application functions:
  - Major Event - Number of Customers Affected
  - Major Event - Number of Customers Affected without FISR
  - Major Event – Total Customer Outage Hours (hours)
  - Major Event – Total Customer Outage Hours without FISR (hours)
  - Major Event – Total Restoration Time (hours)
  - Major Event – Total Restoration Time without FISR (hours)

3.4.3.1.2 Plan Execution and Analysis

The following sections provide details regarding the functional tests performed, data collection and analysis performed for the FISR operational demonstration.

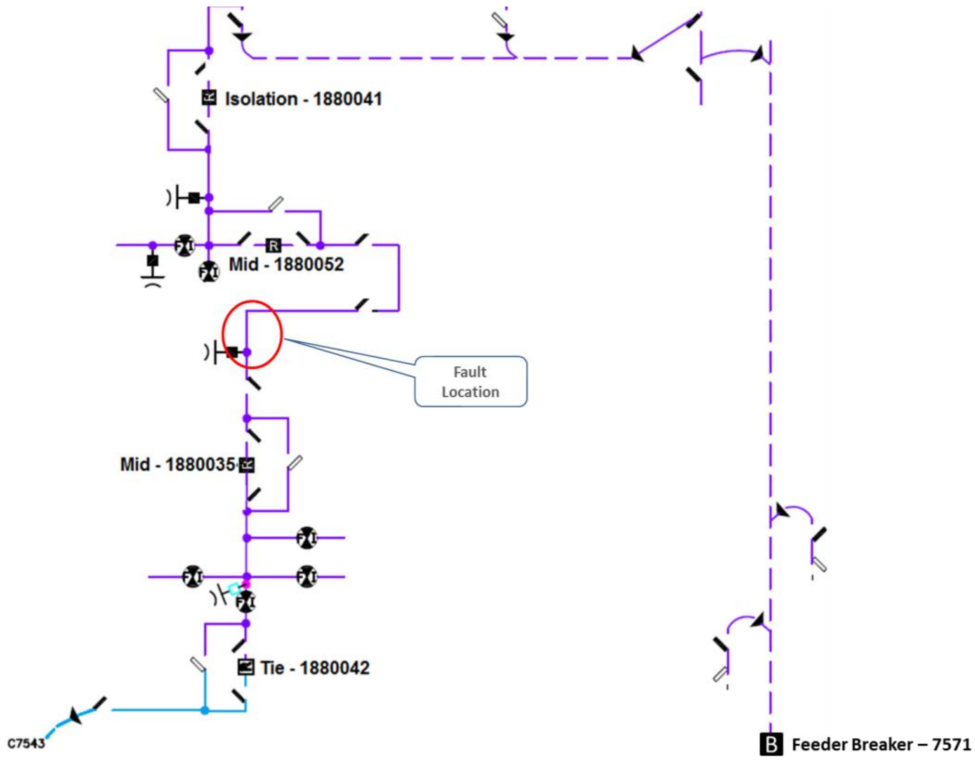
3.4.3.1.2.1 Functionality Demonstration

The FISR application generates optimal switching solution for managing faults or planned outages for equipment. The application ensures that the switching solution is practical in that no limits are violated by running State Estimation/Power Flow for each step. The application computes a switching solution, isolates the faulty area as needed, and then restores power to as many customers as possible. Quick detection of faults (breakers/relays/FCIs) and highly automated switches enable the application to perform switching momentarily and reduce outage times substantially.

A real-world demonstration was conducted to verify and validate FISR application functionality and associated SmartGrid infrastructure. The application was not fully operational in automated mode over the entire demonstration period, and the demonstration proved opportune for validating the application. The demonstration was distinct in the fact that every aspect of the demonstration was virtually similar to an actual fault; the only difference was the planned nature of the fault.

The KCP&L's SmartGrid and distribution operations teams were instrumental in executing the demo and were closely involved during the entire demonstration. The teams identified a feeder where the requirements for both teams were met. The teams selected feeder 7571 (Figure 3-65, below) for the fault as there was provision for fault isolation, immediate restoration, and restore to normal on this feeder to display all functions of FISR; a section of the feeder was safe and an ideal location for creating a real-world fault.

Figure 3-65: One-Line Diagram – Feeder 7571



Feeder 7571 has four reclosers: one (1) isolation, two (2) mid-circuit and one (1) tie recloser. As shown in the above diagram, the feeder is fed from the substation through feeder breaker 7571 with an alternate source available through tie recloser 1880042 from feeder 7543 (bottom left).

The demonstration was planned to mimic a real-world fault in all aspects, with the sequence of events – from fault to full restoration – was exactly as in a real-world fault situation. A two-phase-to-ground fault was created on feeder-generating fault currents greater than 5700 A to trigger the sequence of events involved in managing a fault on a feeder using the FISR application. The demonstration was conducted with the application in open-loop mode, meaning the application would suggest switching for the operator to validate and execute. The closed-loop or full automated mode was not used in this case, as the application had not been thoroughly tested in automated mode and the operations group was apprehensive to implement the application without user intervention. The DMS and FISR application response and the sequence of events for the demonstration are as follows:

Sequence of Events

Fault Occurs: The field operations crew created a fault on the overhead section of the feeder marked in the one line diagram (Figure 3-65). The upstream reclosers (1880041 and 1880052) and the feeder breaker (7571) saw the fault but, as per the set coordination, the immediate upstream recloser (1880052) tripped on the two-phase fault. The fault generated an outage for 777 customers.

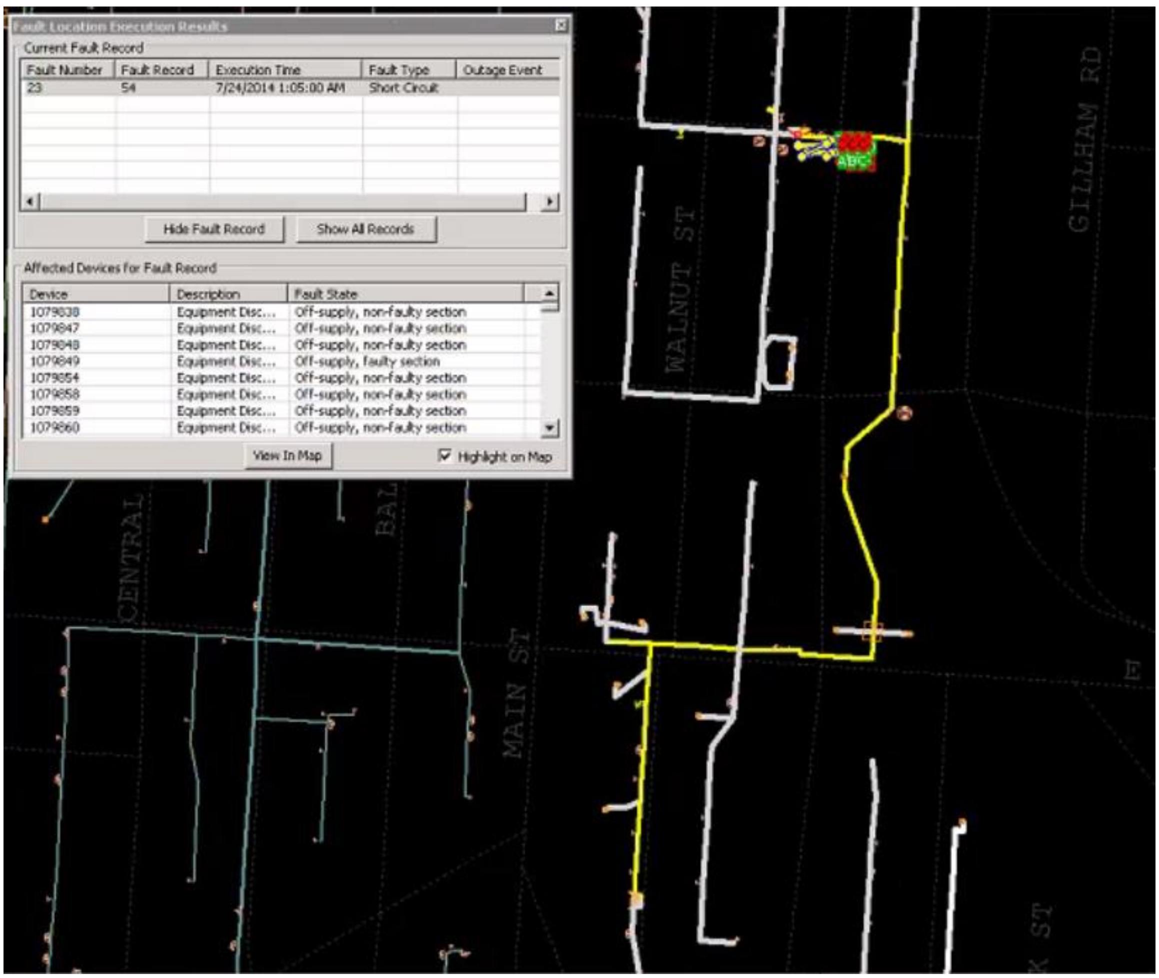
Fault Location Identification: The operator then ran the fault location application for the above specific event. The application highlighted the faulty section on the feeder using data from all automated switches and FCIs with the appropriate protection coordination.

The application determined the location using the following factors:

- Recloser 1880052 tripped – Fault was downstream of recloser 1880052. Since the recloser tripped, the location was determined to be upstream of any fuses, as a fuse would have blown to isolate the fault.
- Recloser 1880035 did not trip – The fault was upstream of recloser 1880035. (Fault is between 1880035 and 1880052.)
- There were no FCIs in this section but the presence of FCIs, and their operation or nonoperation, would further assist in narrowing down the fault location.

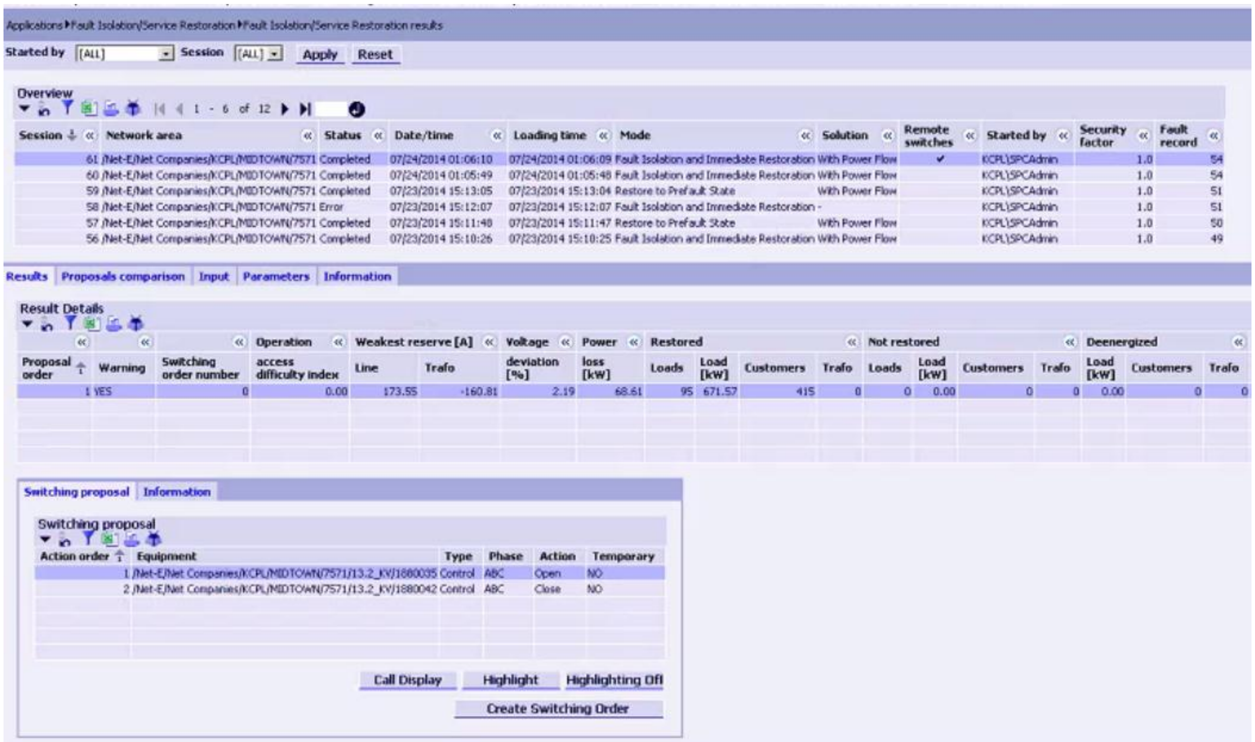
Based on the above factors, the application determined that the fault was on the backbone of the feeder between 1880052 and 1880035 as shown in Figure 3-66 below. On screen the faulty section is highlighted in yellow; the line section blinks in yellow, providing considerable situational awareness to the operator to identify the location and subsequently isolate the outage and restore service.

Figure 3-66: Fault Location App Screenshot



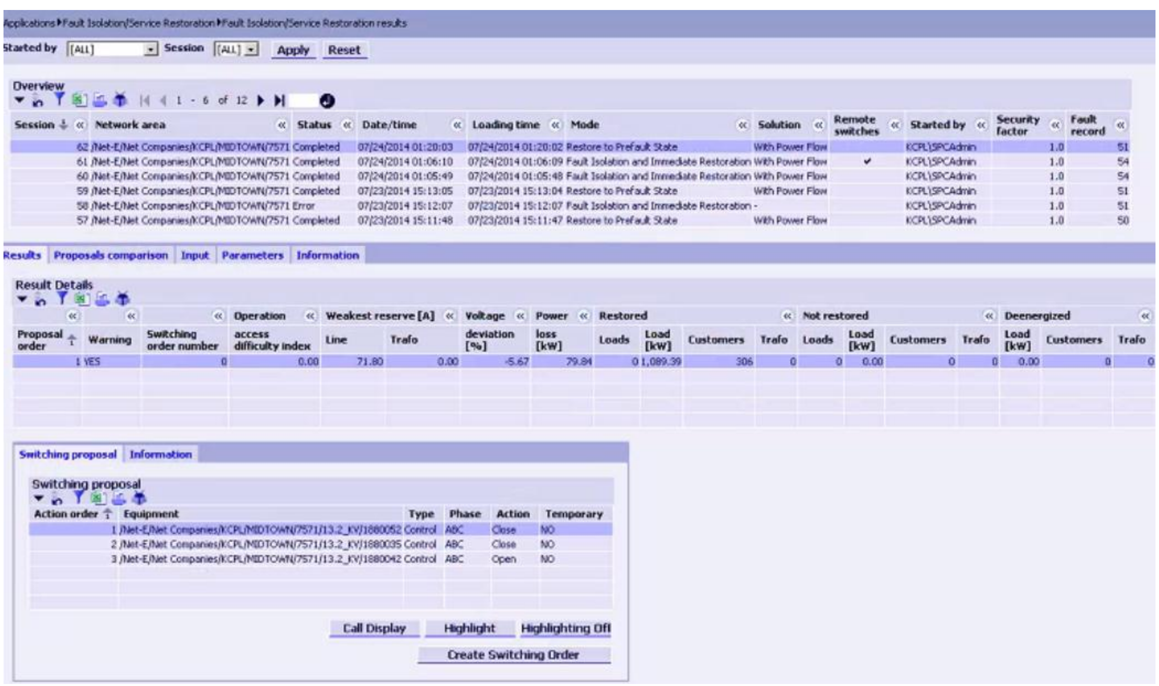
<u>Fault Isolation and Partial Restoration</u>: After confirming the location of the fault, the operator executed FISR in isolate-and-partially-restore mode, generating the results as shown in Figure 3-67. The results suggested opening 1880035, to isolate the faulty section, and closing tie 1880042, to restore the nonfaulty section through an alternate feeder. The operator verified and executed the switching steps, restoring power to 434 customers out of the 777 that were out.

Figure 3-67: Isolation and Partial Restoration



Restore to Prefault: Once the fault was cleared, the outage event was closed in the application and FISR was run in restore to prefault mode, with results shown in Figure 3-68.

Figure 3-68: Restore to Normal



The application suggested closing 1880052, which would restore power to the customer still under an outage. The application then suggested closing 1880035 and putting feeder 7571 in loop with 7543 as the tie remained closed. The application then suggested opening tie 1880042 to break the loop without causing any loss of power and switching back to the prefault radial configuration.

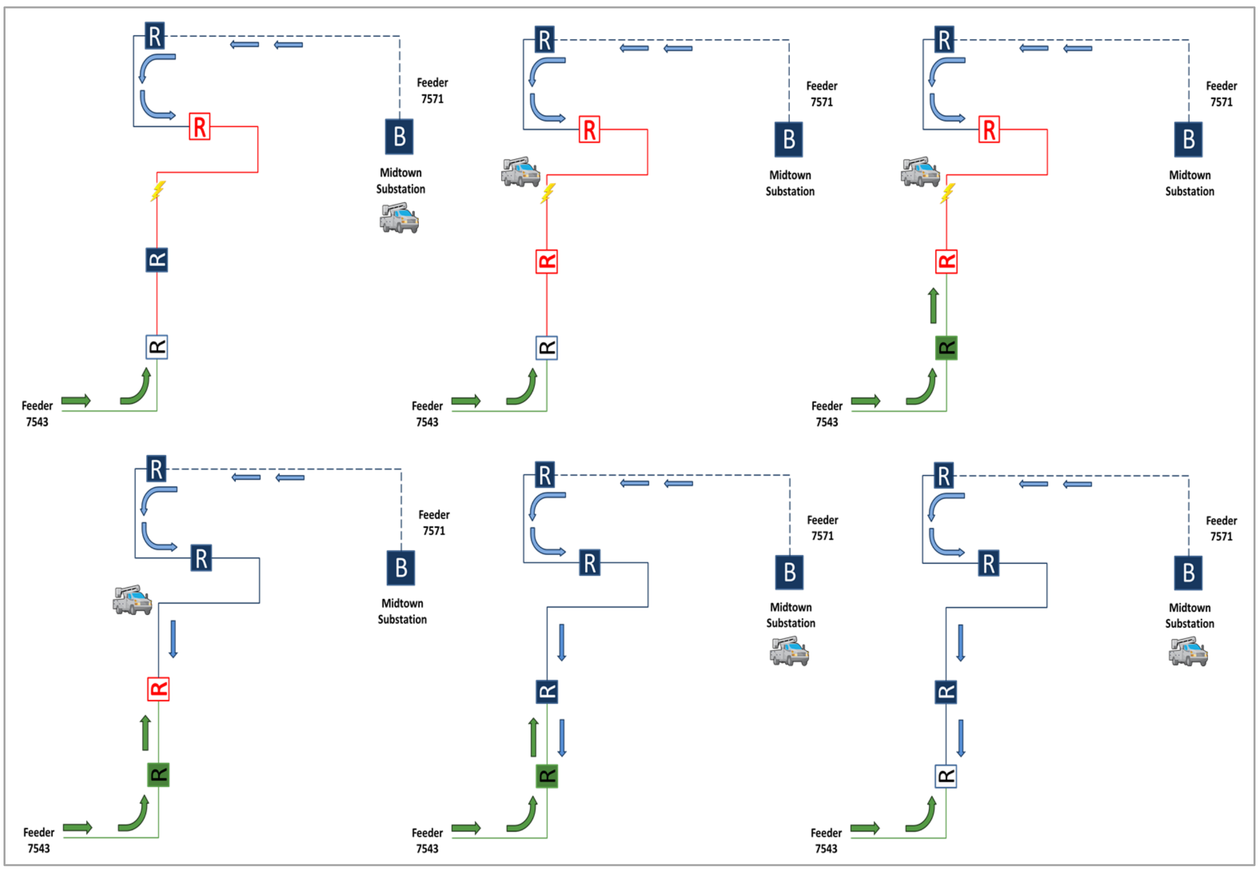
The timeline for the demonstration for each of the switching steps is presented in Table 3-47, below, with durations for each step in the process.

Table 3-47: FISR Demo Timeline

	Event	Action	Time (07/24/2014)	Step Duration
1a	Fault Occurs		1:04:42 AM	Start
1b	Fault Opened	Trip Recloser – 1880052	1:04:42 AM	00:00
2a	Fault Area Located & Isolated	Open Recloser – 1880035	1:06:50 AM	02:08
2b	Partial Restoration	Close Recloser – 1880042	1:07:50 AM	01:00
4a	Full Restoration	Close Recloser – 1880052	1:21:39 AM	13:49
4b	Restore to Normal - Start	Close Recloser – 1880035	1:21:57 AM	00:18
4c	Restore to Normal - Complete	Open Tie Recloser – 1880042	1:22:23 AM	00:26

Figure 3-69 below shows the different stages of the demonstration and the switching steps associated with FISR once the recloser had tripped on the fault.

Figure 3-69: Switching Sequence for Demonstration



The demonstration for the FISR application was conducted to demonstrate the capabilities of the application and to analyze the time saved by using the FISR application. It must be noted that the demonstration involved executing the FISR application in an open-loop environment, with constant verification of steps by the operator and additional checks in the field and in the control center. FISR can also be run in the closed-loop environment, where the application would execute triggers automatically upon occurrence of a fault and would work to isolate and partially restore service by switching devices immediately without operator intervention. Upon clearance of the fault, an operator would be required to close the fault in the application; FISR immediately would work to restore to normal by executing the appropriate switching again without manual intervention.

During the demo, it was observed that the last two switching steps during restoration took 18 seconds and 26 seconds, respectively. The steps involved the operator reviewing the switching step, executing the command and confirming it on DMS, confirming with the field, and then moving on to the next switching step. A command extracted from the DMS and sent to a device required less than a second for a response, nearly instantaneous to the human eye. Considering such performance, and factoring in even a potential for delay, it can safely be estimated that, in a closed loop, each step would be executed within 10 seconds. Considering that the fault rectification time would remain the same, as FISR would not affect those times, the fault would be isolated and the feeder partially restored much faster if FISR was run in fully automatic or closed-loop mode.

The FISR demonstration events, when compared to a similar event occurring on the same feeder without smart-grid infrastructure, would generate a much larger outage in terms of time and customers affected, and would affect the entire feeder. The fault would trip the substation feeder breaker, thus de-energizing the entire feeder. A field crew would then be dispatched to identify the type (overhead or underground) of fault. Upon ruling out an underground fault, the crew then would:

- Patrol the entire feeder to look for a faulty section;
- Locate the faulty section and identify isolation switches on the feeder to isolate it;
- Work to restore power to the remaining sections of the feeder by closing the substation breaker upstream of the faulty section and a manual tie switch downstream of the faulty section, if available, to partially restore power to remaining sections of the feeder;
- Perform similar manual operations to restore power to entire feeder and restore to normal.

Table 3-48 compares the restoration and outage times during the demonstration (FISR in open loop) with a similar fault using fully automated FISR (closed loop) and without smart-grid infrastructure (manual). Safe estimates were used to predict the time taken for manual and fully automated FISR conditions. The time taken to rectify the fault (full restoration step) was kept the same for all three conditions, although a manual switching step in manual mode could require more time.

Table 3-48: Fault Time Comparison

Event	Demo (Open Loop)			Closed Loop (Fully Auto)			Manual (Pre-SmartGrid)		
	Customers Out	Time (Min.)	Customer Minutes	Customers Out	Time (Min.)	Customer Minutes	Customers Out	Time (Min.)	Customer Minutes
Fault Occurs	777	Start	Start	777	Start	Start	2,092	Start	Start
Fault Opened	777	0:00	0	777	0:00	0	2,092	00:00	0
Fault Located & Isolated	777	2:08	1,658	777	0:20	259	2,092	30:00	62,760
Partial Restore	343	3:08	777	343	0:30	130	343	45:00	31,380
Full Restore	0	**16:57**	4,739	0	**14:19**	4,739	0	**58:49**	4,739
TOTAL			**7,174**			**5,128**			**98,879**

It can be observed that the customer outage minutes for the manual mode is substantially higher than when using FISR in closed loop or open loop mode with reclosers.

- Customer outage minutes are reduced by 92.8, or 94.8%.
- Total outage time is reduced by 71, or 75%.

The time taken to rectify the fault is the same for all three conditions. This time is not dependent on switching and remote operations and hence can be excluded when evaluating the performance of an automated switching application. The outage times and customer minutes without fault rectification time are displayed in Table 3-49.

- Outage time is reduced by 93, or 98%.
- Customer minutes are reduced by 97, or 99%.

Table 3-49: Fault Time Comparison Without Fault Rectification Time

Factor	Demo	Auto	Manual
Total Outage Time	3:52	0:50	75
Customer Minutes	2435	389	94140

It must also be noted that although a truck roll is not avoided in this case, the labor costs and fuel spent in patrolling the circuit, identifying the fault location and manually switching the necessary switches are saved. Typically it takes about 60 minutes to identify a faulty section and isolate/partially restore for KCP&L operations, time and resources that would not be necessary using FISR.

3.4.3.1.2.2 Analysis of FISR on Actual Outages

The impact of a highly automated (closed loop) FISR application on real-time faults over the operational period will be evaluated in this section. The fault data of the five highly automated feeders was analyzed and those faults for which FISR would have an impact are discussed below. The application is directly effective on feeder backbone faults as the FISR assets — remote monitoring and switching devices (FCI, breaker and recloser) — are all located on the backbone of the feeder. Faults that are not on the backbone of the feeder will generally be isolated by fuses or local breakers that do not have telemetry and will require a field crew to isolate and restore power. These types of faults will be analyzed in a later section.

A feeder backbone fault caused on the overhead or the cable will typically be isolated by the tripping or opening of the substation breaker to isolate the fault. This results in an outage to the entire feeder until the fault has been located and isolated, then had power partially restored and then restored to normal once the faulty section has been fixed. The sequence of events was observed in the previous section. The backbone faults can be further classified into two categories: cable faults and overhead backbone faults.

Cable Faults — The SmartGrid feeders have a substantial underground section, from the substation up to the area of service where the feeder turns overhead. An isolation recloser was installed at the end of the underground section, as part of the SmartGrid infrastructure, to isolate the underground cable section from the rest of the feeder. A fault on this underground section is categorized as a cable fault and is isolated by tripping the substation breaker and thereby causing an outage on the entire feeder. The operator cannot be immediately sure if the fault was a cable fault or an overhead backbone fault, and cannot begin the isolation or restoration process until the fault type and location are confirmed.

The FISR application and its assets, particularly isolation reclosers in this case, will minimize the impact of such an outage drastically. The application identifies the fault as a cable fault based on switch data and protection coordination. The application then immediately isolates the fault by opening the isolation, and restores service by closing an available tie recloser. The sequence of events with FISR would take less than 30 seconds to execute, and would restore power to the entire feeder. The operator can then use the fault location application to verify the faulty section as the feeder cable and dispatch a crew. Table 3-50 below compares actual outage and customer data for cable faults over the past year with outage times if FISR were to be implemented.

Table 3-50: Feeder Cable Faults

Feeder #	Outage Duration (Minutes)	# of Customers	Total Customer Minutes Out	Outage Duration with FISR (Minutes)
7581	66.933	2,138	143,103.467	MOMENTARY
7573	60.050	2,607	156,550.350	MOMENTARY
7581	51.817	2,165	112,183.083	MOMENTARY
7571	13.100	1,559	20,422.900	MOMENTARY
7581	57.333	2,174	124,642.667	MOMENTARY
TOTAL	**249.233**	**10,643**	**556,902.667**	**0**

The table above shows that with FISR implemented in the SmartGrid zone, the number of customers affected for each of the faults would only see a momentary outage. The total customer minutes for the outage would be reduced drastically — from 556,902 minutes to zero minutes. Truck rolls for operations also would be reduced, with 150 (30*5) minutes of labor costs saved by field operations crews not being deployed to isolate and restore power.

Overhead Backbone Faults — The distribution feeders at KCP&L generally constitute a mix of underground and overhead sections, with the majority of the load connected on the overhead section of the feeder. The feeders in the SmartGrid area predominantly followed this configuration and were underground from the substation to the load area, where the feeder went overhead for easy accessibility for the load. A backbone fault on the overhead section in the current system is slightly trickier than a cable fault. The operator cannot immediately restore the feeder or identify the location of the fault. A field crew is required to patrol the entire feeder to identify the fault location and subsequently initiate isolation and partial restoration.

In case of FISR implementation, the recloser upstream to the fault shall trip instead of the substation breaker, thereby reducing the outage area. The application will also identify a section between reclosers where the fault occurred using the switch status, and will isolate the faulty section immediately and restore any sections of the feeder that can be restored by closing available tie reclosers. Once the application has executed the above switching steps, the operator can then dispatch a field crew to the isolated/faulty section to identify and rectify the fault. The outage for the entire feeder thus can be limited to only the section in between reclosers where the fault occurs. Table 3-51 below has a list of overhead backbone faults over the past two years on the SmartGrid feeders. The actual outage values are compared with values if FISR were to be implemented.

Table 3-51: Overhead Backbone Faults

Feeder #	Outage Duration (Minutes)	# of Customers	Total Customer Minutes Out	# of customers out with FISR	Outage Duration with FISR (Minutes)	Total Customer Minutes Out with FISR
7571	***38.017***	2,377	90,365.617	0	0	MOMENTARY
	53.017	150	7,952.500	150	15	2,250
	73.017	547	39,940.117	547	20	10,940
7551	***24.000***	649	15,576.000	0	0	0
7581	48.317	3,390	163,793.500	0	0	0
	68.317	1,362	93,047.300	1362	20	27,240
7581	***65.983***	638	42,097.367		0	0
	280.983	928	260,752.533	928	215	137,170
	324.983	442	143,642.633	442	44	40,832
	375.983	69	25,942.849	69	51	3,519
	1,365.983	50	68,299.167	50	990	49,500
7541	***31.217***	2,799	87,375.450	0	0	0
TOTAL	**2,749.8**	**13,401**	**1,038,785.0**	**3548**	**1,355**	**271,451**

The table above shows that with FISR implementation, the outage duration could be reduced from 1,038,785 minutes to 271,451 minutes (74%) and the number of customers affected could be reduced from 13,401 to 3,548 (73.5%). FISR would not have any effect on the actual time taken to fix the fault but would reduce isolation and partial restoration time to less than a minute, which would be considered momentary. The isolation switches typically used on feeders to isolate a faulty section are placed similarly to the reclosers on a SmartGrid feeder, thus negating the typical fault location and partial restoration time observed in some of the above outages. The time spent on rectifying faults for the operational crew — time highlighted above in bold italics, totaling to 159.2 minutes —, also would be reduced to zero.

Total Time Saved on Feeder Outages = 150 (Cable Faults) + 159.2 (Backbone faults) = 309.2 min

3.4.3.1.2.3 Analysis of Recloser Fast Trips

Traditionally, faults on the limbs of a feeder or on a lateral at KCP&L are isolated by a fuse blowout. The installation of fast-acting reclosers along the feeders gives the system additional ability to prevent outages from faults on the limbs of the feeder and saves fuses during temporary faults. As per existing protection coordination, a fault downstream of a fuse will be isolated by the fuse blowing out. The OMS and the operator then recognize the fault based on outage call and meter data and dispatch a crew to fix the use outage.

Outage data for fuse blowouts was analyzed for the past two years to identify patterns and any potential benefits from reclosers and FISR. It was observed that there were a substantial number of fuse outages on laterals where a cause could not be identified by a field crew, suggesting that the fuse blew out on a temporary fault. Any fault beyond the secondary transformer was not considered for this analysis. The automated fast reclosers installed as part of the SmartGrid demonstration could be used to isolate the fault prior to the fuse blowout time and reclose, thereby saving the fuse and drastically reducing the downtime for temporary faults. A temporary fault would have otherwise blown the fuse and caused an outage. In case of permanent faults, the fuse will blow prior to or after reclosing, thereby ensuring that only the customers downstream of the fuse are impacted by a prolonged outage. In such cases a field crew must be dispatched to identify the cause, rectify it and replace the blown fuse to restore power.

The usage of mid-circuit reclosers, rather than feeder head breakers, for fuse saving shall limit the momentary outage to customers downstream from that recloser, not customers along the entire feeder. Traditional fuse-saving methods involve the substation breakers and affect power quality but using mid-circuit reclosers with single phase reclosing considerably reduces the number of customers affected by a momentary outage. Table 3-52 below shows data for some of the fuse or lateral faults during the evaluation period. The on-site crew could not identify a cause for these faults as they were temporary and could be due to various reasons such as inclement weather, animals, or trees. For the purpose of this analysis, a safe estimate was made that reclosing would save the fuse and prevent an outage for one third (33%) of all the fuse outages where the fuse was refused and no cause could be identified. This estimate is highly conservative, as typically more than half of the faults without cause would be temporary.

With FISR implementation, the customer outage time and truck rolls could be reduced by 33%.

- Customer outage time reduced from 1,714,862 to 1,143,241. Minutes Saved: 571,621.
- Truck rolls and fuse blowouts reduced from 230 to 153. Truck rolls saved: 77.

Table 3-52: Fuse Laterals

Feeder #	Fuse #	Outage Duration (Minutes)	# of Customers	Total Customer Minutes Out
7581	1081668	11.22	47	527.18
7573	1089263	15.00	11	165.00
7573	1089259	19.82	17	336.88
7581	1081168	20.00	11	220.00
7551	1079672	22.52	9	202.65
7581	1081167	23.00	6	138.00
7581	1081354	23.20	13	301.60
7581	1081355	23.93	1	23.93
7561	1079398	25.23	10	252.33
7551	1079662	25.47	10	254.67
Total of All Fuse Outages		**71,573.5**	**6463**	**1,714,862**
Outage Duration with FISR 2/3rd (66%)		**47715.7**	**4309**	**1,143,241**

3.4.3.1.2.4 Impact of Minutes Saved on SAIDI/SAIFI/CAIDI

The FISR application, when implemented in open loop or closed loop mode, will have a positive impact on customer outages and reliability indices. Reliability indices, as calculated for the operational period and if FISR were implemented, shall be discussed in this section.

Table 3-53 shows SAIDI, SAIFI and CAIDI calculated for all the outages received during the evaluation period, from October 2012 to September 2014. The SmartGrid feeders serve 13,427 customers in the Green Impact Zone. SAIFI was calculated to be 3.2535. SAIDI was calculated to be 403.334 minutes. CAIDI was calculated to be 213.968 minutes for all the outages, received as shown in the table below.

Table 3-53: Indices of Received Outages (Normal and With FISR)

Indices	Normal	With FISR
System Average Interruption Frequency Index (SAIFI)		
Total Number of Customer Interruptions	43,685	21,231
Total Number of Customers Served	13,427	13,427
System Average Interruption Frequency Index (SAIFI)	3.253	1.581
System Average Interruption Duration Index (SAIDI)		
Total Sum of Customer Interruption Duration (Minutes)	5,415,570.2	3,519,713
Total Number of Customers Served	13,427	13,427
System Average Interruption Duration Index (SAIDI)	403.334	262.137
Customer Average Interruption Duration Index (CAIDI)		
Total Sum of Customer Interruption Duration (Minutes)	5,415,570.2	3,519,713
Total Number of Customer Interruptions	43,685	21,231
Customer Average Interruption Duration Index (CAIDI)	123.968	165.782

With FISR implemented in these 11 SmartGrid feeders, the total number of customer interruptions would reduce to 21,231, a decline of 51.4%. FISR would also reduce the total duration of customer interruptions to 3,519,712 minutes, a decline of 35% (bulk from backbone outages resulting in the following changes in performance metrics:

- SAIFI declined from 3.253 to 1.581.
- SAIDI declined from 403.334 to 262.137 minutes
- CAIDI increased from 123.968 to 165.782 minutes.

CAIDI increased because the FISR reduced the number of outages that that impacted a large number of customers for a relatively small period. The total outage duration for outages saved by FISR is 1,348,094 minutes, or only 24% of the total customer outage duration. But, the total number of customer interruptions reduced by 22,454 or 51% causing an increase in CAIDI.

In the next pages, the SAIDI, SAIFI, and CAIDI for the operation period for all outages (normal) and for outages with FISR implementation are plotted on a monthly basis. It can be observed that SAIDI and SAIFI are substantially reduced for all months, with the impact increased as outages increased. CAIDI increased for most months as a result of the decrease in number of short outages that affected a large number of customers.

Figure 3-70: Monthly SAIDI Before and After FISR Reduced Outages

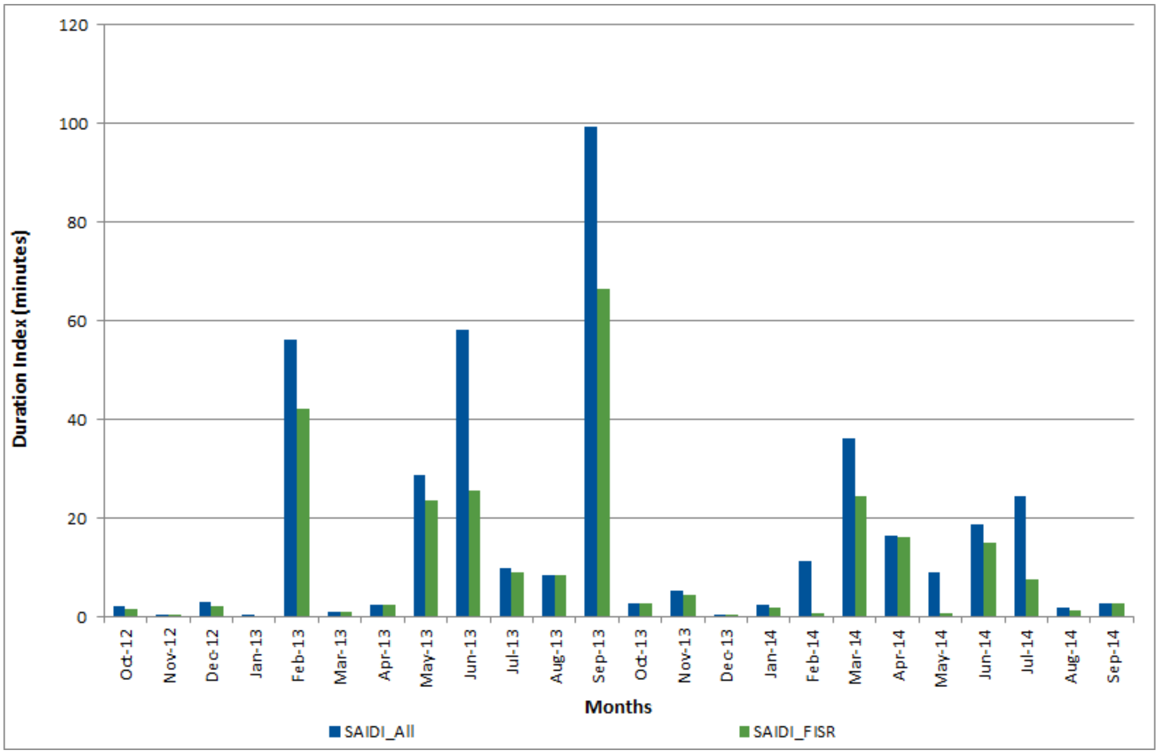


Figure 3-71: Monthly SAIFI Before and After FISR Reduced Outages

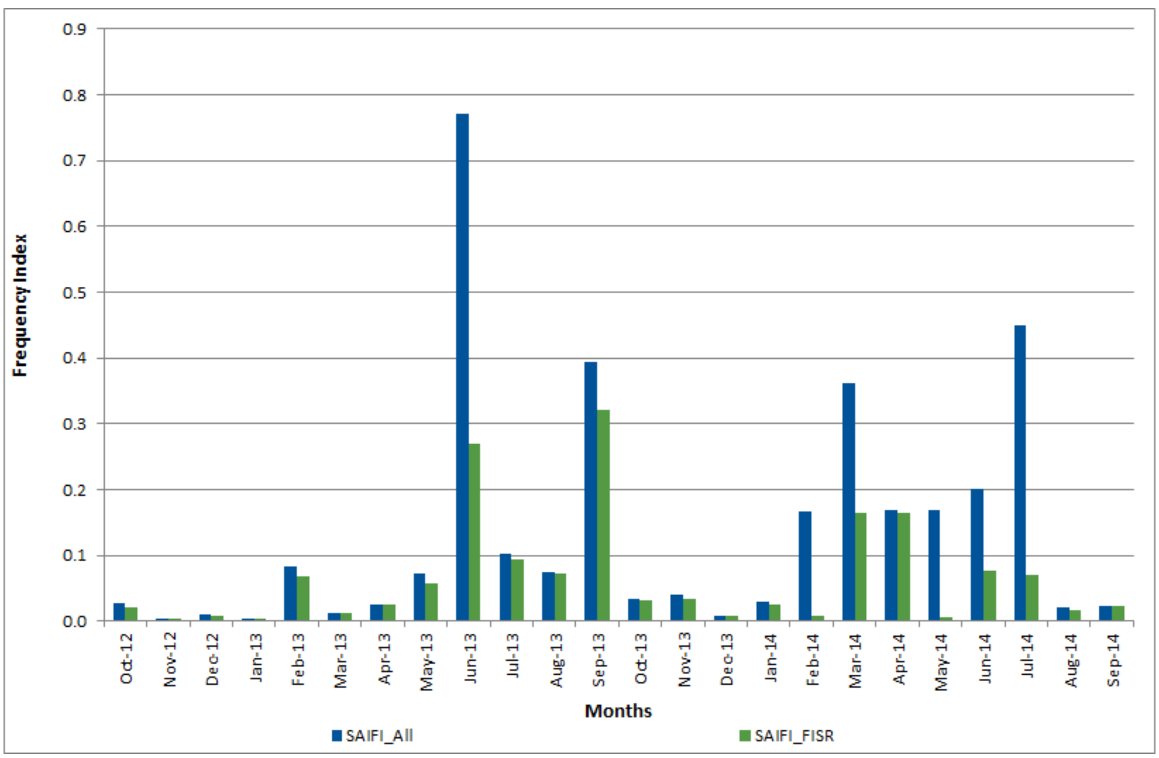
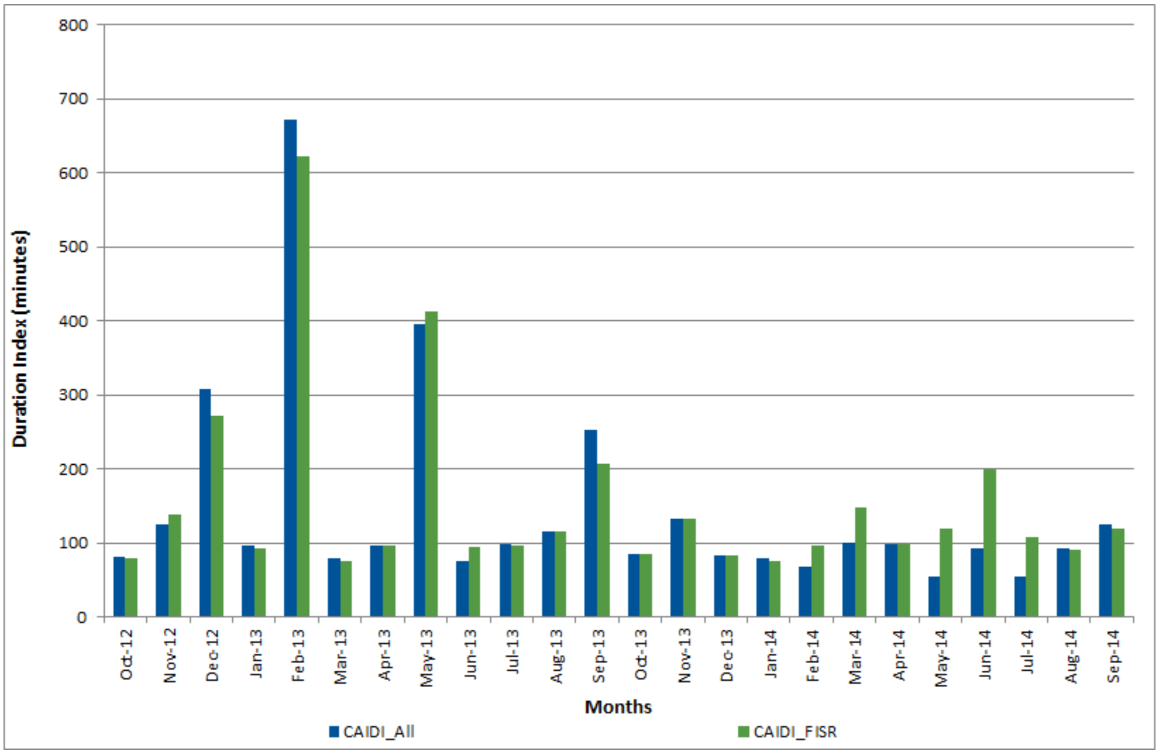


Figure 3-72: Monthly CAIDI Before and After FISR Reduced Outages



3.4.3.1.2.5 Issues and Corrective Actions

The following issues and corrective action were encountered during the performance of the Fault Isolation and Service Restoration operational demonstration and analysis.

Table 3-54: Issues and Corrective Actions

Issue	Corrective Action
• Application had real-time data sync issues.	• The application was run in a lab environment and base-setting issues were identified and changed.
• Application work flow not clearly defined.	• Application was thoroughly tested in collaboration with the vendor, and the appropriate work flow for the latest build was identified.
• Operator reluctance to put devices in remote.	• A one-time, real-world demonstration with real-world faults and no simulations was proposed and executed.
• Impact of reclosing on fuse-saving efforts for temporary faults (accurate data not available).	• A very conservative value of 33% was used for analysis. Typically, fuse saving from reclosing ranges 50%-70% range or higher for temporary faults.
• Communication infrastructure for reclosers was shaky.	• A power supply issue was identified during the operational period, an issue rectified by installing higher voltage power supplies.

3.4.3.1.3 Findings

The results obtained in the execution and analyses of the Fault Isolation and Service Restoration operational demonstration are summarized in the sections below.

3.4.3.1.3.1 Discussion

The FISR application and associated SmartGrid infrastructure were thoroughly tested and the functionality demonstrated in a real-world demonstration. Upon validation of the application and its functionality, the historical outage data of the SmartGrid feeders for the operational period was analyzed to identify the benefits from a FISR implementation.

A FISR implementation substantially reduces the operational costs and time associated with operation of typical manual distribution switches. The application also intelligently uses the available assets — relays, automated switches, FCIs — and determines switching solutions that could drastically reduce outage time and restoration time, and devote the time of field crews to fixing the actual faulty equipment.

The FISR application, as a result of its assets presence on the backbone, shall have a direct impact on all faults on the backbone of the feeder, and on transient faults on feeder laterals. With FISR, all cable faults could be momentary, with immediate location and restoration. Similarly overhead backbone faults will also be immediately located, isolated, and remaining feeder restored. Backbone faults are less frequent but have a large impact on the indices, as entire feeders are out for substantial periods. A fully automated FISR will restore cable faults in moments, reduce the number of customers affected, cut outage times on backbone faults, and eliminate operational costs for operating manual switches. With FISR, the time spent by the crew in reducing feeder outages during the operational period could have been reduced by 309.2 minutes.

Transient faults on laterals will generally blow fuses and create a prolonged outage that is then restored when a field crew replaces the fuse. Reclosing can be employed and has been used traditionally for fuse saving with feeder breakers but avoided as a result of momentary outages for entire feeders and their impact on power quality. The KCP&L implementation uses mid-circuit reclosers with single-phase reclosing that will greatly limit the number of customers affected by a momentary loss of service in case of a transient fault. This fuse-saving system will improve the indices but also substantially decrease the number of truck rolls. Backbone faults still require a field crew to roll out to fix the faulty section, but fuse-saving efforts eliminate the outage altogether, thereby eliminating the need for a field crew to roll out. Fuse Savings efforts if implemented over the operational period would have prevented 77 Truck Rolls.

Here are the benefits of FISR:

- The FISR application implementation will reduce outage times by rectifying outages quickly and preventing certain outages.
- FISR will reduce operational and restoration costs by reducing the need for truck rolls for operation and fault restoration.
- FISR, in study mode and open loop mode, can be used for system studies and planning future switching and outage events.

As a result of the above benefits the overall SAIDI and SAIFI of the SmartGrid area would have improved:

- SAIFI declined from 3.253 to 1.581.
- SAIDI declined from 403.334 to 262.137 minutes
- CAIDI increased from 123.968 to 165.782 minutes.

It must be noted that even though FISR has substantial advantages, it is a major change in operational culture and requires organizational change and slow integration into existing operations through open loop, study mode, and field demonstrations.

In future SmartGrid scenarios, FISR can be used as the application running from a centralized location or from a distributed location (substation) for providing the operator with pro-active switching suggestions as faults /outages occur and subsequently evolve through several stages into a fully automatic application that handles faults/outages and related abnormal system conditions without requiring user intervention.

3.4.3.1.3.2 Expectations vs. Actuals

The following table provides a comparison of the Expected Results and the Actual Outcomes for the Fault Isolation and Service Restoration operational demonstration.

Table 3-55: Expected Results vs. Actual Outcome

Expected Results	Actual Outcome
• Reliability will improve, resulting in significant reductions in SAIFI and SAIDI. It is estimated that SAIFI could be reduced by 20%, and SAIDI by 30%.	• The implementation of FISR would affect the following changes on the indices: • SAIFI reduced by 51%, from 3.253 to 1.581. • SAIDI reduced by 35%, from 403.334 to 262.137 min. • CAIDI increased by 34%, from 123.968 to 165.782 min.
• Operational costs will be reduced as manual switching will be executed remotely and fault locations will reduce time spent searching for faults. It is estimated that manual switching could be decreased by three (3) to six (6) truck rolls, per circuit, per year.	• Backbone faults: Only reduced labor costs were saved, as field crews were still deployed for restoration activities. • 309 minutes of labor saved. • Transient Faults: Substantial truck rolls were saved as a result of preventing fuse blowouts. • 77 truck rolls saved, or seven (7) per circuit. • 77 fuses saved.

3.4.3.1.3.3 Computational Tool Factors

The following table lists the values derived from the Fault Isolation and Service Restoration operational demonstration that will be used as inputs to the Smart Grid Computational Tool.

Table 3-56: Computational Tool Values

Name	Description	Calculated Value
SAIDI	System Average Interruption Duration Index	3.025 Hrs. – Baseline 1.966 Hrs. – Project
Truck Rolls	Avoided operations truck rolls for outage restoration.	77
Restoration Labor Saved (Hr)	Restoration labor saved due to reduced troubleshooting	5.15 hours (309 minutes)
Other Reduced T&D Operations Cost ($)	Functions that provide this benefit help restore power quicker and with less manual labor hours which result in lower restoration costs	$ 901.25
Reduced Restoration Cost ($)	Functions that provide this benefit lead to fewer outages thus reducing the number of outage events that must be responded to.	$ 20,020

- SAIDI (Baseline): This value is calculated as the 3 year average of the reported project level Impact Metrics values.

- SAIDI (Project): This value is calculated as the SAIDI Baseline adjusted by the 35% improvement identified in this demonstration analysis.

- Reduced Other T&D Operations Cost ($) –this value is calculated as follows:

  Restoration Labor Saved (Hr) x Cost of Restoration Crew Labor ($/Hr)

  5.15 Hr x $175/Hr = $901.25

- Reduced Restoration Cost T ($) –this value is calculated as follows:

  Avoided Restoration Truck Rolls (event) x Average Cost of Restoration Truck Roll ($/event)

  77 events x $260/event = $20,020

3.4.3.1.4 Lessons Learned

Throughout the conduct of the operational testing and analysis of the Fault Isolation and Service Restoration function, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- Change Management for Automated Switching/Operator Readiness: Highly automated switching in a manual switching environment is generally met with apprehension. The application must have functionality to monitor, and then partially enable, automation with the ability to revert back to normal in a phase-by-phase manner. Additional flexibility with areas and operator friendly functionality would ease the transition.
- Open Loop and Closed Loop Functionality: Both the open loop and closed loop modes provide substantial improvements when compared to a system with manual switching and without mid-circuit reclosers. The open loop functionality was successfully used for the demonstration of the application and was instrumental in getting the operation team to work for a demonstration. The highly automated closed loop mode is an improvement on open loop, but FISR implementation in only open loop (suggestion) mode can also be pursued.
- Situational Awareness: The operator currently could use FISR in a single outage/calm day scenario but would not use it on a busy/major outage/storm scenario. There can be great improvement in UI efficiency in integrating the apps and their solutions into the UI to improve situational awareness and enable the operator to use that suggestion.
- Mid-circuit Reclosing: Fuse-saving techniques using mid-circuit reclosers with single phase reclosing eliminate the disadvantages associated with traditional fuse-saving techniques that use feeder head breakers.
- Study Case: A fully functional study case mode is crucial for improving operator readiness for implementing FISR. The study case will also assist in planning for future outages in coordination with open loop mode. The study case mode can also be used to test the application and must be accorded high priority during build and implementation for automated apps in a manual operating culture.
- Infrastructure Reliability: The FISR application, with all its advanced computation and real-time analysis, is extremely dependent on infrastructure availability. The availability of communication infrastructure, reliable protection settings, and other systems is crucial for FISR implementation. High reliability is critical; any minor shortcoming or problems with the infrastructure elements typically casts a shadow on the actual application and erodes end user satisfaction.

3.4.4 Automated Islanding and Reconnection

Automated islanding and reconnection is achieved by automated separation and subsequent reconnection (autonomous synchronization) of an independently operated portion of the T&D system (i.e., microgrid) from the interconnected electric grid. A microgrid is an integrated energy system consisting of interconnected loads and distributed energy resources which, as an integrated system, can operate in parallel with the grid or as an island.

3.4.4.1 Feeder Islanding with Grid Battery

Feeder Islanding with Grid Battery is a demonstration of one aspect of the Automated Islanding and Reconnection function.

3.4.4.1.1 Overview

The following sections provide an overview of the operational, demonstration, testing, and evaluation methodology used for the Feeder Islanding with Grid Battery operational demonstration.

3.4.4.1.1.1 Description

A .0-MW/1.0-MWh-capable grid-connected Battery Energy Storage System has been installed adjacent to the Midtown Substation with direct interconnect to a single 13.2-kV circuit. DMS-based battery control functions were implemented to allow the distribution grid operator to put the BESS in Islanding mode and discharge the battery while a portion of the circuit was disconnected from the grid. Once the BESS was placed in Islanding mode, it maintained power to the isolated section until grid power was restored or the battery was fully discharged.

3.4.4.1.1.2 Expected Results

The technical demonstration of the grid connected battery in this application was expected to yield the following:

- During a scheduled, controlled outage to the circuit, demonstrate that the BESS could restore power to customers after a brief outage.
- When grid power was restored, the BESS would automatically synchronize to the grid and seamlessly connect back to grid power without a second outage.

3.4.4.1.1.3 Benefit Analysis Method/Factors

The Technical Demonstration of the use of the BESS in this application did not contribute to the project Benefits Analysis.

3.4.4.1.1.4 Demonstration Methodology

The following points provide an overview of how the technical demonstration of this application was accomplished:

- KCP&L will arrange a scheduled outage, for all customers on the feeder serving the BESS, at a time that will have minimal customer impact.
- The Grid Operator opened the feeder breaker, creating a feeder outage.
- The Grid Operator opened the source-side recloser, leaving the BESS to activate in Islanding mode, restoring power to customers downstream from the recloser.
- The BESS was allowed to sustain power to customers for a period of time.
- The Grid Operator closed the feeder breaker, restoring power to the source side of the recloser.

- The BESS performed a sync check and adjusted BESS power output to synchronize the islanded section to the grid.
- Once the islanded section was in-sync with the grid, the BESS closed the recloser and discontinued discharge.

3.4.4.1.1.5 Analytical Methodology

The Technical Demonstration of this application does not require any analytical calculations.

3.4.4.1.2 Plan Execution and Analysis

The following sections provide details regarding the functional tests,, data collection, and analysis performed for the Feeder Islanding with Grid Battery operational demonstration.

3.4.4.1.2.1 Configuration and Settings

Figure 3-73 below is a one-line diagram of feeder 7564 connected to the 1.0-MWh BESS, and customer loads. The load on this feeder is fed from the feeder breaker 7564, at Midtown Substation. In an event where the fault is at the feeder breaker, the load can be alternatively fed by feeder breaker 7554 by closing the switch. The feeder 7564 supplies power to a mix of commercial and residential customers. The peak summer load noted for this feeder is about 1,500 kW. The average load for the feeder is 850 kW in the summer and about 700 kW for rest of the year. Based on the low load demand and the radial connection, the project team determined that this feeder was a good candidate for testing the BESS islanding capabilities.

Figure 3-73: One-Line Diagram for Circuit 7564

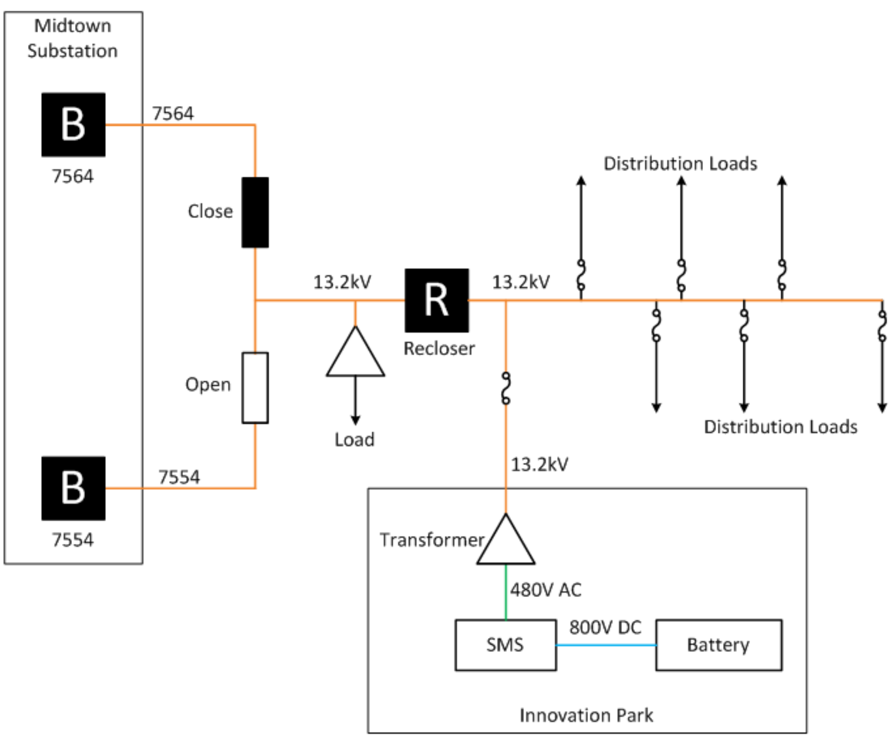
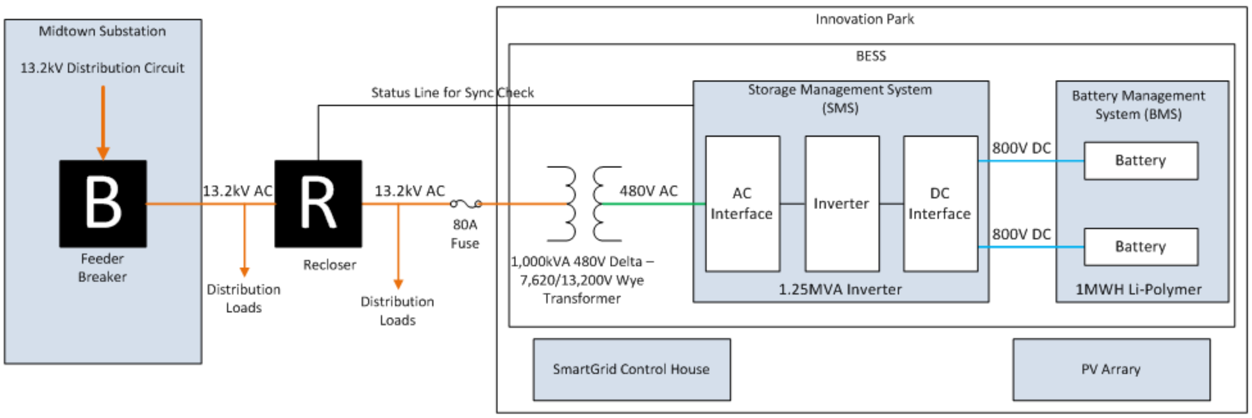


Figure 3-74 below is the one-line diagram of the grid-connected BESS. The battery is connected to the Storage Management System (SMS) through an 800-V DC line. The SMS consists of the DC interface, inverter, and AC interface. The AC interface consists of a Power Conversion System (PCS) and a Real-Time Automation Controller (RTAC). The inverter in the SMS converts 800-V DC to 480-V AC. The SMS also has a Current Transformer (CT) and a Potential Transformer (PT) to record power output and voltage of the PCS and battery combined. The SMS is connected to the utility circuit through a 1,000-kVA Delta-Wye transformer. The transformer steps up the 480-V AC output from SMS to 13.2-kV that is connected to the recloser. In case of an outage event the recloser provides grid isolation. The recloser is separately connected to the SMS for sync-check function. The sync-check function checks voltage levels on both side of recloser — voltage from the utility grid as well as battery. The battery will increase or reduce the voltage to be equal to the utility voltage, after the fault is cleared to close the recloser. Downstream of recloser is the customer load, which can be isolated and power can be supplied by the BESS.

Figure 3-74: One-Line Diagram of Grid-Connected Battery



For the islanding demonstration, the following settings were configured in the SMS:

- The battery was set to discharge in Voltage Source (VS) mode.
- The PCS Ramp Rate was set to 20 kW/sec. With this setting it took 10 seconds to ramp up charge, or ramp up discharge, to the output power of 200 kW.

3.4.4.1.2.2 Circuit Islanding Functionality Demonstration

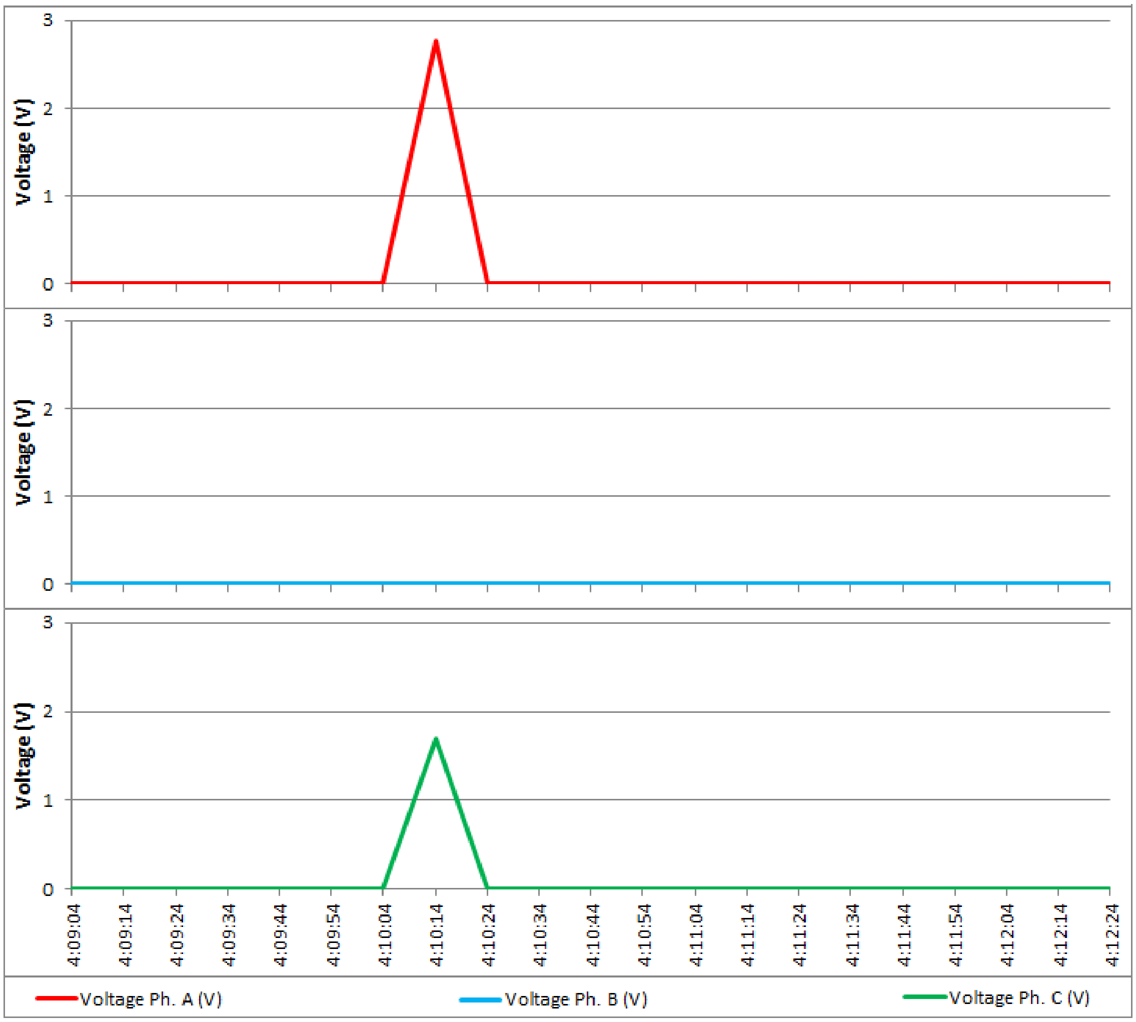
As a part of SGDP, the islanding functionality was demonstrated in real time in the field. This functionality was not implemented in a regular basis as it required manual operation and changes in the metering points for islanding from 480-V line to 13.2-kV line. In Islanding mode, BESS operates as a voltage source and runs at the set AC voltage supplying the power and VARs required by connected loads.

The demonstration was planned to mimic a real-world outage scenario. Customers in the feeder were notified a day ahead regarding the planned outage, which would be for one hour to demonstrate circuit islanding. The team selected the time that would have minimal impact on customers. The SmartGrid and operations teams worked closely during the demonstration.

A fault between a feeder breaker and a recloser in a real-world case would open both the breaker and recloser. This was simulated by opening breaker in the Midtown Substation, and then the recloser in the field though the OMS. This resulted in loss of power to all 83 customers downstream of the breaker.

The operator put the BESS in (VS) mode from SMS HMI to restore the power to customers downstream of recloser from the BESS. The BESS attempted to discharge in VS mode but the internal SMS alarms for the inverter received in SMS prevented the battery from discharging. Figure 3-75 shows that the BESS attempted to discharge for few seconds until the alarm stopped the BESS from discharging.

Figure 3-75: First Attempt for Islanding Demonstration 3-Phase Voltage in the SMS



To provide power to customers, the recloser and breaker were closed while the operator worked to resolve the issue. The operator was able to determine the cause of the alarm and resolve it. The team again attempted to feed the islanded circuit. After the outage was simulated, the BESS was set to discharge in VS mode again. The BESS attempted to discharge but the internal SMS alarm for chopper/DC interface received in SMS prevented BESS from discharging. While the operator was able to clear the alarm and resolve the issue, the process took more than one hour, which had been outage duration that had been sent as a notification to customers.

To demonstrate the islanding functionality, the team decided to reconfigure the circuit to isolate the Innovation Park so that the BESS could power the load at Innovation Park.

3.4.4.1.2.3 Innovation Park Islanding Functionality Demonstration

In order to demonstrate the islanding functionality of the BESS, the circuit was configured so that Innovation Park was isolated from rest of the feeder. The customers had power at all times during Innovation Park islanding demonstration. The fuse close to the recloser was opened to isolate Innovation Park from rest of the feeder. Innovation Park's loads include the control house and auxiliary loads such as lights, HVAC, etc., in both the SMS and battery enclosures.

After the issues were resolved the operator put the BESS in VS mode from SMS HMI. The BESS started to discharge, to support the loads. Figure 3-76 below shows the 10-second interval power output of the BESS, as captured in SMS. The BESS supplied the load for about 20 minutes without any other issues.

Figure 3-76: Battery and SMS Load Graph During Islanding

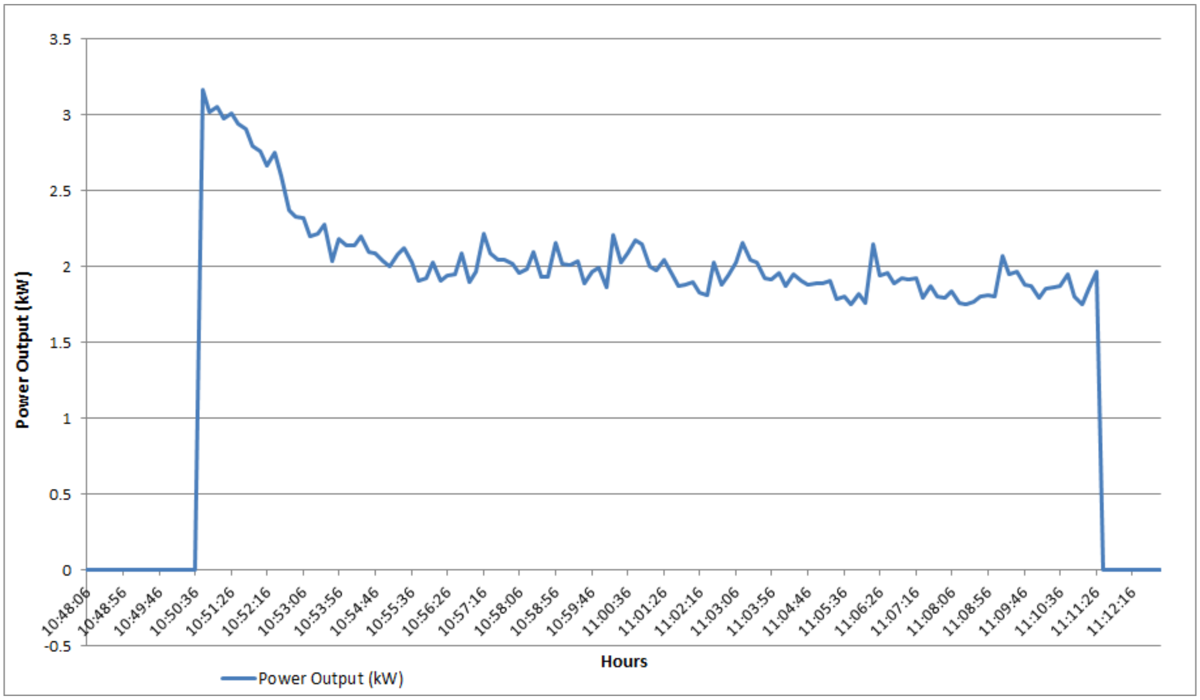


Figure 3-77 below shows the SMS ramping up the voltage as the BESS began discharging. The Phase A voltage is shown in red; Phase B voltage is shown in green; and Phase C voltage is shown in blue. The fluctuation on the voltage as it ramps up is due to no or low load at initial startup. But when the voltage reached its nominal voltage, the waveform became much smoother. It took about 0.45 seconds, or 27 cycles, to reach the nominal voltage of 13.2 kV.

Figure 3-77: Battery (SMS) Voltage During Islanding

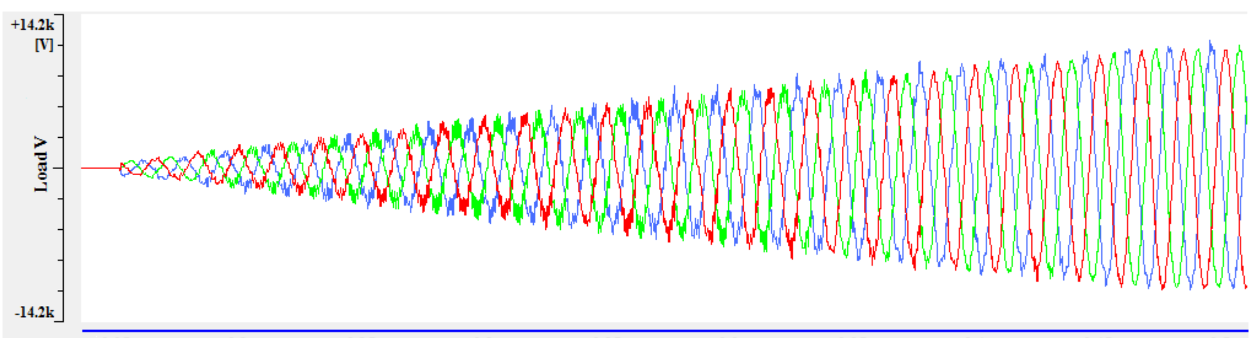
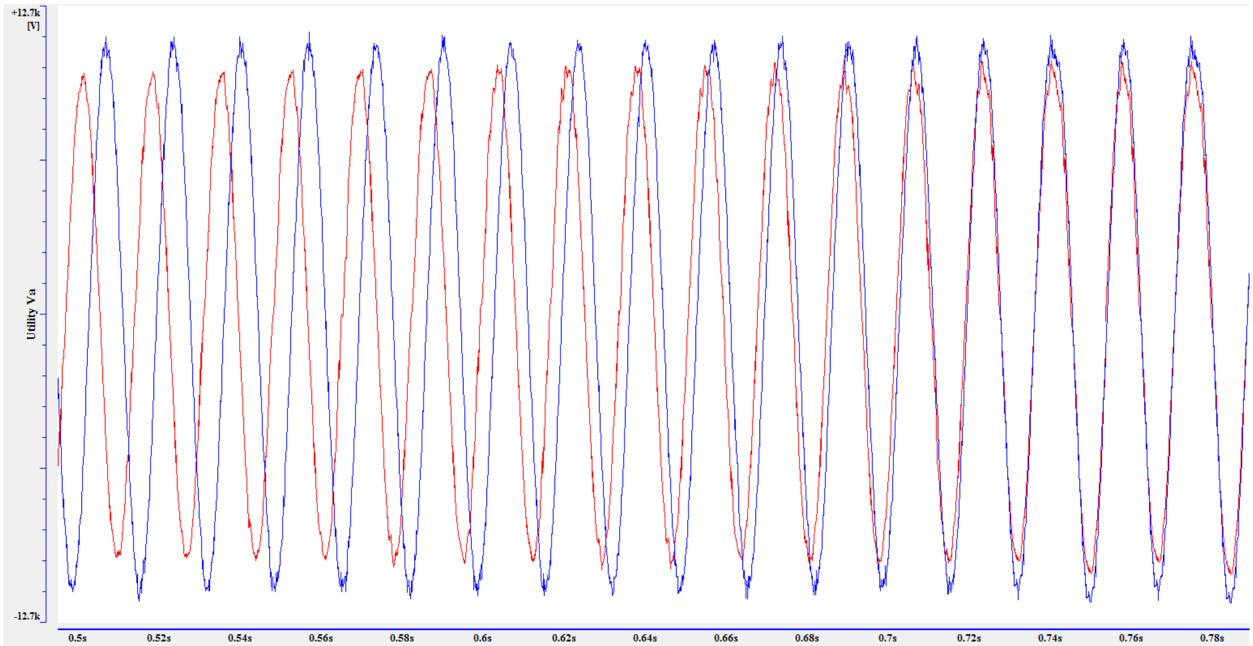


Figure 3-78 shows the SMS AC voltage synchronizing with the utility voltage. The waveform in red is Phase A voltage of the SMS, and the one in blue is Phase A voltage of the utility. The PT ratios in SMS and utility are different, resulting in different magnitude of voltage. The SMS voltage waveform was 90° off phase from the utility voltage and took 0.25 seconds, or 15 cycles, to synchronize with the utility voltage.

Figure 3-78: Grid and Battery Voltage Synchronized



3.4.4.1.2.4 Issues and Corrective Actions

The following issues and corrective action were encountered during the performance of the Feeder Islanding with Grid Battery operational demonstration and analysis.

Table 3-57: Issues and Corrective Actions

Issue	Corrective Action
• Voltage dividers could not support the load.	• Brought secondary voltage from adjacent transformer to monitor recloser high-side voltage.
• SMS missing inputs for primary voltage – needs external points for synchronization.	• Because of delta-Y had to switch SMS from internal 480 V to metering PTs.
• Alarms in SMS prevented BESS from discharging.	• Alarms were changed from “alarm” to “warning” to allow the BESS to discharge.

3.4.4.1.3 Findings

The results obtained in the execution and analysis of the Feeder Islanding with Grid Battery operational demonstration are summarized in the sections below.

3.4.4.1.3.1 Discussion

The islanding functionality was conducted to demonstrate the capability of a 1.0-MW/1.0-MWh battery to discharge in VS mode. Even though the BESS was not able to discharge to supply the load in the entire feeder, the BESS was able to support a small load within Innovation Park to demonstrate the ability of battery to discharge in VS mode.

The SMS voltage was able reach the nominal voltage level in about 27 cycles, and sync with the utility voltage in 15 cycles. This shows that the BESS is able synchronize with utility voltage automatically and support the load instantly.

3.4.4.1.3.2 Expectations vs. Actuals

The following table provides a comparison of the Expected Results and the Actual Outcomes for the Feeder Islanding with Grid Battery operational demonstration.

Table 3-58: Expected Results vs. Actual Outcome

Expected Results	Actual Outcome
• A scheduled, controlled outage to the circuit would demonstrate that the BESS could restore power to customers after a brief outage.	• During a brief outage, the BESS was able to restore power to the load.
• Upon restoration of grid power, the BESS would automatically synchronize to the grid and seamlessly connect back to grid power without a second outage.	• The BESS automatically synchronized with the grid voltage and instantly supported the load.

3.4.4.1.3.3 Computational Tool Factors

This demonstration did not produce any inputs to the Smart Grid Computational Tool benefits analysis.

3.4.4.1.4 Lessons Learned

Throughout the conduct of the operational testing and analysis of the Feeder Islanding with Grid Battery function, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- Putting the BESS in VS mode is a manual process. An operator must be present and needs access to multiple systems to making the proper change to VS mode. As such, the process can pose challenges during real-time outages.
- The battery was not modeled as an injection source in the OMS section of the DMS. Therefore, during islanding the customers were still considered to be out of power. In order to avoid the confusion, the battery source needs to be modeled as an injection point in DMS for better outage and restoration management.
- An auxiliary controller, Real-Time Automation Controller (RTAC) was required for islanding purposes. The RTAC collects the information from the recloser and the storage management system to determine the outage information and close the recloser after the outage has been cleared.
- A thorough check of the alarms set for inverter and chopper in the SMS should be done beforehand. Alarms set in SMS should be verified, to be sure that the SMS is set for the correct type of battery.

3.4.5 Diagnosis & Notification of Equipment Condition

Diagnosis and notification of equipment condition is defined as online monitoring and analysis of equipment, its performance, and operating environment in order to detect abnormal conditions (e.g., high number of equipment operations, temperature, or vibration). Asset managers and operations personnel can then be automatically notified to respond to conditions that increase the probability of equipment failure.

3.4.5.1 Substation Protection Automation

Substation Protection Automation is a demonstration of one aspect of the Diagnosis & Notification of Equipment Condition function.

3.4.5.1.1 Overview

The following sections provide an overview of the operational, demonstration, testing, and evaluation methodology used for the Substation Protection Automation operational demonstration.

3.4.5.1.1.1 Description

An IEC 61850-compliant substation communication controller and substation protection network was installed in the Midtown Substation, along with various other component upgrades, to enable substation protection automation. Component upgrades included replacement of electromechanical relays with intelligent electronic relays, and deployment of enhanced protection schemes. All new relays communicated directly with the substation controller. The substation protection network provided distributed intelligence at the substation to enable execution of automated protection operations based on feedback from real-time monitoring of transformers, relays, cap banks, and other field equipment.

3.4.5.1.1.2 Expected Results

The technical demonstration of the Substation Protection Automation was expected to yield the following:

- Substation Protection Automation would reduce operation and maintenance costs compared to the electromechanical relays.
- Automated actions based on real-time feedback would also help prevent component failures or route power around component failures within the substation, thus improving reliability and further reducing operation and maintenance costs.
- Implementation in accordance with IEC 61850 would provide experience and learning for the industry.
- Monitoring of all substation equipment would provide better operating data for utility decision making.

3.4.5.1.1.3 Benefit Analysis Method/Factors

This Technical Demonstration does not contribute to the project Benefits Analysis.

3.4.5.1.1.4 Demonstration Methodology

The following points provide an overview of how the technical demonstration of this application was accomplished:

- Electronic relays were deployed in Midtown substation, running in parallel with existing hardwire connections to the RTU.
- IEC61850 GOOSE protection schemes were deployed on the substation relays via CID files.
- Cross-triggering GOOSE scheme was enabled via a setting in the relay settings files.

- The relays began collecting information from the cross triggering GOOSE scheme. The relays ran in this mode for ~6 months.
- The SG team and KCP&L engineers used the event information for enhanced visibility into substation events and real-time device information.
- After gaining trust, protection schemes then were would be deployed.
- Performance of GOOSE schemes was monitored and compared to traditional hardwired protection.

3.4.5.1.1.5 Analytical Methodology

The Technical Demonstration of this application does not require any analytical calculations.

3.4.5.1.2 Plan Execution and Analysis

The following sections describe how the plan was executed, plus analysis regarding the Substation Protection Automation operational demonstration.

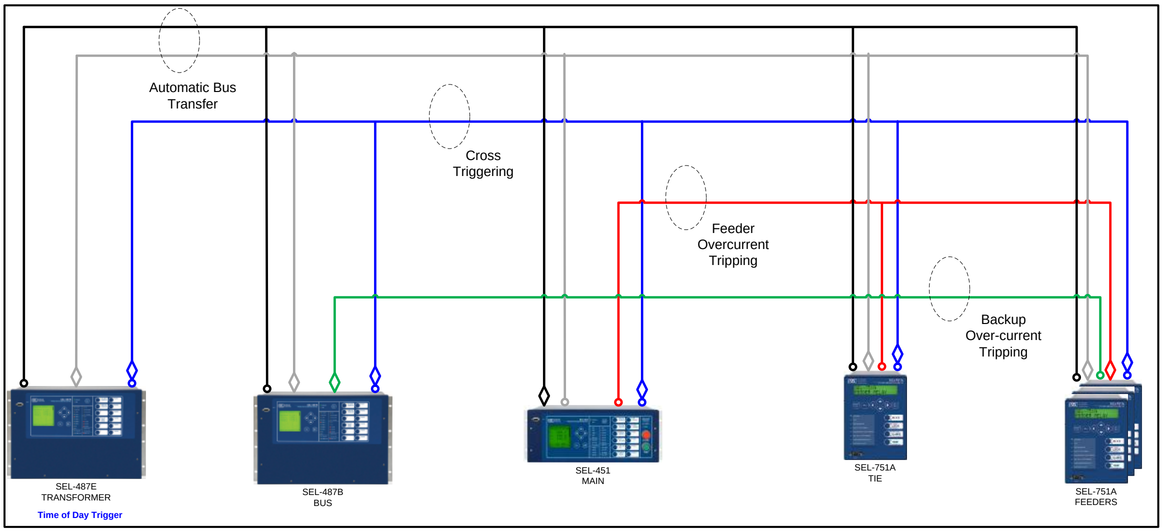
3.4.5.1.2.1 GOOSE Schemes

Four GOOSE schemes were designed for the Substation Protection Automation operational demonstration:

- Cross-triggering: Cross-triggering of all devices for every distribution system event and at a specific time each day provides the Engineering Department with detailed oscillography and event information, explaining how protection and control functions perform under fault conditions. Analyzing this information allows schemes and settings to be optimized, providing customers with more reliable service.
- Faster overcurrent tripping: This scheme accelerates overcurrent tripping of main and tie breakers upon feeder breaker failure, reducing wear on equipment, decreasing the likelihood of equipment failure, and improving customer reliability.
- Backup overcurrent tripping: Such protection in the bus differential relay provides redundancy to the logic, sensors, and wiring in the feeder relays, allowing them to trip a feeder with a reclosing function if the feeder relay failed to detect or clear a fault.
- Load transfer: This scheme would provide automatic load transfer upon transformer lockout. This scheme was not deployed.

The GOOSE logic diagram in Figure 3-79 shows which substation relays were involved in each of the GOOSE schemes.

Figure 3-79: GOOSE Logic Diagram



3.4.5.1.2.2 GOOSE Activation and Production Testing

KCP&L took an incremental approach to GOOSE activation in order to gain comfort with the automation. Although this strategy required additional trips to the Midtown relays, it allowed for "safe" testing in the production environment. There are two settings pertaining to IEC61850 that are stored in the relay settings files. The "Enable IEC 61850 Protocol" setting in the relay settings file has been enabled since the substation devices were originally deployed at Midtown – this setting allows the substation relays to communicate to the SICAM using IEC61850 MMS messages. The second setting pertaining to IEC61850 is the "Enable IEC 61850 GOOSE" setting, and this was activated in January 2014.

After the January changes, one scheme was fully functional – the cross triggering of all devices for distribution system events. The event reporting scheme was triggered any time an "event" occurred, but since this scheme is simply reporting of statuses of all the substation devices, no devices opened or closed as a result. The other GOOSE schemes were put in monitor-only mode at this point. To do this, KCP&L took the settings that were already deployed in the relays, and they made modifications necessary to complete the GOOSE logic except for the trip and close equations. With these changes, when an event occurred, the relays did everything they were supposed to up until the point where a relay trip or close should occur.

While in monitor-only mode, a number of events occurred on Midtown feeders. For each event, KCP&L conducted a post-event analysis to determine whether the GOOSE logic would have resulted in the correct action. During monitor-mode operations, a number of issues arose – these are described in Section 2.2.3.4.3. None of the post-operational issues required any changes to the logic schemes, however.

After several months of monitor-only mode, the relay settings were updated again to put the devices in full operation mode for two additional schemes: 1) backup overcurrent protection in the bus differential relay, and 2) faster clearing of the bus upon feeder breaker failure schemes. To change to full operation mode, KCP&L took the trip and close equation and added in one more element that is controlled by GOOSE logic. These changes were only deployed to the relays on buses 7 and 8. The automatic load transfer upon transformer lockout scheme was not put into full operation mode, as KCP&L determined that it would require significant outages to conduct a full-fledged test.

One fault has occurred on a bus 8 feeder since switching to full operation mode, but unfortunately the GOOSE logic did not operate due to some communications issues. KCP&L will continue to run buses 7 and 8 in full operation mode and do post-event analysis to verify that the GOOSE schemes function properly in the future.

Below is a 2014 list of substation lockout events and when each occurred.

Table 3-59: Substation Events and Dates/Times

Feeder	Lockout Type	Date and Time
7570	86B Lockout Operated	01/15/2014 21:28:40
7580	86B Lockout Operated	01/15/2014 21:28:40
7541	Feeder Lockout Operated	01/18/2014 20:35:21
7541	Feeder Lockout Operated	01/19/2014 02:43:22
7541	Feeder Lockout Operated	01/19/2014 09:37:35
7520	86B Lockout Operated	01/27/2014 13:04:49
7520	86B Lockout Operated	04/17/2014 15:51:46
7570	86B Lockout Operated	01/31/2014 11:02:46
7580	86B Lockout Operated	01/31/2014 11:05:15
7581	Feeder Lockout Operated	02/03/2014 13:25:37
7581	Feeder Lockout Operated	02/03/2014 14:46:47
7573	Feeder Lockout Operated	03/11/2014 20:44:59
7573	High Current Lockout	03/11/2014 20:44:59
7573	Feeder Lockout Operated	03/12/2014 11:32:53
7531	Feeder Lockout Operated	03/17/2014 07:49:20
7510	86B Lockout Operated	04/17/2014 15:51:46
7520	86B Lockout Operated	04/17/2014 15:51:46
7563	Feeder Lockout Operated	05/27/2014 15:58:25
7581	Feeder Lockout Operated	05/28/2014 20:24:11
7581	Feeder Lockout Operated	06/11/2014 15:29:57
7581	Feeder Lockout Operated	06/11/2014 16:24:22
7571	Feeder Lockout Operated	06/30/2014 22:00:12
7543	Feeder Lockout Operated	06/30/2014 23:22:27
7543	Feeder Lockout Operated	06/30/2014 23:24:49
7543	Feeder Lockout Operated	06/30/2014 23:25:15
7582	Feeder Lockout Operated	07/01/2014 13:45:06
7582	High Current Lockout	07/01/2014 13:45:06
7541	Feeder Lockout Operated	07/02/2014 11:31:47
7572	Feeder Lockout Operated	07/07/2014 22:27:13
7582	Feeder Lockout Operated	07/08/2014 15:05:06
7581	Feeder Lockout Operated	07/22/2014 18:55:41
7581	Feeder Lockout Operated	07/24/2014 15:21:20
7553	Feeder Lockout Operated	08/26/2014 18:02:13
7570	86B Lockout Operated	09/15/2014 17:08:32
7570	86B Lockout Operated	09/15/2014 20:08:18

3.4.5.1.2.3 Event Performance with GOOSE Protection Schemes

Upon completion of an event at Midtown that yields GOOSE operation, KCP&L will analyze the performance. Ultimately, the objective is to compare the performance of the GOOSE schemes to the traditional hard wired performance.

3.4.5.1.2.4 Issues and Corrective Actions

The following issues and corrective action were encountered during the performance of the Substation Protection Automation operational demonstration and analysis.

Table 3-60: Issues and Corrective Actions

Issue	Corrective Action
• 61850 CID file management exposed complications between versions.	• Worked with protection and control engineers and relay technicians to implement many manual processes to keep track of versioning.
• Communications issues with protection and control network prevented analysis an event because logs were filled up. A separate event didn't function using the GOOSE logic because the communications didn't get from one device to another.	• Performed troubleshooting of network and issue resolution to ensure that communications are as robust as possible so that the GOOSE schemes function properly.
• Upon analysis of the first set of events at Midtown substation, KCP&L discovered that not all devices were storing the same current time.	• KCP&L investigated the time synchronization issues and discovered that there were several causes. Some devices required the DST settings to be adjusted. Other devices required a change to the UTC offset. Finally, several devices required a change to a particular dipswitch in the SEL relays.

3.4.5.1.3 Findings

The results obtained in the execution and analyses of the Substation Protection Automation operational demonstration are summarized in the sections below.

3.4.5.1.3.1 Discussion

Using the cross triggering GOOSE scheme has provided utility engineers with detailed, reliable data that can be used to determine what maintenance, replacements and associated upgrades will need to be made, and when. Collecting data about how many times a breaker is opened and closed, for example, creates a baseline of information that can be used now and in the future to make effective decisions connected to its use: When should it be inspected? How should it be maintained? How much money should be budgeted for eventual replacement? What additional circuits will need to be added? Such questions can be forecast now, and executed with increasing confidence as detailed data is compiled throughout the system.

Deploying the other GOOSE schemes has given KCP&L insight and experience to the typical issues that arise when a network of this type is deployed in a substation. Through the involvement of various vendors and departments at KCP&L, several post operational issues have been resolved.

3.4.5.1.3.2 Expectations vs. Actuals

The following table provides a comparison of the Expected Results and the Actual Outcomes for the Substation Protection Automation operational demonstration.

Table 3-61: Expected Results vs. Actual Outcome

Expected Results	Actual Outcome
• Substation Protection Automation will reduce operation and maintenance costs compared to the electromechanical relays.	• Using the cross triggering GOOSE scheme provided utility engineers with detailed, reliable data that can be used to determine what maintenance, replacements and associated upgrades will need to be made, and when.
• Automated actions based on real-time feedback will also help prevent component failures or route power around component failures within the substation, thus improving reliability and further reducing operation and maintenance costs.	• GOOSE protection schemes are in place and ready to be used when events occur in Midtown substation.
• Implementation in accordance with IEC 61850 will provide experience and learning for the industry.	• The project provided experience and learning for the industry regarding IEC 61850. KCP&L has been an active participant in a variety of industry conferences and other events. For a complete list, see Industry Conferences, Section 3.3.5.4. Also, see an article, "Wired for Success," from Transmission & Distribution World, in Appendix P.5.1.23. For other articles, see Industry Publications, Section 3.3.5.3. Project representatives and employees from KCP&L intend to continue sharing their knowledge, and picking up more knowledge themselves, well into the future.
• Monitoring of all substation equipment will provide better operating data for utility decision making.	• Monitoring provided utility engineers with better data, which helped improve their understanding of when events occurred in the substation and which devices were impacted. Engineers also received detailed, reliable data on operations - data that can be used to better project maintenance, replacements, and other upgrades.

3.4.5.1.3.3 Computational Tool Factors

This demonstration did not produce any inputs to the Smart Grid Computational Tool benefits analysis.

3.4.5.1.4 Lessons Learned

Throughout the demonstration of the Substation Protection Automation function, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- CID and relay settings file management can be difficult in an IEC 61850 network. For this project, KCP&L worked with protection and control engineers and relay technicians to implement many manual processes to keep track of versioning. For future implementations, however, KCP&L would likely utilize some sort of automated process or system to perform the file management tasks.
- Deadbands played an important role in the GOOSE deployment. For the transfer scheme, the logic is designed to send analogs. KCP&L had to double check all the multipliers and deadbands to ensure that the devices weren't sending GOOSE updates too frequently.
- Vendor interoperability of the IEC 61850 standard can be problematic. KCP&L used all SEL relays, so this wasn't a big problem for the demonstration implementation, but it became obvious throughout the design/testing/build of the GOOSE component that things would have been much more complex had KCP&L utilized relays from multiple vendors. Taking advantage of the flexibility in the IEC 61850 standard, vendors have implemented the GOOSE protocol somewhat differently. For example, the standard specifies four identifying characteristics for each GOOSE message. Certain vendors will only use two of these characteristics for identification, while other vendors might use three characteristics, which may or may not overlap. Moving forward, utilities need to push the vendors to standardize on their GOOSE implementations.
- KCP&L's deployment of the GOOSE schemes was slow and cautious. Any time a utility moves to a new technology, there will be resistance to change, especially if the current technology seems to be working smoothly.
- Although the cross triggering scheme doesn't result in any actions taken by substation relays, it has proven to be very beneficial for KCP&L engineers. They are able to see the status of all substation devices any time an event occurs in the substation, and this is very useful for post-event analysis.
- Since KCP&L has experienced several issues with communications in the Midtown protection and control LAN, the engineers have given lots of thought to how communications issues impact the GOOSE schemes. For the faster clearing of the bus upon feeder breaker failure scheme, if communications fail and the devices operate based on their local protection settings, the result is no worse than the pre-GOOSE scheme. For the backup overcurrent protection of the bus differential relay scheme, however, if the communications fail, the result could be worse than the pre-GOOSE condition. If the feeder operates before the bus differential, then it isn't an issue. If the bus differential operates first and communications are down, however, then no reclosing will occur. Understanding the impact of communications failures on the outcome of various substation events with and without the GOOSE schemes is beneficial. If KCP&L re-designed the GOOSE schemes today, they would likely modify the logic so that if communications went down, the devices would just revert back to the old way of doing the scheme.

3.4.5.2 Asset Condition Monitoring

Asset Condition Monitoring is a demonstration of one aspect of the Diagnosis & Notification of Equipment Condition function.

3.4.5.2.1 Overview

The following sections provide an overview of the operational, demonstration, testing, and evaluation methodology used for the Asset Condition Monitoring operational demonstration.

3.4.5.2.1.1 Description

An asset condition monitoring and reporting infrastructure was installed for all key substation and field devices throughout the SGDP area. The asset condition monitoring and reporting infrastructure that was implemented includes enhanced equipment, sensors and control capabilities, real-time condition monitoring and alarming capabilities in the DMS, and the HIS for archival of reported conditions for later analysis.

3.4.5.2.1.2 Expected Results

The technical demonstration of the Asset Condition Monitoring was expected to yield the following:

- Analysis of condition monitoring data from currently available industry equipment controls would provide experience and learning for the industry.
- Implementation of report-by-exception condition monitoring data from current industry equipment controls would provide experience and learning for the industry.
- Demonstrate how remote asset condition data could be collected that with further analysis could reduce operation and maintenance costs, as conditions would be determined remotely in real time.
- Record any actions based on real-time feedback that were used to help identify and/or prevent component failures, thus improving reliability and further reducing operation and maintenance costs.

3.4.5.2.1.3 Benefit Analysis Method/Factors

The DOE SGCT was used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits were quantified.

- Reduced Equipment Failures
- Reduced T&D Equipment Maintenance Cost

Benefits were calculated using SGCT formulas. The following factors were measured, projected or calculated during the application operation and/or demonstration.

Reduced Equipment Failures

- Capital Replacement of Failed Equipment ($)

Reduced T&D Equipment Maintenance Cost

- Reduced Distribution Equipment Maintenance Cost ($)

3.4.5.2.1.4 Demonstration Methodology

The following points provide an overview of how the technical demonstration of this application was accomplished:

- A fiber substation protection network was deployed at Midtown substation to enable communications to substation devices, and a Tropos wireless mesh network was deployed throughout the SGDP area to enable communications to field devices.
- A detailed point analysis was conducted for each substation and field device type to determine which points are useful for operational data and which points are useful for asset condition monitoring. The number of data points monitored went from 5-10 points per device previously to 50-100 points per device for the SGDP. See Appendix F for a list of all points for each device type.
- Intelligent Electronic Devices (IEDs) were deployed in Midtown substation and along the 11 designated smart grid feeders extending from Midtown substation. These devices were configured to report by exception rather than use traditional SCADA polling.
- Data from the substation IEDs was displayed on the HMI.
- Data from the substation and field IEDs was reported to a substation data concentrator.
- All data from the data concentrator was sent to the central DMS/HIS or substation DCADA/HMI for monitoring purposes.
- The DMS or DCADA utilized the substation and field device data as inputs for First Responder applications, and sent control commands back out to the devices.
- The HIS was used to store asset data over time.

3.4.5.2.1.5 Analytical Methodology

The following points provide an overview of the analytical methods that was used to evaluate the impact and benefits of this application:

- The avoided Capital Replacement of Failed Equipment cost for the SGDP was determined based on the actual equipment failures avoided based on improved asset condition monitoring.

3.4.5.2.2 Plan Execution and Analysis

The following sections describe how the plan was executed, plus analysis regarding the Asset Condition Monitoring operational demonstration.

3.4.5.2.2.1 Points Analysis for Asset Management

As KCP&L began to develop the points list for all of the substation and field devices, careful attention was given to the various uses for data. In the past, the points list was composed of information that was for purely operational use – SCADA data. For this project, however, KCP&L sought to bring back data that would be beneficial for enhanced asset management as well as advanced applications.

As a result of these expanded objectives, the quantity of desired data points increased immensely. KCP&L previously monitored 5-10 points per device, but for the SGDP, 50-100 points were monitored per device.

Refer to Appendix F for a complete listing of all points for each device type. Refer to Section 2.2.3.2 for more specific discussion about the points list development.

3.4.5.2.2.2 Operator Data Presentment

Because various utility personnel use the substation and field device data for different purposes, KCP&L thoughtfully determined the data that was relevant to each user type and included that information in the relevant user interface. For example, relay technicians, engineers, and distribution system operators all require different sets of data. Relay technicians need access to the most critical data – device open/close, alarms, and a few important status points. Distribution system operators and engineers need access to a larger set of device data for troubleshooting and planning purposes.

As a result of these differing data needs, different presentations of a particular device's data were logical. Consider a feeder breaker, R7553, for example. Figure 3-80 below shows the HMI's presentment of this device. The HMI is the user interface that the relay technicians would utilize while in the substation. This feeder is shown on a screen with the other feeders on bus 5, and it includes only the most critical information about that feeder. The same device is shown again in Figure 3-81, but this time R7533 is shown through the DMS presentment. The DMS shows many more data points about this feeder breaker. This information would be useful to the distribution system operators or the engineers, but it wouldn't make sense for the relay technicians troubleshooting on site in the substation.

Figure 3-80: Example HMI Data Presentment

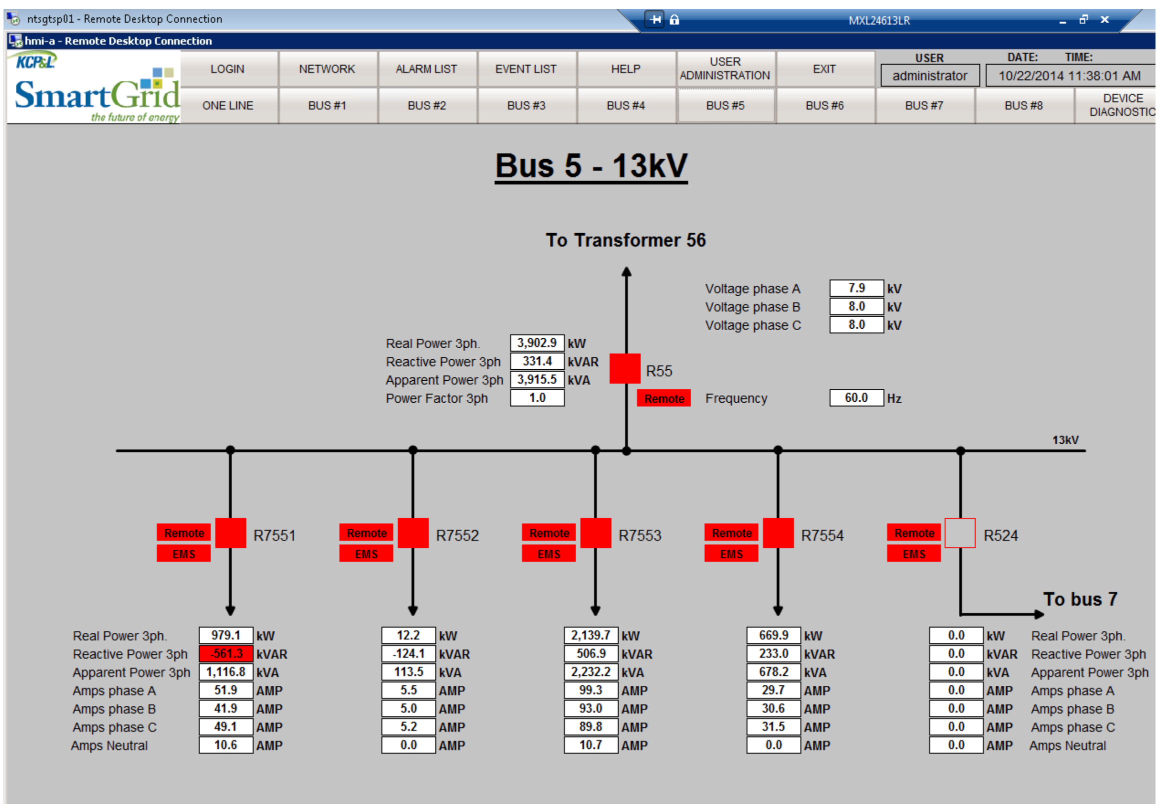


Figure 3-81: Example DMS Data Presentment

Feature Information

Device: 7553 Refresh

Attributes | Counts | SCADA | DNA

Name	Value
50CO - Ground - Enabled Status	Disabled
79CO - Reclose - Enabled Status	Enabled
Apparent Power - 3 Phase (kVA)	2232.201172
Apparent Power - Phase A (kVA)	782.987244
Apparent Power - Phase B (kVA)	736.866516
Apparent Power - Phase C (kVA)	687.147339
Breaker Failure	OK
Close Failure	OK
Contact Wear - 3 Phase	OK
Current - Average	92.376015
Current - Max - Neutral	106.400002
Current - Max - Phase A	308.5
Current - Max - Phase B	338.100006
Current - Max - Phase C	298.899994
Current - Negative Sequence	0
Current - Neutral	10.684598
Current - Phase A	99.296982
Current - Phase B	93.028397
Current - Phase C	89.752731
Current - Positive Sequence	75.763931
Current - Zero Sequence	0.98497
Current Imbalance	0
Device Status	Closed
EMS - DMS Indicator	EMS
Fault - Ground	OK
Fault - Phase A	OK
Fault - Phase B	OK
Fault - Phase C	OK
Feeder Lockout Operated	OK
Ground Neutral Overcurrent	OK
Hardware Alarm	OK
High Current Lockout	OK
Instantaneous	OK
Local - Remote	Remote
Loss of Potential	OK
Negative Sequence Overcurrent	OK
Over Under Frequency	OK
Phase Overcurrent	OK
Power Factor - 3 Phase	0.973242
Power Factor - Phase A	0.982442
Power Factor - Phase B	0.965589
Power Factor - Phase C	0.969046
Reactive Power - 3 Phase (kVAR)	506.903809
Reactive Power - Phase A (kVAR)	174.586487
Reactive Power - Phase B (kVAR)	181.18129
Reactive Power - Phase C (kVAR)	160.661209
Real Power - 3 Phase (kW)	2139.748535
Real Power - Phase A (kW)	766.05365
Real Power - Phase B (kW)	727.923157
Real Power - Phase C (kW)	668.274902
SICAM Device Comm Failure	OK
Slow Breaker Indication	OK
Software Alarm	OK
Trip Coil Monitor	OK
Under Frequency Trip	OK
Voltage - Negative Sequence (kV)	0.015705
Voltage - Phase A (kV)	7.884968
Voltage - Phase B (kV)	7.913466
Voltage - Phase C (kV)	7.906721
Voltage - Positive Sequence (kV)	7.84152
Voltage - Zero Sequence (kV)	0.030382
Voltage Imbalance	0.62398

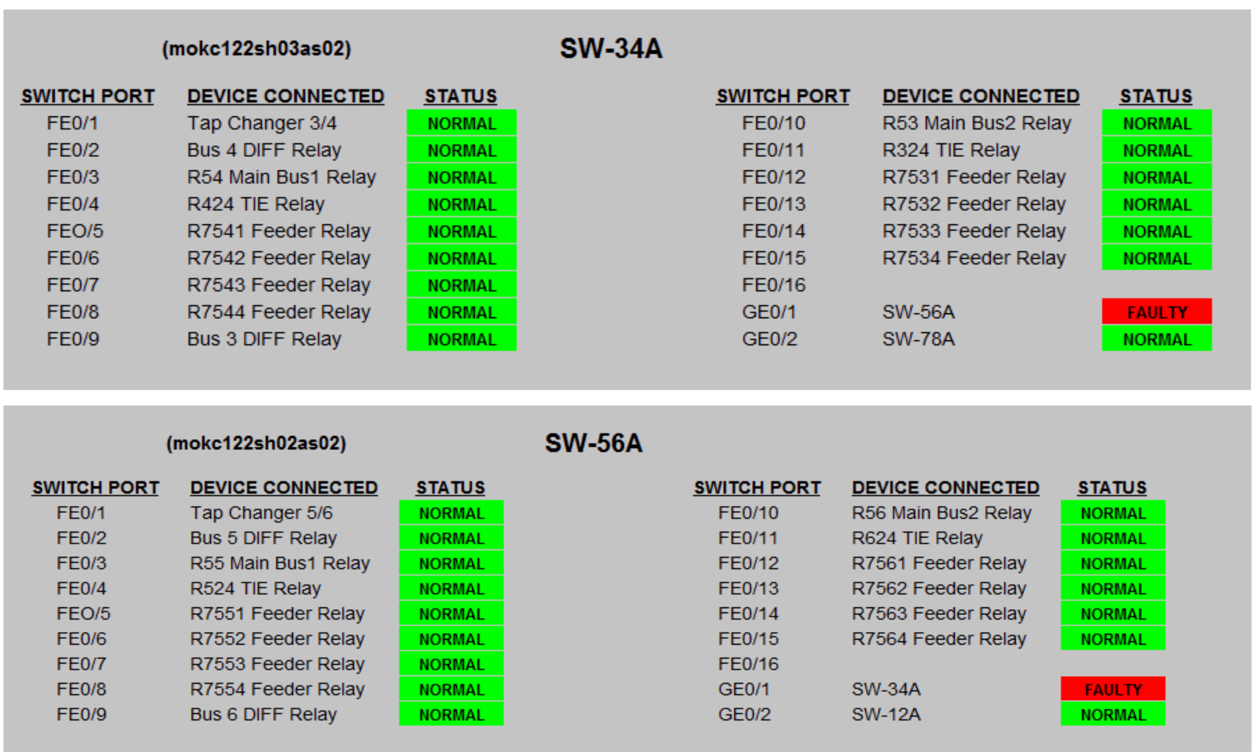
Right Click to Control SCADA points

3.4.5.2.2.3 Incident Identification and Avoidance

Once the substation and field device points lists were solidified, the devices were deployed, and the data started coming into the back office systems, KCP&L was able to use the incoming data for analysis. In three instances, access to this data helped KCP&L to discover potential problems and either avoid or minimize the associated issues.

- In August 2014, system faults led to gassing in a Midtown transformer. Early identification via the DMS, isolation of the faults, and closure of faults kept gassing to a minimum. This quick identification of transformer gassing allowed for prompt replacement of oil.
- While conducting the VVC operational testing, the voltage on a bus was marginally low and a tap changer was continually classified as non-responsive by the DMS. Upon further investigation, it became clear that the on-load tap changer was stuck in position 16. The tap changer control settings and tap changer circuitry were thoroughly investigated. A configuration issue in the tap changer circuitry was identified and rectified. The tap changer was then operational without any outage or equipment failure.
- In December 2013, a communications issue was discovered via the HMI. Figure 3-X shows the network status tabs in the HMI from that event – a faulty condition was detected between SW-34A and SW-56A. After a bit of troubleshooting, KCP&L determined that this issue was caused by a bad fiber. The fiber was replaced and the network status went back to normal.

Figure 3-82: HMI Network Screens Showing Faulty Status



(mokc122sh03as02) SW-34A

SWITCH PORT	DEVICE CONNECTED	STATUS	SWITCH PORT	DEVICE CONNECTED	STATUS
FE0/1	Tap Changer 3/4	NORMAL	FE0/10	R53 Main Bus2 Relay	NORMAL
FE0/2	Bus 4 DIFF Relay	NORMAL	FE0/11	R324 TIE Relay	NORMAL
FE0/3	R54 Main Bus1 Relay	NORMAL	FE0/12	R7531 Feeder Relay	NORMAL
FE0/4	R424 TIE Relay	NORMAL	FE0/13	R7532 Feeder Relay	NORMAL
FEO/5	R7541 Feeder Relay	NORMAL	FE0/14	R7533 Feeder Relay	NORMAL
FE0/6	R7542 Feeder Relay	NORMAL	FE0/15	R7534 Feeder Relay	NORMAL
FE0/7	R7543 Feeder Relay	NORMAL	FE0/16		
FE0/8	R7544 Feeder Relay	NORMAL	GE0/1	SW-56A	FAULTY
FE0/9	Bus 3 DIFF Relay	NORMAL	GE0/2	SW-78A	NORMAL

(mokc122sh02as02) SW-56A

SWITCH PORT	DEVICE CONNECTED	STATUS	SWITCH PORT	DEVICE CONNECTED	STATUS
FE0/1	Tap Changer 5/6	NORMAL	FE0/10	R56 Main Bus2 Relay	NORMAL
FE0/2	Bus 5 DIFF Relay	NORMAL	FE0/11	R624 TIE Relay	NORMAL
FE0/3	R55 Main Bus1 Relay	NORMAL	FE0/12	R7561 Feeder Relay	NORMAL
FE0/4	R524 TIE Relay	NORMAL	FE0/13	R7562 Feeder Relay	NORMAL
FEO/5	R7551 Feeder Relay	NORMAL	FE0/14	R7563 Feeder Relay	NORMAL
FE0/6	R7552 Feeder Relay	NORMAL	FE0/15	R7564 Feeder Relay	NORMAL
FE0/7	R7553 Feeder Relay	NORMAL	FE0/16		
FE0/8	R7554 Feeder Relay	NORMAL	GE0/1	SW-34A	FAULTY
FE0/9	Bus 6 DIFF Relay	NORMAL	GE0/2	SW-12A	NORMAL

3.4.5.2.2.4 HIS Data Archival and Analysis

The HIS deployment was very beneficial to the asset condition monitoring, as this system stores data from all of the substation and field devices that communicate with the data concentrator. The HIS obtains this data from the DMS and then maintains it for extraction and analysis. This system allows KCP&L to perform more thorough analysis after-the-fact, improving utility efficiency and reliability.

3.4.5.2.2.5 Issues and Corrective Actions

The following issues and corrective action were encountered during the performance of the Asset Condition Monitoring Information operational demonstration and analysis.

Table 3-62: Issues and Corrective Actions

Issue	Corrective Action
• Original deadbands were too narrow, leading to an overload of information reported at the data concentrator for analysis.	• Deadbands were increased to reflect appropriate levels for voltage, reactive power, and other categories for measurement. The project team monitored data at the DMS to see how frequently information was being reported, and then adjusted accordingly.
• Non-coincidence of reported data was problematic, as data never gets reported simultaneously because each data point has its own deadband.	• Used the HIS interpolation to approximate individual reading when simultaneous data was needed for event analysis.
• Volume of data proved problematic for the substation data concentrator.	• The team adjusted deadbands, tuned settings, and eventually replaced the SICAM hardware to accommodate data volumes.
• Because of work reporting and accounting system limitations and the size of the pilot, KCP&L wasn't able to allocate distribution equipment maintenance costs.	• Most field based equipment being monitored was new to KCP&L; therefore there is no Distribution Equipment Maintenance Cost savings. • Substation based equipment has some existing SCADA monitoring and due to the work and accounting system limitations the project team chose to not claim any Reduced Distribution Equipment Maintenance Cost savings.

3.4.5.2.3 Findings

The results obtained in the execution and analyses of the Asset Conditioning Monitoring operational demonstration are summarized in the sections below.

3.4.5.2.3.1 Discussion

Through the implementation and operation of the substation protection network and wireless mesh field network, KCP&L greatly increased the device information available to various utility personnel. The data points returned for each device was used for both operational purposes and asset conditioning monitoring.

All substation and field device data was sent to the data concentrator, and then subsets of the data were sent to various systems. The relevant data for each device type was displayed on the relevant user interface. Access to this data empowered utility personnel with maintenance and information data that had not been available previously. KCP&L learned about potential issues in real time, and were able to troubleshoot and repair equipment quickly and efficiently.

Lastly, through the data historian, KCP&L can store device data and access it over time to analyze events, track quantity of device operations, and investigate unexpected analogs.

Now that points have been determined and the infrastructure is in place, operations will continue to be refined to boost efficiency and reliability.

3.4.5.2.3.2 Expectations vs. Actuals

The following table provides a comparison of the Expected Results and the Actual Outcomes for the Asset Condition Monitoring operational demonstration.

Table 3-63: Expected Results vs. Actual Outcome

Expected Results	Actual Outcome
• Analysis of condition monitoring data from currently available industry equipment controls will provide experience and learning for the industry.	• Through KCP&L's thorough device data point selection process, much insight was gained regarding the appropriate data to be used for condition monitoring. KCP&L has shared experiences from this multi-phase process to the industry through conferences and papers.
• Implementation of report-by-exception condition monitoring data from current industry equipment controls will provide experience and learning for the industry.	• This design decision resulted in a number of implementation, operation, and maintenance insights – some due to the specific vendor technologies, and others generic to any report-by-exception deployment. All of these hurdles have helped KCP&L to deepen its understanding, and the lessons learned have been passed along to the industry through conferences, papers, and conversations with vendors.
• Demonstrate how remote asset condition reporting can reduce operation and maintenance costs as conditions can be determined remotely in real time.	• The bad fiber incident described in the Incident Identification and Avoidance section above is an example of how remote access to asset information can reduce O&M costs. Without the HMI network screen, KCP&L might not have known there was an issue until an event occurred at the substation. At that point, KCP&L would have had to spend time troubleshooting to determine if the problem was with the network or the substation device itself. By having the detailed network information on the HMI, KCP&L avoided lots of on-site troubleshooting costs..
• Record any actions based on real-time feedback that were used to help prevent component failures, thus improving reliability and further reducing operation and maintenance costs.	• The Incident Identification and Avoidance section above describes two specific incidents that occurred in which the information obtained helped KCP&L to discover potential problems and avoid potential component failures. For the new transformer gassing incident, the early identification helped to identify a loose internal connection preventing a potential transformer failure. • For the tap changer incident, the project team discovering that the tap changer was actually stuck on the lowest tap and was non responsive to operational commands. In this incident, the monitoring helped identify a tap changer configuration issue that could have otherwise been identified only after an outage, voltage complaints or equipment failure.

3.4.5.2.3.3 Computational Tool Factors

The following table lists the values derived from the Asset Condition Monitoring operational demonstration analysis that will be used as inputs to the SmartGrid Computational Tool.

Table 3-64: Computational Tool Values

Name	Description	Calculated Value
Capital Replacement of Failed Equipment	Capital expenditures related to replacing failed equipment within the project scope.	$1,250,000
Portion Caused by Lack of Condition Diagnosis	The percentage of equipment failures caused primarily by a lack condition diagnosis	100%
Reduced Distribution Equipment Maintenance Cost	Reduced annual cost of distribution equipment maintenance. Online diagnosis and reporting of equipment condition could reduce or eliminate the need to send people out to check or maintain equipment resulting in a cost savings.	$0

- Capital Replacement of Failed Equipment ($) – This value is based on the avoided cost of replacing a failed substation transformer.
- Portion Caused by Lack of Condition Analysis (%) – This is 100% since the project team is using actual avoided costs and not an estimate based on total company equipment replacement costs.
- Reduced Distribution Equipment Maintenance Cost – For the SGDP, this value could not be segregated from other distribution maintenance costs and since the cost savings were determined to be minimal, no equipment maintenance cost savings benefit was taken.

3.4.5.2.4 Lessons Learned

Throughout the demonstration of the Asset Condition Monitoring function, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- KCP&L identified the data points that could be utilized for asset management purposes, both for substation and for field devices.
- Non-coincidence of data leads to complications. While the team used logic in establishing deadbands — giving associated items (voltage and current, for example) similar deadbands, so that they would trigger at the same time and, therefore, offer clues about causes of incidents and guidance for changes — the process could be adjusted to be even more effective. It would be advantageous to change industry standards so that when the most significant item (chosen by the user) hits its deadband, all other analog points would be reported simultaneously, by exception.
- Current DMSs aren't advanced to the point where they can present a desired level of data for all devices. Improved data presentment is necessary for users, who are awash in data coming back to them. Industry should consider selecting certain points to always be displayed, with options for selecting other points for viewing by scrolling down the screen. Having the ability to filter out asset management points from operational points would be useful.

3.4.5.3 Substation Hierarchical Control

Substation Hierarchical Control is a demonstration of one aspect of the Diagnosis & Notification of Equipment Condition function.

3.4.5.3.1 Overview

The following sections provide an overview of the operational, demonstration, testing, and evaluation methodology used for the Substation Hierarchical Control operational demonstration.

3.4.5.3.1.1 Description

An IEC 61850 compliant substation automation network will be installed in the Midtown Substation along with automation control components to enable robust distributed automation functionality. The automation control components to be implemented include a substation communication controller for both substation and field devices; distributed automation controllers; and an HMI for local monitoring and control of substation devices. The substation automation network will provide distributed intelligence at the substation that will enable execution of automated control operations based on feedback from real-time monitoring of transformers, relays, cap banks, and other field equipment installed throughout the circuits.

3.4.5.3.1.2 Expected Results

The Technical Demonstration of the Substation Hierarchical Control was expected to yield the following:

- Evaluation of existing control system technologies to implement a distributed hierarchical control system will provide experience and learning for the industry.
- Remote monitoring and operation of all substation equipment from a single location within the substation will provide an increased level of safety for the field operator.

3.4.5.3.1.3 Benefit Analysis Method/Factors

The Technical Demonstration of this application will not contribute to the project Benefits Analysis.

3.4.5.3.1.4 Demonstration Methodology

The following points provide an overview of how the technical demonstration of this application will be accomplished:

- A fiber substation protection network will be deployed at Midtown substation to enable communications to substation devices, and a Tropos wireless mesh network will be deployed throughout the SGDP area to enable communications to field devices.
- Intelligent Electronic Devices (IEDs) will be deployed in Midtown substation and along the 11 designated smart grid feeders extending from Midtown substation.
- Data from the IEDs will be reported to a centralized data concentrator, and then sent to the substation DCADA and HMI for monitoring purposes.
- Verify that the DMS and the DCADA take similar action when given the same device statuses, depending on which system is in control of the substation.
- Verify that the HMI correctly reflects the substation device data in addition to the network status data.
- Verify that the user can control substation devices from the HMI.

3.4.5.3.1.5 Analytical Methodology

The Technical Demonstration of this application does not require any analytical calculations.

3.4.5.3.2 Plan Execution and Analysis

The following sections describe how the plan was executed, plus analysis regarding the Substation Hierarchical Control operational demonstration.

3.4.5.3.2.1 SICAM Demonstration

The substation DDC acts as a traffic cop and communicates with a number of other smart grid systems. For the SGDP, the DDC installed was the Siemens SICAM PAS. This system is described in detail in Section 2.2.3.2. The systems that the SICAM interacted with are as follows:

- DMS
- DCADA
- HMI
- Field devices (via Tropos network)
- Substation devices

3.4.5.3.2.2 HMI Demonstration

The substation HMI is a graphical user interface (GUI) and local controller for the devices located inside the Midtown Substation. It doesn't include any information for the field devices located outside the substation walls. It allows technicians to see the status of all substation devices at once, saving personnel time from going from one switch house to the next. It also allows the technicians to monitor and control breakers from the safety of the control house. This system is described in detail in Section 2.2.3.3.

Figure 3-83 through Figure 3-87 below show some of the views that the HMI can provide — a single-line view, a single-bus view, the network equipment view, the alarm list, and the event log.

Figure 3-83: HMI Single-Line View

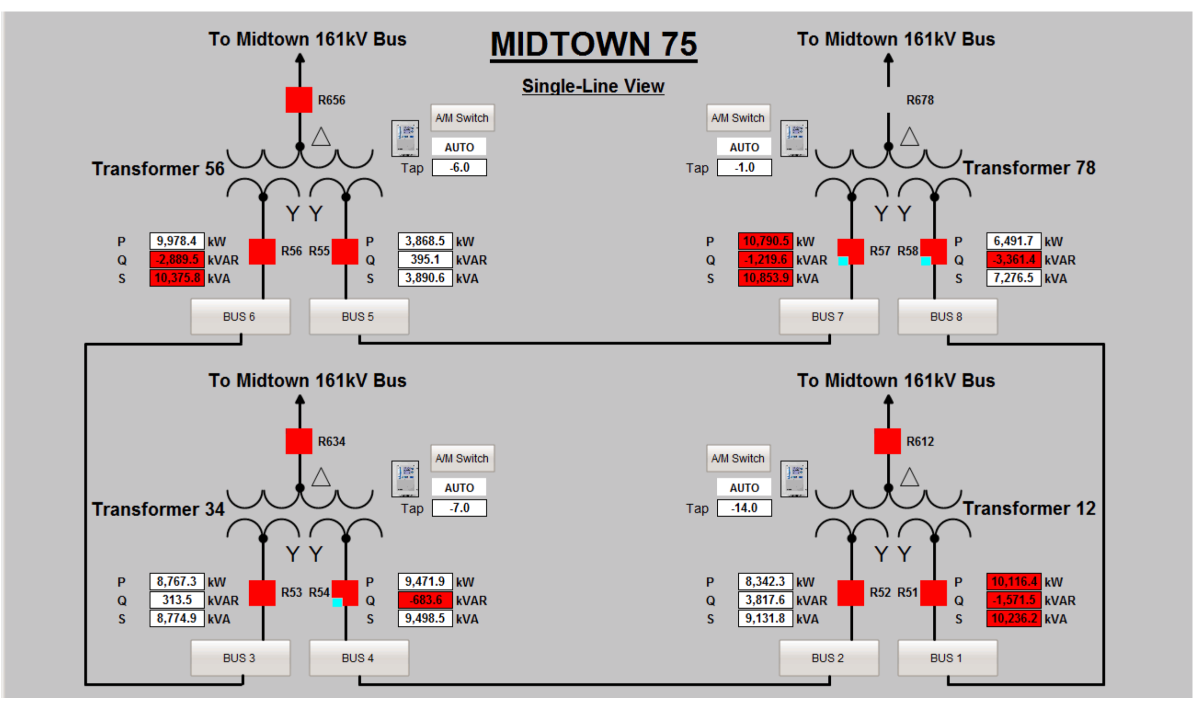


Figure 3-84: HMI Single-Bus View

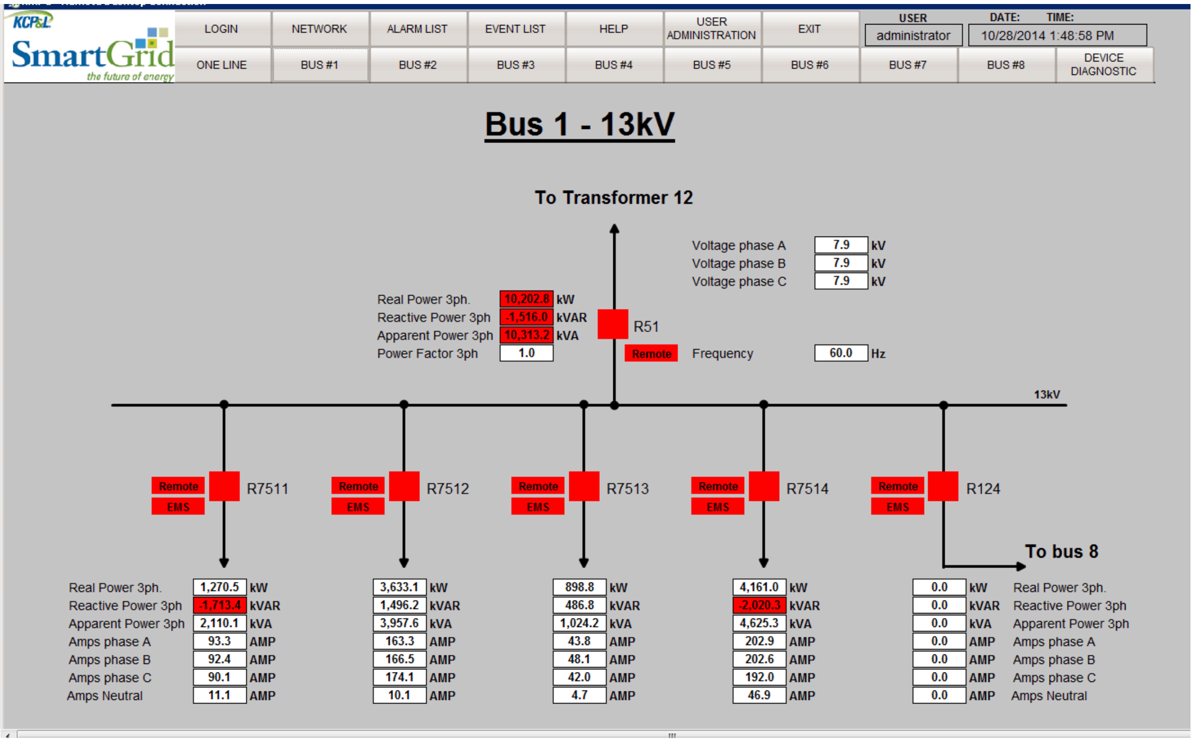


Figure 3-85: HMI Network Overview

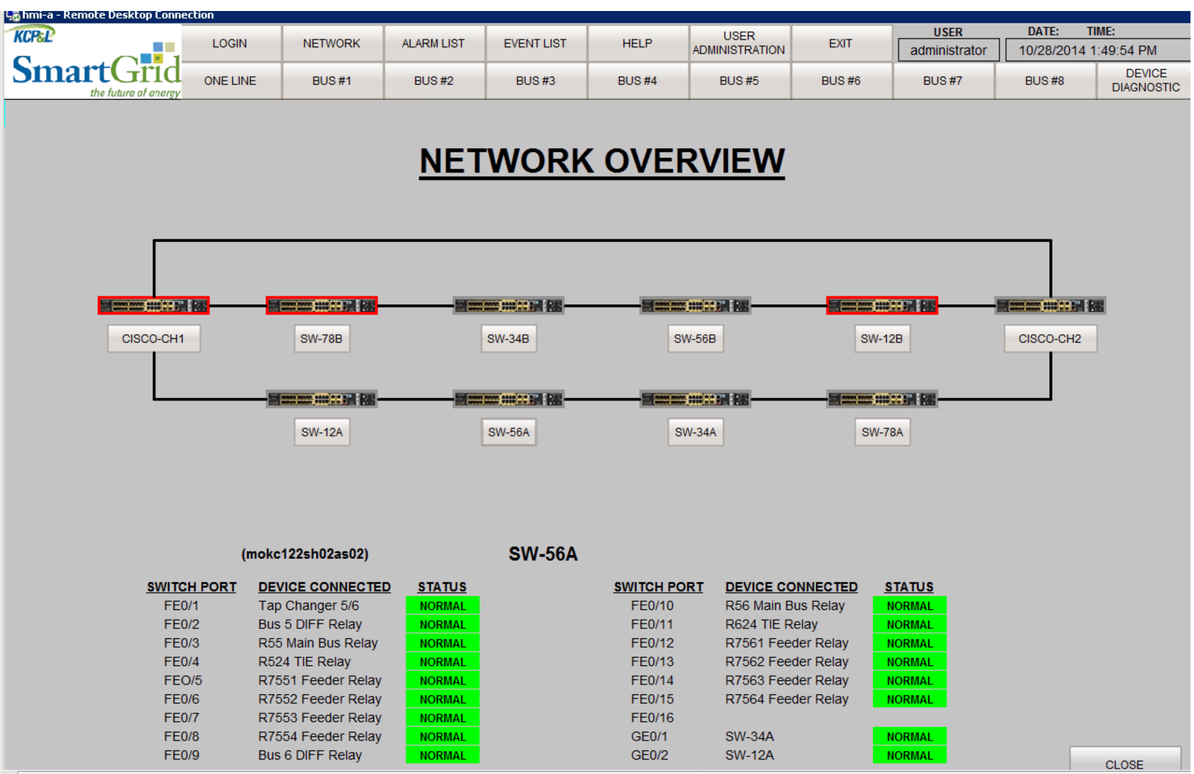
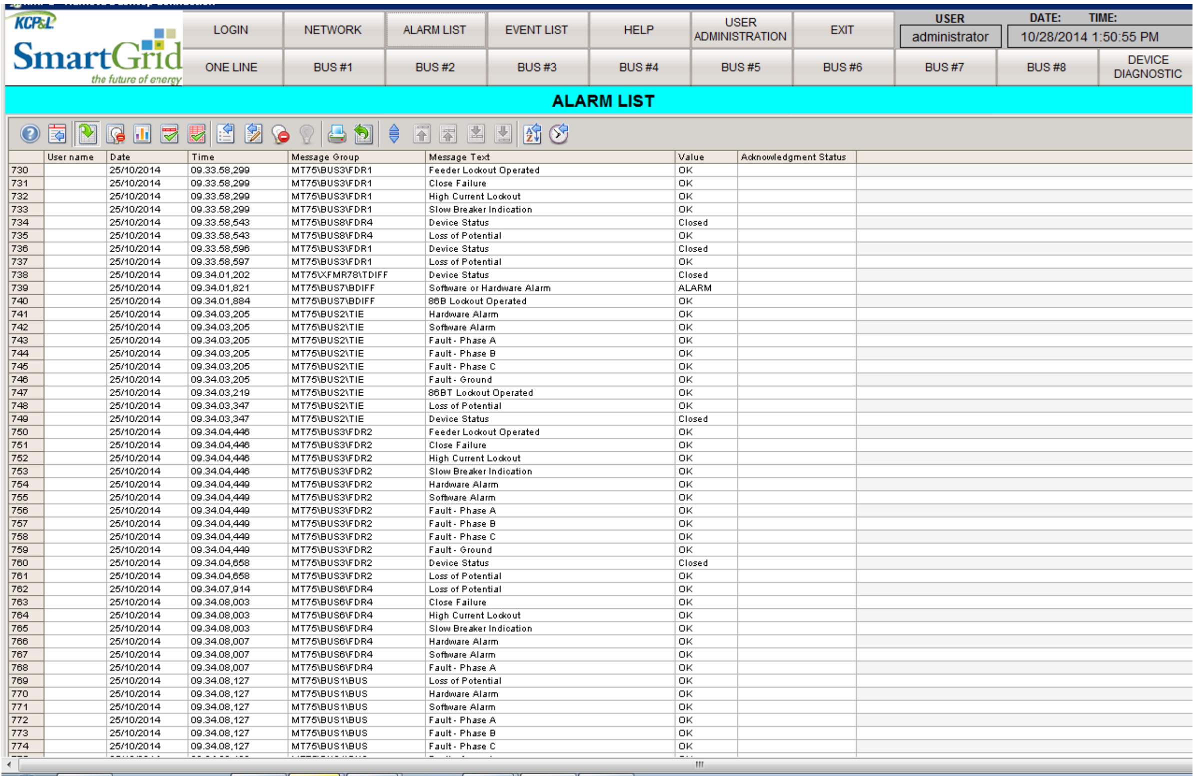
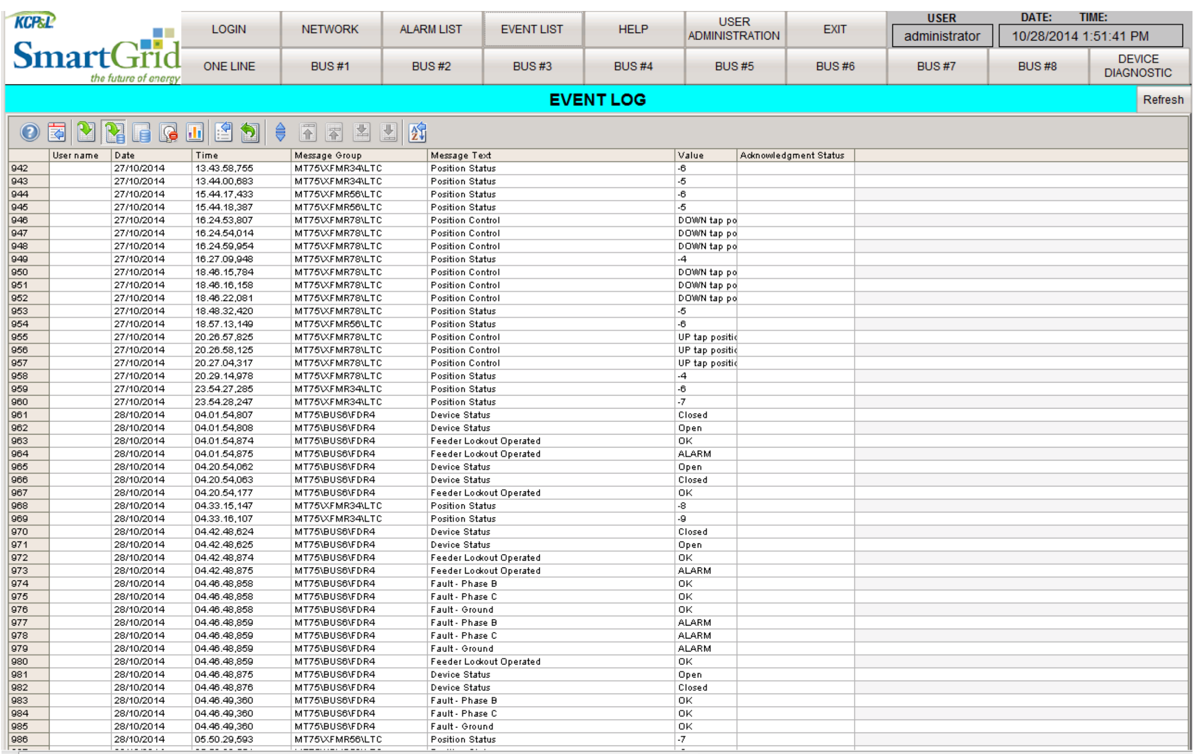


Figure 3-86: HMI Alarm List View



	User name	Date	Time	Message Group	Message Text	Value	Acknowledgment Status
730		25/10/2014	09.33.58,299	MT75\BUS3\FDR1	Feeder Lockout Operated	OK	
731		25/10/2014	09.33.58,299	MT75\BUS3\FDR1	Close Failure	OK	
732		25/10/2014	09.33.58,299	MT75\BUS3\FDR1	High Current Lockout	OK	
733		25/10/2014	09.33.58,299	MT75\BUS3\FDR1	Slow Breaker Indication	OK	
734		25/10/2014	09.33.58,543	MT75\BUS8\FDR4	Device Status	Closed	
735		25/10/2014	09.33.58,543	MT75\BUS8\FDR4	Loss of Potential	OK	
736		25/10/2014	09.33.58,596	MT75\BUS3\FDR1	Device Status	Closed	
737		25/10/2014	09.33.58,597	MT75\BUS3\FDR1	Loss of Potential	OK	
738		25/10/2014	09.34.01,202	MT75\XFMR78\TDIFF	Device Status	Closed	
739		25/10/2014	09.34.01,821	MT75\BUS7\BDIFF	Software or Hardware Alarm	ALARM	
740		25/10/2014	09.34.01,884	MT75\BUS7\BDIFF	86B Lockout Operated	OK	
741		25/10/2014	09.34.03,205	MT75\BUS2\TIE	Hardware Alarm	OK	
742		25/10/2014	09.34.03,205	MT75\BUS2\TIE	Software Alarm	OK	
743		25/10/2014	09.34.03,205	MT75\BUS2\TIE	Fault - Phase A	OK	
744		25/10/2014	09.34.03,205	MT75\BUS2\TIE	Fault - Phase B	OK	
745		25/10/2014	09.34.03,205	MT75\BUS2\TIE	Fault - Phase C	OK	
746		25/10/2014	09.34.03,205	MT75\BUS2\TIE	Fault - Ground	OK	
747		25/10/2014	09.34.03,219	MT75\BUS2\TIE	86BT Lockout Operated	OK	
748		25/10/2014	09.34.03,347	MT75\BUS2\TIE	Loss of Potential	OK	
749		25/10/2014	09.34.03,347	MT75\BUS2\TIE	Device Status	Closed	
750		25/10/2014	09.34.04,446	MT75\BUS3\FDR2	Feeder Lockout Operated	OK	
751		25/10/2014	09.34.04,446	MT75\BUS3\FDR2	Close Failure	OK	
752		25/10/2014	09.34.04,446	MT75\BUS3\FDR2	High Current Lockout	OK	
753		25/10/2014	09.34.04,446	MT75\BUS3\FDR2	Slow Breaker Indication	OK	
754		25/10/2014	09.34.04,449	MT75\BUS3\FDR2	Hardware Alarm	OK	
755		25/10/2014	09.34.04,449	MT75\BUS3\FDR2	Software Alarm	OK	
756		25/10/2014	09.34.04,449	MT75\BUS3\FDR2	Fault - Phase A	OK	
757		25/10/2014	09.34.04,449	MT75\BUS3\FDR2	Fault - Phase B	OK	
758		25/10/2014	09.34.04,449	MT75\BUS3\FDR2	Fault - Phase C	OK	
759		25/10/2014	09.34.04,449	MT75\BUS3\FDR2	Fault - Ground	OK	
760		25/10/2014	09.34.04,658	MT75\BUS3\FDR2	Device Status	Closed	
761		25/10/2014	09.34.04,658	MT75\BUS3\FDR2	Loss of Potential	OK	
762		25/10/2014	09.34.07,914	MT75\BUS6\FDR4	Loss of Potential	OK	
763		25/10/2014	09.34.08,003	MT75\BUS6\FDR4	Close Failure	OK	
764		25/10/2014	09.34.08,003	MT75\BUS6\FDR4	High Current Lockout	OK	
765		25/10/2014	09.34.08,003	MT75\BUS6\FDR4	Slow Breaker Indication	OK	
766		25/10/2014	09.34.08,007	MT75\BUS6\FDR4	Hardware Alarm	OK	
767		25/10/2014	09.34.08,007	MT75\BUS6\FDR4	Software Alarm	OK	
768		25/10/2014	09.34.08,007	MT75\BUS6\FDR4	Fault - Phase A	OK	
769		25/10/2014	09.34.08,127	MT75\BUS1\BUS	Loss of Potential	OK	
770		25/10/2014	09.34.08,127	MT75\BUS1\BUS	Hardware Alarm	OK	
771		25/10/2014	09.34.08,127	MT75\BUS1\BUS	Software Alarm	OK	
772		25/10/2014	09.34.08,127	MT75\BUS1\BUS	Fault - Phase A	OK	
773		25/10/2014	09.34.08,127	MT75\BUS1\BUS	Fault - Phase B	OK	
774		25/10/2014	09.34.08,127	MT75\BUS1\BUS	Fault - Phase C	OK	

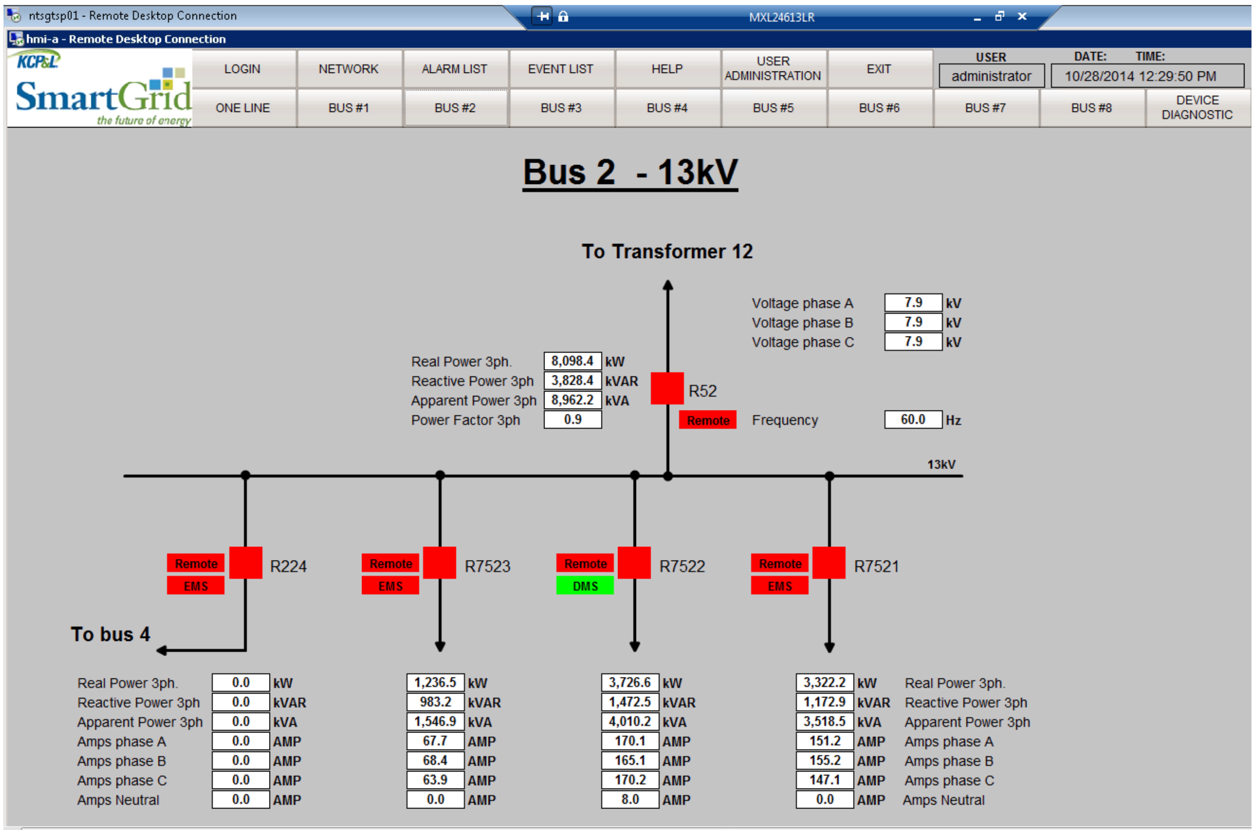
Figure 3-87: HMI Event Log View



	User name	Date	Time	Message Group	Message Text	Value	Acknowledgment Status
942		27/10/2014	13.43.58,755	MT75\XFMR34\LTC	Position Status	-6	
943		27/10/2014	13.44.00,683	MT75\XFMR34\LTC	Position Status	-5	
944		27/10/2014	15.44.17,433	MT75\XFMR56\LTC	Position Status	-6	
945		27/10/2014	15.44.18,387	MT75\XFMR56\LTC	Position Status	-5	
946		27/10/2014	16.24.53,807	MT75\XFMR78\LTC	Position Control	DOWN tap po	
947		27/10/2014	16.24.54,014	MT75\XFMR78\LTC	Position Control	DOWN tap po	
948		27/10/2014	16.24.59,954	MT75\XFMR78\LTC	Position Control	DOWN tap po	
949		27/10/2014	16.27.09,948	MT75\XFMR78\LTC	Position Status	-4	
950		27/10/2014	18.46.15,784	MT75\XFMR78\LTC	Position Control	DOWN tap po	
951		27/10/2014	18.46.16,158	MT75\XFMR78\LTC	Position Control	DOWN tap po	
952		27/10/2014	18.46.22,081	MT75\XFMR78\LTC	Position Control	DOWN tap po	
953		27/10/2014	18.48.32,420	MT75\XFMR78\LTC	Position Status	-5	
954		27/10/2014	18.57.13,149	MT75\XFMR56\LTC	Position Status	-6	
955		27/10/2014	20.26.57,825	MT75\XFMR78\LTC	Position Control	UP tap positic	
956		27/10/2014	20.26.58,125	MT75\XFMR78\LTC	Position Control	UP tap positic	
957		27/10/2014	20.27.04,317	MT75\XFMR78\LTC	Position Control	UP tap positic	
958		27/10/2014	20.29.14,978	MT75\XFMR78\LTC	Position Status	-4	
959		27/10/2014	23.54.27,285	MT75\XFMR34\LTC	Position Status	-6	
960		27/10/2014	23.54.28,247	MT75\XFMR34\LTC	Position Status	-7	
961		28/10/2014	04.01.54,807	MT75\BUS6\FDR4	Device Status	Closed	
962		28/10/2014	04.01.54,808	MT75\BUS6\FDR4	Device Status	Open	
963		28/10/2014	04.01.54,874	MT75\BUS6\FDR4	Feeder Lockout Operated	OK	
964		28/10/2014	04.01.54,875	MT75\BUS6\FDR4	Feeder Lockout Operated	ALARM	
965		28/10/2014	04.20.54,062	MT75\BUS6\FDR4	Device Status	Open	
966		28/10/2014	04.20.54,063	MT75\BUS6\FDR4	Device Status	Closed	
967		28/10/2014	04.20.54,177	MT75\BUS6\FDR4	Feeder Lockout Operated	OK	
968		28/10/2014	04.33.15,147	MT75\XFMR34\LTC	Position Status	-8	
969		28/10/2014	04.33.16,107	MT75\XFMR34\LTC	Position Status	-9	
970		28/10/2014	04.42.48,624	MT75\BUS6\FDR4	Device Status	Closed	
971		28/10/2014	04.42.48,625	MT75\BUS6\FDR4	Device Status	Open	
972		28/10/2014	04.42.48,874	MT75\BUS6\FDR4	Feeder Lockout Operated	OK	
973		28/10/2014	04.42.48,875	MT75\BUS6\FDR4	Feeder Lockout Operated	ALARM	
974		28/10/2014	04.46.48,858	MT75\BUS6\FDR4	Fault - Phase B	OK	
975		28/10/2014	04.46.48,858	MT75\BUS6\FDR4	Fault - Phase C	OK	
976		28/10/2014	04.46.48,858	MT75\BUS6\FDR4	Fault - Ground	OK	
977		28/10/2014	04.46.48,859	MT75\BUS6\FDR4	Fault - Phase B	ALARM	
978		28/10/2014	04.46.48,859	MT75\BUS6\FDR4	Fault - Phase C	ALARM	
979		28/10/2014	04.46.48,859	MT75\BUS6\FDR4	Fault - Ground	ALARM	
980		28/10/2014	04.46.48,859	MT75\BUS6\FDR4	Feeder Lockout Operated	OK	
981		28/10/2014	04.46.48,875	MT75\BUS6\FDR4	Device Status	Open	
982		28/10/2014	04.46.48,876	MT75\BUS6\FDR4	Device Status	Closed	
983		28/10/2014	04.46.49,360	MT75\BUS6\FDR4	Fault - Phase B	OK	
984		28/10/2014	04.46.49,360	MT75\BUS6\FDR4	Fault - Phase C	OK	
985		28/10/2014	04.46.49,360	MT75\BUS6\FDR4	Fault - Ground	OK	
986		28/10/2014	05.50.29,593	MT75\XFMR56\LTC	Position Status	-7	

KCP&L's existing Energy Management System (EMS) for the transmission system has visibility and control capabilities down to the feeder breakers in the substation. For the SGDP, the feeder breakers were also included as part of the distribution system and could be monitored and controlled via the DMS, DCADA, and HMI. As a result, an EMS/DMS control toggle was created in the EMS so that the Transmission System Operators could pass control of the 11 SmartGrid feeder breakers downstream to the DMS. An indicator was also added to the HMI so that the user could easily determine which feeders were currently under the control of which system.

Figure 3-88: HMI EMS/DMS Control Indicator



As shown in the screenshot above, each feeder breaker can only be controlled by one system at a time — either the EMS or the DMS. In this example, feeder R7522 is currently under the control of the DMS, whereas feeders R224, R7523, and R7521 are all currently under the control of the EMS.

3.4.5.3.2.3 DCADA Demonstration

The DCADA system implementation is described in detail in Section 2.2.3.5. For the purposes of the substation hierarchical control demonstration, there are two main topics worth discussing.

Model management between the DMS and the DCADA was a critical component of the project hierarchical control, as it was imperative that the two systems have the same view of the network model at any time. The transfer of model updates between the centralized DMS and the localized DCADA was done using a Siemens proprietary format. Siemens had services in place so that when the model was updated in the DMS, the update was also sent to the DCADA to keep the two systems in check.

The second major component of the DCADA demonstration for the substation hierarchical control was verifying that the First Responder Applications yielded the same results whether run at the DCADA or the DMS. KCP&L primarily ran the first responder applications from the DMS. Refer to Sections 3.4.1, 3.4.2, and 3.4.3 for a full discussion on the tests of these functionalities. In addition to these ongoing tests at the DMS level, KCP&L also tested out all of the first responder applications at the DCADA to ensure that the systems generated the same results. See Figures 3-X through 3-XX below for results of the first responder applications from both the DMS and the DCADA. The consistent results also show that the two systems had synchronized network models.

Figure 3-89 and Figure 3-90 below show that running Distribution System Power Flow yielded the same results when run from the DMS and from the DCADA.

Figure 3-89: DSPF via the DMS

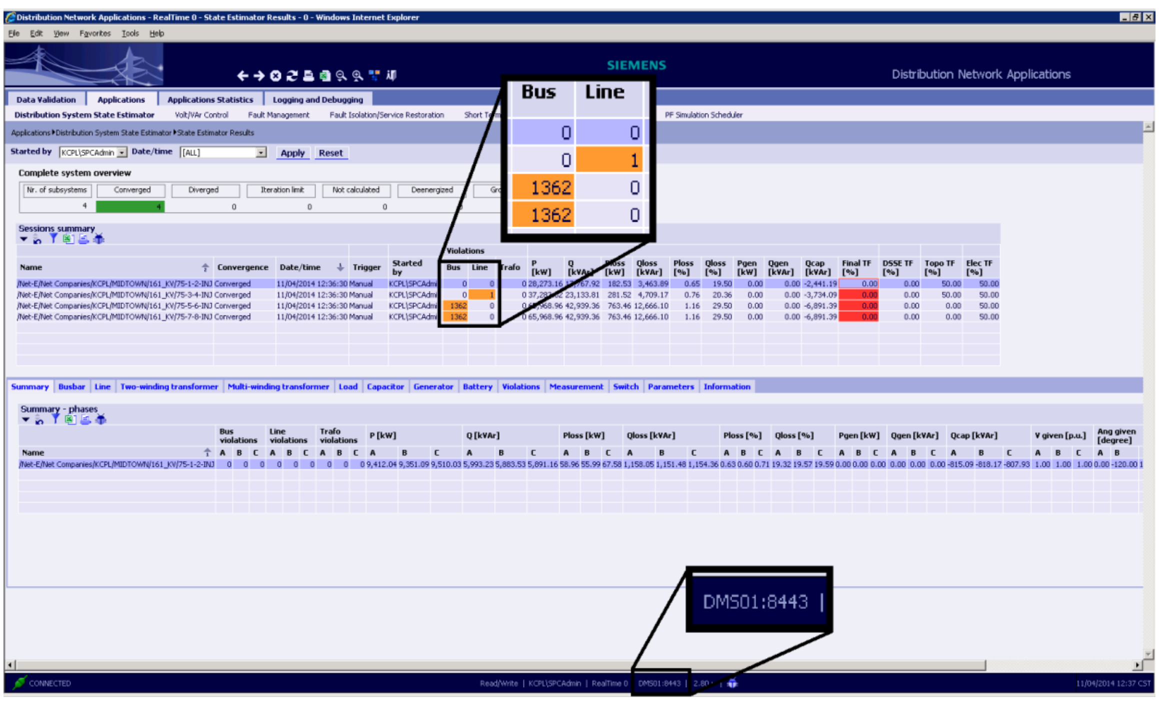


Figure 3-90: DSPF via the DCADA

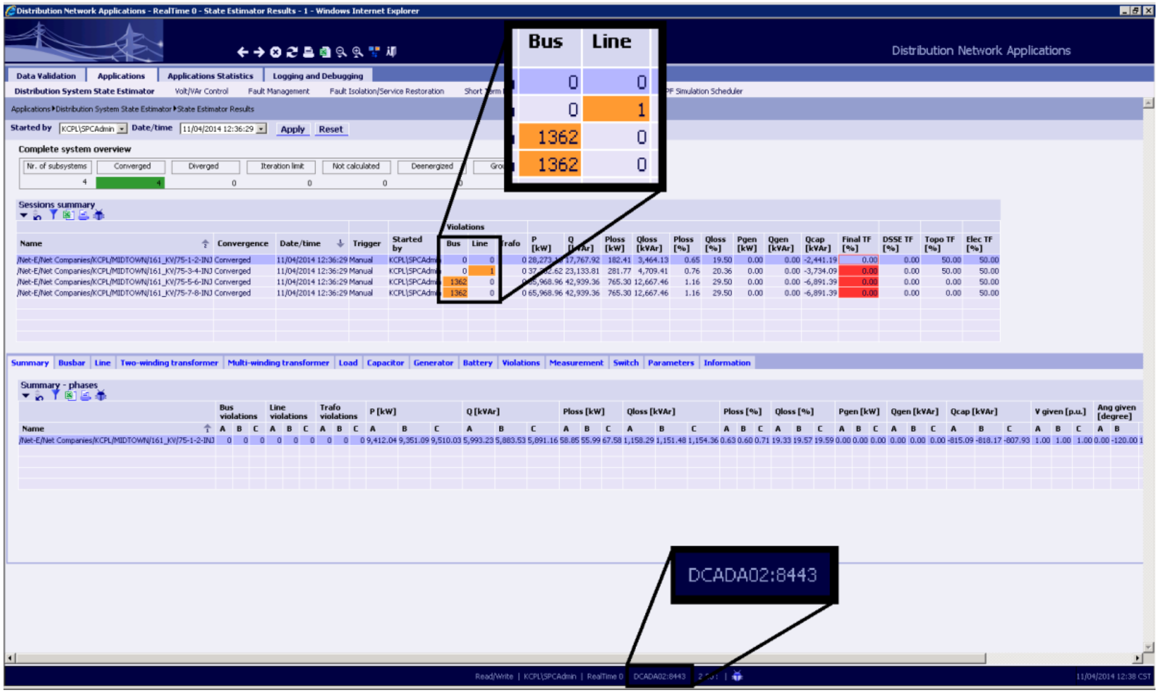


Figure 3-91 and Figure 3-92 show the results of VVC. As the screenshots show, the two systems yielded the same solution with the same nine (9) steps (albeit in different order).

Figure 3-91: VVC via the DMS

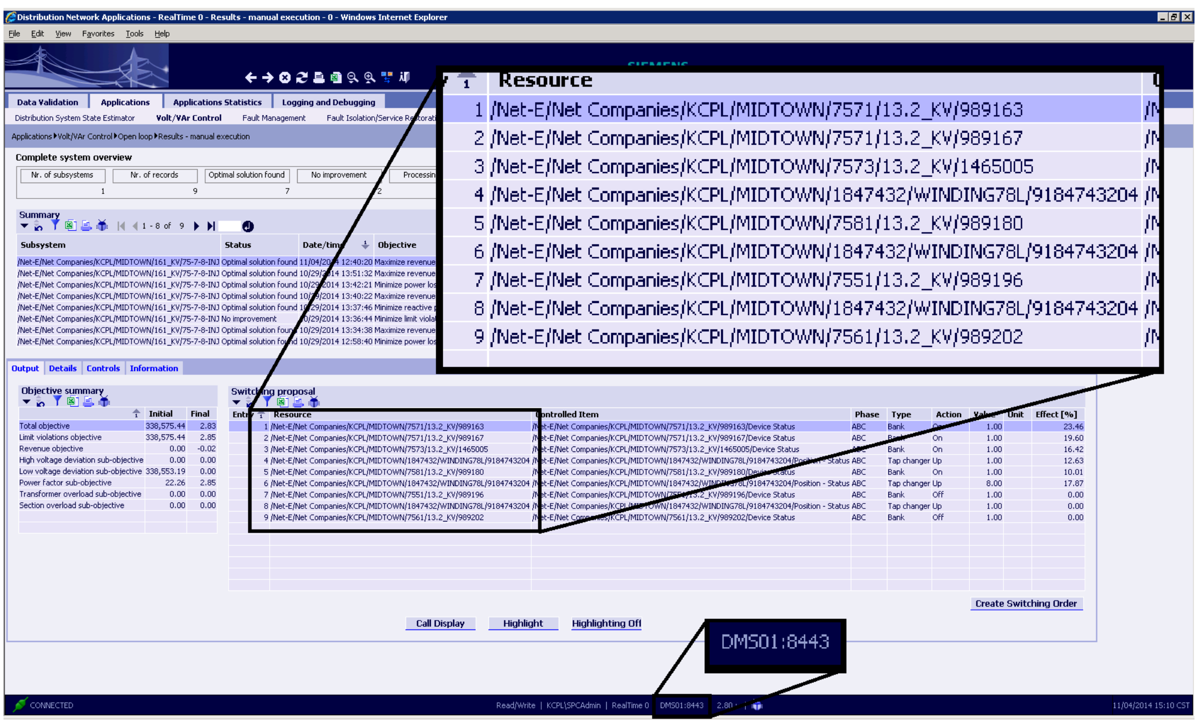
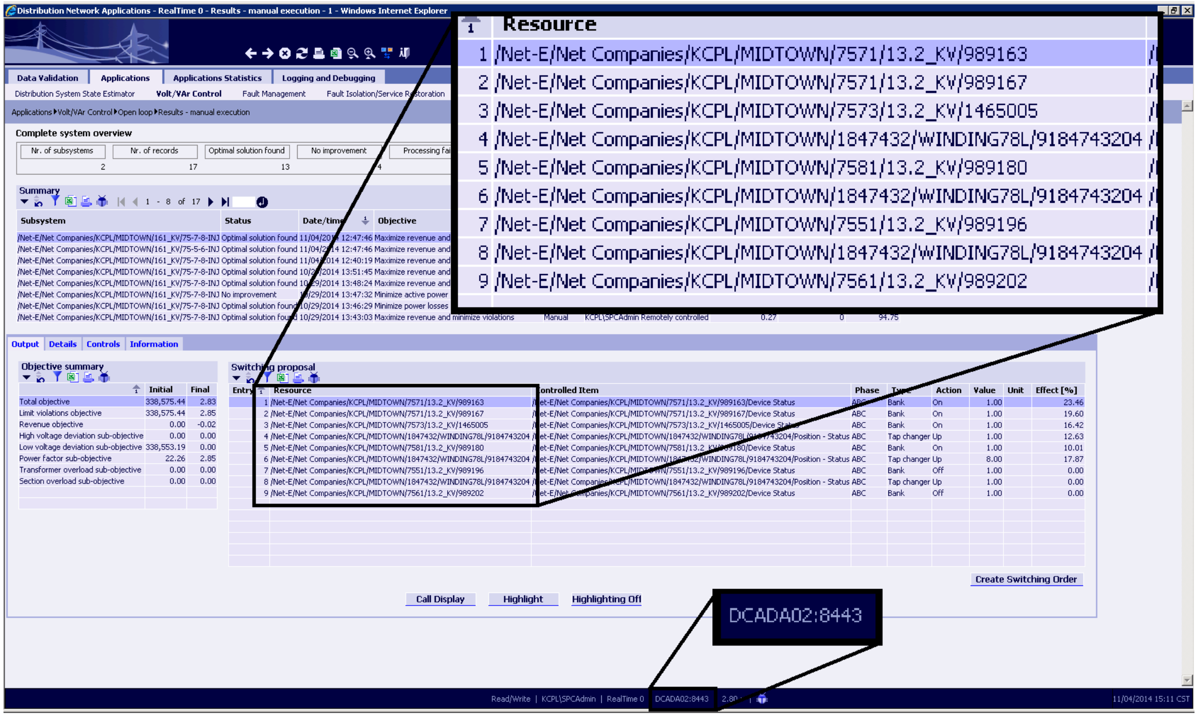


Figure 3-92: VVC via the DCADA



As shown in Figure 3-93 and Figure 3-94 below, Feeder Load Transfer yielded the same result when run from both the DMS and the DCADA. In both cases, no solution was found. As the screenshots show, the same initially opened switches were used when FLT was run from both systems.

Figure 3-93: FLT via the DMS

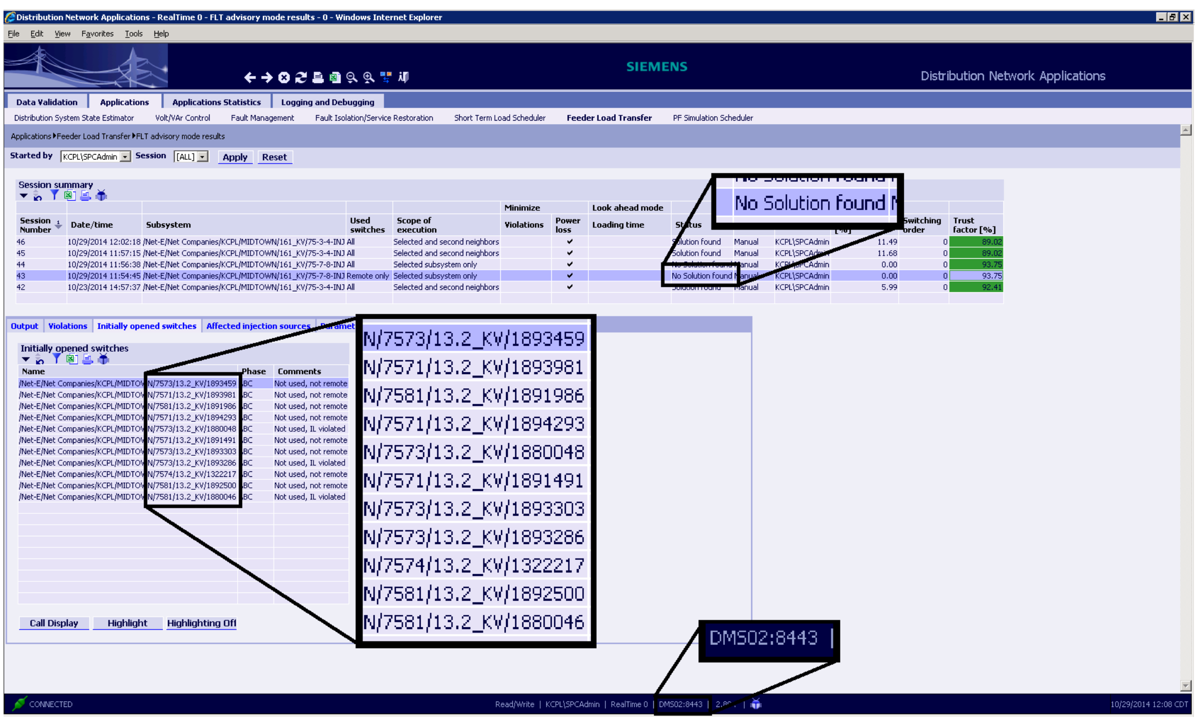
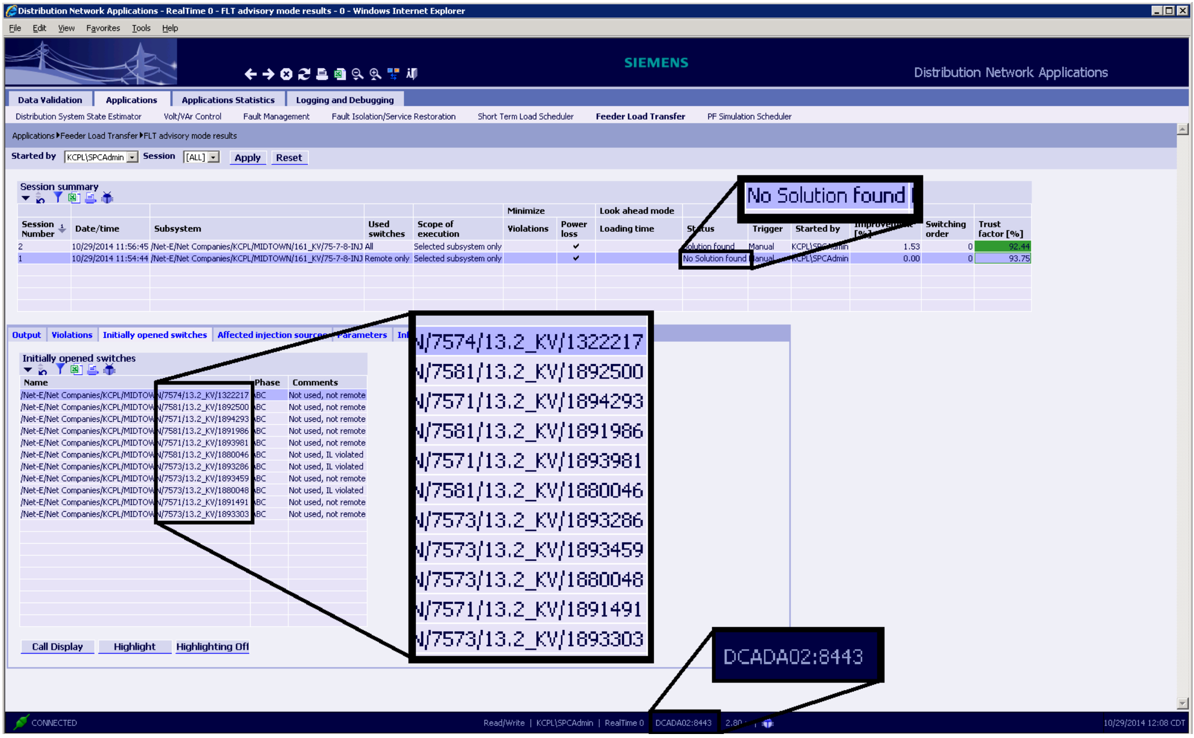


Figure 3-94: FLT via the DCADA



As shown in Figure 3-95 and Figure 3-96 below, Fault Isolation and Service Restoration yielded similar results when run from both the DMS and the DCADA. Both suggested the same switching proposal —to open feeder 7561.

Figure 3-95: FISR via the DMS

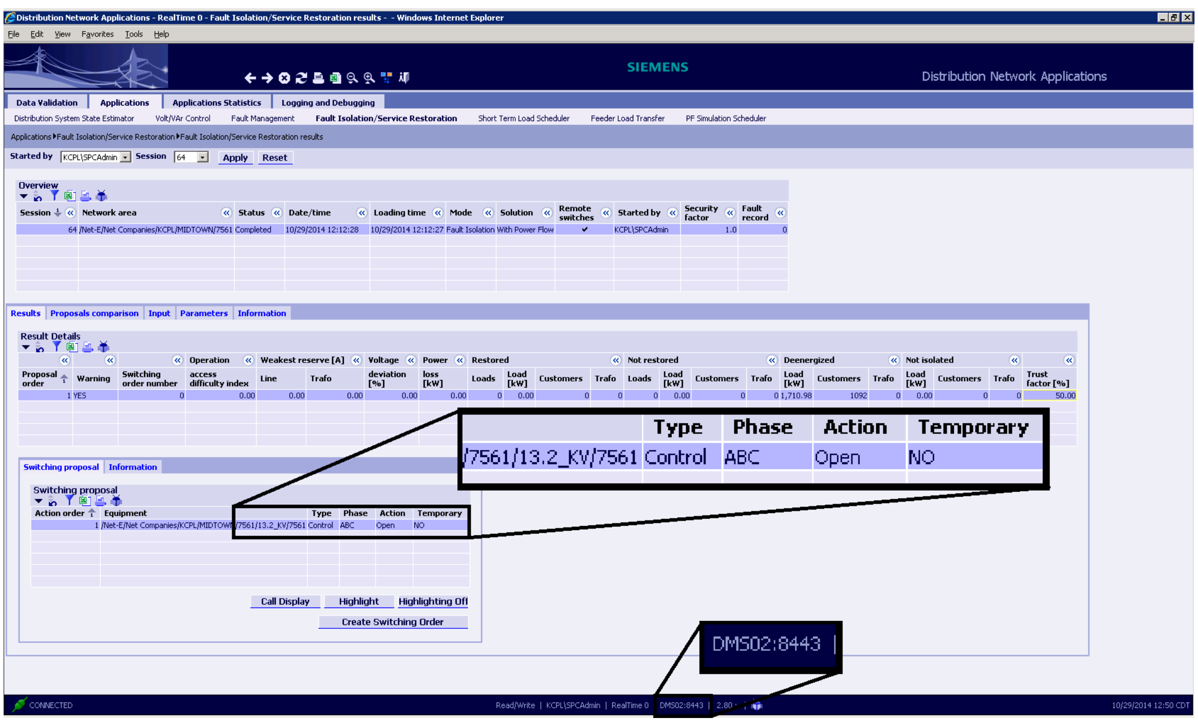
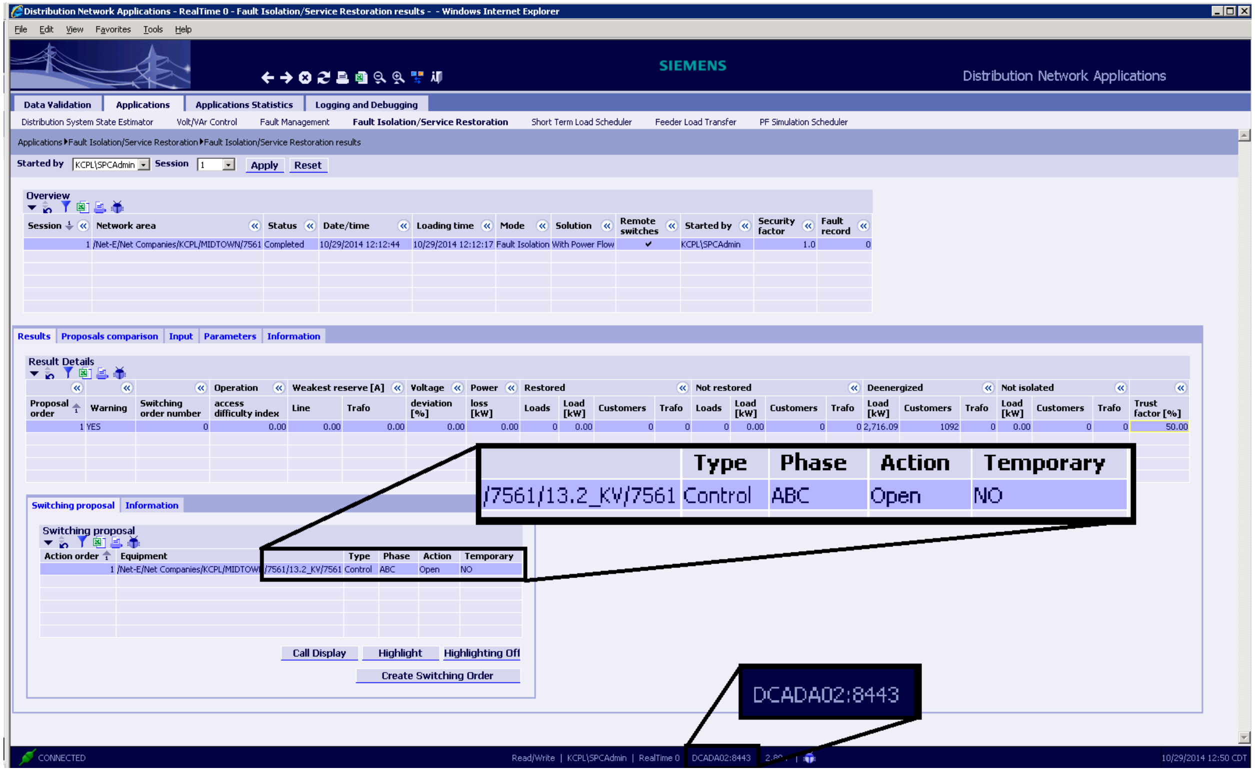


Figure 3-96: FISR via the DCADA



3.4.5.3.2.4 Handling the Hierarchical Control

For much of KCP&L's testing and operational use, the first responder applications were run at the DMS level. Since there was only one substation with local control (Midtown), running the system at the DMS level was very similar to how it would have been run at the DCADA level. However, managing the control between these systems remains important. This would have been even more critical if KCP&L had implemented one DMS and multiple DCADA systems.

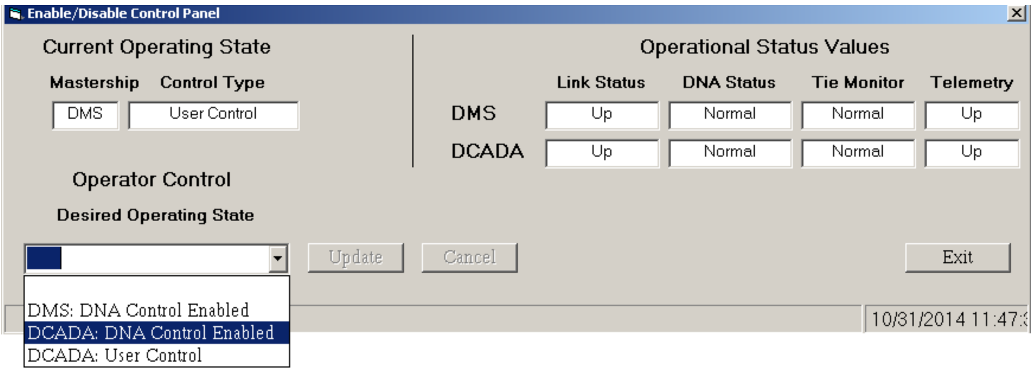
In general, the operator can operate any device from the DMS GUI. If the operator puts any application in closed loop from the DMS, then the respective application would control that device, but the operator still retains ultimate control of that device, and therefore could override, if necessary, any changes made by the application. So if an application closed a breaker, the operator could go and open it from the GUI immediately afterwards.

The DCADA functions a bit differently by design. The intent of the DCADA is that it is fully automated, and once control is transferred the operator doesn't have control capabilities on top of the applications. In KCP&L's implementation, however, if the operator assigns control to DCADA, then the operator can still control the device. This modification from the original design was done so that KCP&L could practice running the system from the DCADA in a safer environment.

When control is transferred between the DMS and DCADA, control over all applications switches. So half of the First Responder applications could not be running in closed loop from the DMS while the other half are running in closed loop from the DCADA.

Figure 3-97 below shows the screen where the operator can switch between DMS and DCADA control. For either system, the operator can select between two modes of operation: 1) User Control, where devices are only operated when the user makes a modification; or 2) DNA Control Enabled, where First Responder applications control the devices. When the DNA Control Enabled is activated, the user can still control devices on top of the applications. By design, the DCADA system wasn't intended to allow for User Control mode; rather, the DCADA was intended to be a black box where the system ran completely on its own with no user intervention. The trust required to run the DCADA this way would take a long time to develop, however, so Siemens allowed the DCADA to operate with user input, similar to the DMS.

Figure 3-97: Control Toggle Between DMS and DCADA



3.4.5.3.2.5 Issues and Corrective Actions

The following issues and corrective action were encountered during the performance of the Substation Hierarchical Control operational demonstration and analysis.

Table 3-65: Issues and Corrective Actions

Issue	Corrective Action
• SICAM could not handle the quantity of data from substation and field devices.	• The team modified device deadbands so that reporting wouldn't occur so frequently. When overload problems persisted, the SICAM hardware was replaced with a more robust solution.
• Operator lack of comfort with running system in closed loop.	• Since operators were not comfortable running the applications in a closed loop mode from neither the DMS nor the DCADA, KCP&L ran the applications in an open loop mode from the DMS for the majority of the operational testing period.
• Operators concerned about unintentionally running FLT and FISR while running other applications in closed loop mode.	• As a precaution against unintentional closed loop operation, KCP&L disabled FLT and FISR from the System Management tool. This prevented accidental activation of these applications when an operator was running VVC, for example, in closed loop mode.

3.4.5.3.3 Findings

The results obtained in the execution and analyses of the Substation Hierarchical Control operational demonstration are summarized in the sections below.

3.4.5.3.3.1 Discussion

KCP&L's SGDP has provided significant education regarding pros and cons of a distributed hierarchical control system.

Upon project initiation, KCP&L took a crawl, walk, run approach to system control. The plan was to crawl first — by running the applications from the DMS in an open loop mode. Next, KCP&L planned to walk — by running the applications from the DMS in a closed loop mode. Finally, KCP&L planned to run — by running the applications from the DCADA in a closed loop mode. As the project progressed, the operators lacked enough comfort with the systems to really operate much in the walk and run phases; rather, they preferred to operate the applications primarily from open loop mode in the DMS.

Although the applications weren't run frequently in closed loop mode from either the DMS or the DCADA, KCP&L did perform testing from both systems to confirm that each first responder application yielded the same results, regardless of whether it was run from the DMS or the DCADA.

Although the SICAM was problematic at first — due to excessive data and the imperfect nature of the wireless field device communications — it proved to work well in the end. It functioned as a traffic cop, sending and receiving data from a variety of systems.

Lastly, the HMI worked well and provided a comprehensive view of the substation operations. This GUI also improved safety for substation operations by allowing technicians to operate devices from inside the substation control house.

3.4.5.3.3.2 Expectations vs. Actuals

The following table provides a comparison of the Expected Results and the Actual Outcomes for the Substation Hierarchical Control operational demonstration.

Table 3-66: Expected Results vs. Actual Outcome

Expected Results	Actual Outcome
• Evaluation of existing control system technologies to implement a distributed hierarchical control system will provide experience and learning for the industry.	• KCP&L gained significant experience through the implementation of its distributed hierarchical control system. KCP&L has shared experiences with the industry through papers and conference presentations.
• Remote monitoring and operation of all substation equipment from a single location within the substation will provide an increased level of safety for the field operator.	• By allowing the field operator to control substation devices from a single location, KCP&L prevents the operator from manual operation at the device itself. This minimizes risk of accident to the operator.

3.4.5.3.3.3 Computational Tool Factors

This demonstration did not produce any inputs to the Smart Grid Computational Tool benefits analysis.

3.4.5.3.4 Lessons Learned

Throughout the demonstration of the Substation Hierarchical Control function, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- For a data concentrator such as the SICAM, careful attention needs to be given to see that the system can handle RF communications. Many data concentrators on the market were designed for hardwired connections, and they don't respond well to field networks with intermittent communications.

- For future deployments, analysis regarding expected data volumes should be performed prior to implementation. This is important, to confirm that the hardware is capable of handling all of the data going into and out of the data concentrator.
- For KCP&L's implementation, the SICAM was used almost purely as a traffic cop — directing inbound and outbound data. The SICAM is also capable of performing computations, however. These calculations would normally be done in a SCADA system. If these calculations aren't done at the SICAM, then every downstream system would need to do these same calculations. By performing the calculations outside of the SICAM, KCP&L was forced to verify that all those downstream systems were doing the calculations in exactly the same manner. For future implementations, doing the calculations at the SICAM (or other data concentrator) would make the most sense.
- The HMI for KCP&L's project was built like a traditional SCADA system, so there isn't an easy way to maintain it. For example, if a relay was added at the substation, the entire HMI would need to be rebuilt — the diagram would need to be modified, the points would have to be added, etc. This issue was not relevant for the DCADA model, which propagates from DMS.
- Management of hierarchical control systems is currently lacking in the industry. Most systems have been built with each serving as the sole control authority, so when multiple systems are sharing this authority there needs to be an overarching controller that grants authority.
- Throughout the deployment and use of these systems, KCP&L discovered several main gaps in the functionality of the Siemens applications. As these were discovered, KCP&L worked with Siemens to develop workarounds.
    - The area of implementation for applications was not granular enough. Siemens applications could only be run on an injection point (transformer). Ideally, these applications could be run on the entire service territory, substation, transformer, bus, or feeder. For example, if a certain feeder is suitable for CVR — but not all the feeders from that transformer are — the user would have to run CVR on all the feeders from that transformer.
    - The settings for an application applied across the entire system, and could not be configured differently for different areas. For example, KCP&L could not set different VVC voltage limits for different feeders.
    - When one application was changed to closed loop, all the other applications were also forced to run in closed loop. KCP&L wanted to be able to run different applications from different modes of operation.
    - KCP&L discovered that closed loop cannot be enabled at both the DCADA and DMS at the same time. Only one system can be in closed loop at a given time. For example, VVC can't be run in closed loop from the DCADA while FLT is run in closed loop from the DMS.
- As KCP&L discovered throughout the implementation of the project's distributed hierarchical control systems, many of the biggest challenges were not technical challenges. There were significant change management and cultural issues to address before the organization would be comfortable with localized, autonomous controllers. Significant training and time would be required in order for personnel and the utility to gain trust with the system prior to moving to a closed loop mode.

3.4.6 Real Time Load Measurement & Management

This function provides real-time measurement of customer consumption and management of load through AMI systems (smart meters, two-way communications), and embedded appliance controllers that help customers make informed energy use decisions via real-time price signals, time-of-use (TOU) rates, and service options.

3.4.6.1 Automated Meter Reading

Automated Meter Reading is a demonstration of one aspect of the Real Time Load Measurement & Management function.

3.4.6.1.1 Overview

The following sections provide an overview of the operational, demonstration, testing, and evaluation methodology used for the Automated Meter Reading operational demonstration.

3.4.6.1.1.1 Description

AMI was deployed to the entire KCP&L SmartGrid Demonstration area. Deployment included the installation of smart meters (capable of two-way communications, interval metering, and remote connect/disconnect) for approximately 14,000 residential, commercial, and industrial customers. Meters measure, store, and wirelessly transmit 15-minute interval energy usage data to a central MDM system where it was available to other KCP&L systems. Communications between meters and the MDM was accomplished through a dedicated RF-mesh Field Area Network (FAN) and KCP&L's private Wide Area Network (WAN).

3.4.6.1.1.2 Expected Results

This operational demonstration of the AMI was expected to yield the following:

- AMI would capture meter reading at 15-minute intervals as opposed to the daily reads accomplished by KCP&L's legacy AMR system.
- AMI would provide the interval metering and communication infrastructure required for many of the SGDP applications.
- AMI would demonstrate improved operational performance over the legacy AMR system, including the reporting of alarms/alerts indicating possible operational issues.

3.4.6.1.1.3 Benefit Analysis Method/Factors

The DOE SGCT was used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits were quantified.

- Reduced Meter Reading Costs
- Reduced Electricity Theft
- Reduced CO_2 Emissions

Benefits were calculated using SGCT formulas. The following factors were measured, projected, or calculated during the application operation and/or demonstration.

Reduced Meter Reading Costs

- Avoided Meter Operations Costs ($) (FSP labor performing on-demand Meter Reads)

Reduced Electricity Theft

- Number of Meter Tamper Detections (#) by customer class

Reduced CO_2 Emissions

- Number of Meter Reading Truck Rolls (avoided)

3.4.6.1.1.4 Testing Methodology

The following points provide an overview of how the operational demonstration and testing for this application was accomplished:

- AMI interval metering was deployed in late 2010 to replace legacy AMR meters for all customers within the SGDP area.
- AMI meter reading performance metrics were captured by the AHE.
- AMR daily read performance metrics were captured by the legacy CIS system.
- AMI meter reads were processed by the AMI Head-End and sent to the MDM and DMAT for bill processing, analysis, reporting, and archival.
- AMI meter events were processed by the AMI Head-End and sent to the MDM for analysis, reporting, and archival.
- The AMI was operated in support of this and other operational demonstrations for nearly four years.

3.4.6.1.1.5 Analytical Methodology

The following points provide an overview of the analytical methods that were used to evaluate the impact and benefits of this application:

- AMI interval load data for all customers within the Project area was extracted for analysis from the MDM System through KCP&L's DMAT.
- The built-in functionality of the DMAT was used to aggregate the 15-minute interval data to hourly interval data aggregated by customer class, then exported to Excel for reporting and analysis.
- AMI meter events for all meters within the Project area were extracted for analysis from the MDM System through KCP&L's DMAT.
- Daily Meter Read Performance statistics were extracted from the AHE and CIS systems.

3.4.6.1.2 Plan Execution and Analysis

The following sections provide details regarding the functional tests performed, data collected, and analysis performed for the Automated Meter Reading operational demonstration.

3.4.6.1.2.1 Daily Meter Read Performance

The KCP&L project team tracked and reported the AMI Daily Read Performance on each of the semiannual metrics reporting. Table 3-67 shows the AMI meter performance metrics that have been reported and shows that over the course of the SGDP, the AMI network has established a Daily Read Performance above 99% for the past year.

Table 3-67: AMI Meter Performance Impact Metrics

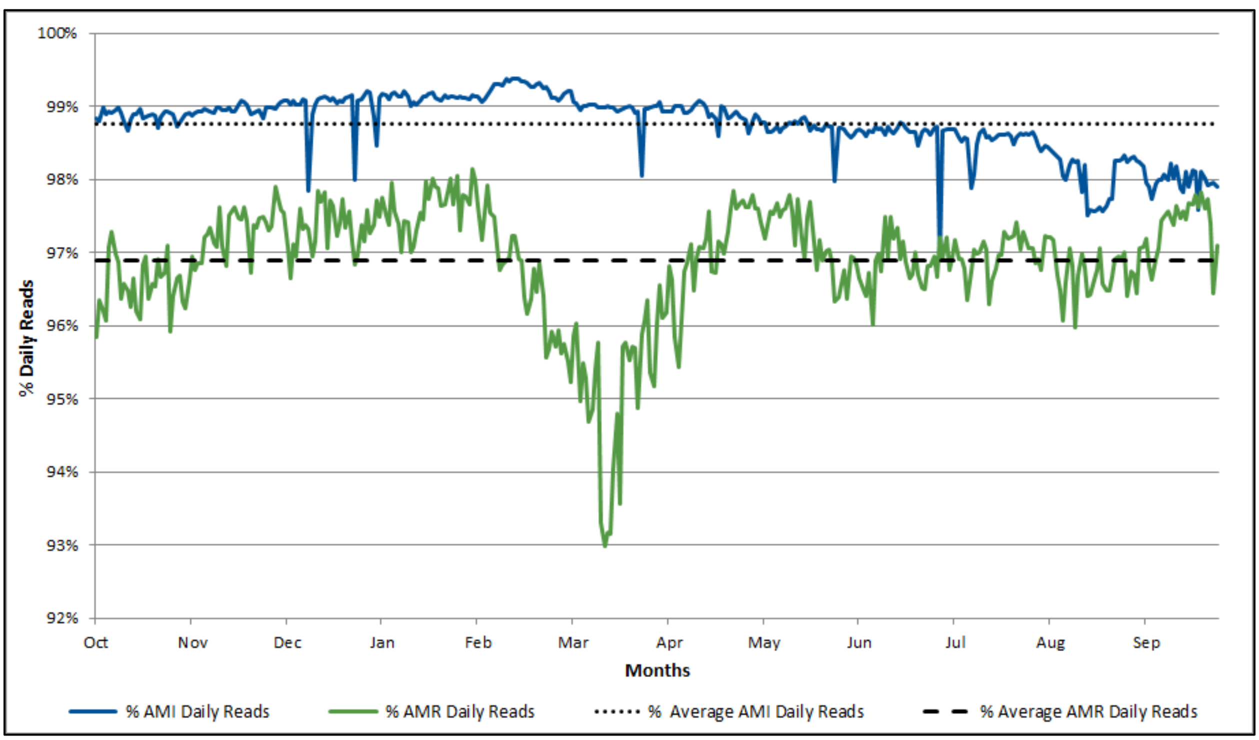
Period	Meter Data Completeness	Daily Read Performance
Winter 2013	99.01%	99.14%
Summer 2014	99.27%	99.22%

KCP&L currently has a legacy AMR system covering 500,000 meters in metropolitan Kansas City. One of the objectives of this operational test was to demonstrate that the AMI system would provide improved meter reading performance over the legacy AMR system. In performing this analysis the project team analyzed the daily read performance statistics from the ARM and AMI systems. These daily performance statistics are presented in Figure 3-98, below, showing that the AMI system provides more consistent performance and, on average, performs 2 percentage points better than the AMR system.

Upon initial inspection of the graph, questions arose concerning the apparent decrease in performance of the AMI system during the last half of the year. The AMI daily read statistics had consistently been reported at over 99% and they appeared to be trending down to 98% in August and September. Upon closer inspection of the data, the AMI performance maintained the daily read performance until May 2014, at which time it started decreasing. What happened? KCP&L had begun its enterprise AMI deployment.

KCP&L began the enterprise deployment of AMI technology by slowly replacing AMR meters in early 2014. By June, KCP&L had begun a more aggressive AMR replacement rate and targeted areas where AMR performance had historically been very poor. Two things happened that are visually apparent in the graphs. First, the AMI read performance suffered initially because the network was less stable during build out and, since the enterprise deployment far exceeded the stable SmartGrid AMI meter counts (14,000), the average performance suffered. Secondly, since the focus was on replacing AMR meter in poor performance areas, the AMR daily read performance noticeably improved.

Figure 3-98: AMR and AMI Daily Read Performance



3.4.6.1.2.2 Meter Interval Usage Data Completeness

The KCP&L project team analyzed the AMI interval data collected by the MDM over the last year of demonstration system operations. Table 3-68 summarizes AMI interval data metrics calculated and shows that while 99.96% of all interval data was collected; 98% of meters had complete interval data for the entire year and only 0.09% of the "meter days" had incomplete data.

Table 3-68: AMI Interval Data Metrics

Metric	Oct 2013	Nov 2013	Dec 2013	Jan 2014	Feb 2014	Mar 2014	Apr 2014	May 2014	June 2014	July 2014	Aug 2014	Sept 2014	12 Month Average
Active Meters	13,113	13,208	13,259	13,346	13,348	13,354	13,271	13,238	13,151	13,145	13,019	13,013	13,205
Meters with 100% reads	12,884	12,796	12,985	13,050	12,900	13,175	13,209	13,035	13,004	12,949	12,500	12,860	12,946
Meters with 100% reads (%)	98.25%	96.88%	97.93%	97.78%	96.64%	98.66%	99.53%	98.47%	98.88%	98.51%	96.01%	98.82%	98.03%
Meter Days	404,001	392,416	409,758	412,556	373,354	413,106	399,123	409,037	393,452	404,812	403,289	390,638	400,462
Meter Days with 100% reads	403,747	391,869	409,465	412,175	372,843	412,909	399,058	408,829	393,193	404,480	401,978	390,431	400,081
Meter Days with 100% reads (%)	99.94%	99.86%	99.93%	99.91%	99.86%	99.95%	99.98%	99.95%	99.93%	99.92%	99.67%	99.95%	99.91%
Meter Days with < 100% reads	254	547	293	381	511	197	65	208	259	332	1,311	207	380
Meter days with < 100% reads (%)	0.06%	0.14%	0.07%	0.09%	0.14%	0.05%	0.02%	0.05%	0.07%	0.08%	0.33%	0.05%	0.09%
Average Missing Intervals	55	52	49	53	70	75*	38	24	45	44	48	43	50
Average Interval Data Collected (%)	99.97%	99.94%	99.96%	99.96%	99.96%	99.98%	99.99%	99.96%	99.97%	99.96%	99.84%	99.97%	99.96%

1.1.1.1.5.1 Hourly Usage Profile by Rate Class

The KCP&L project team used the built-in functionality of the DMAT to aggregate the 15-minute interval data to hourly interval data aggregated by customer class, then exported to Excel for inclusion in semiannual metrics reporting. Figure 3-99 depicts the final metric data reported for the SmartGrid Residential rate class. Figure 3-100 depicts the Residential rate class load profile for the 2014 system peak day, which occurred August 25.

Figure 3-99: SmartGrid Residential Rate Class Load Profile (April – September 2014)

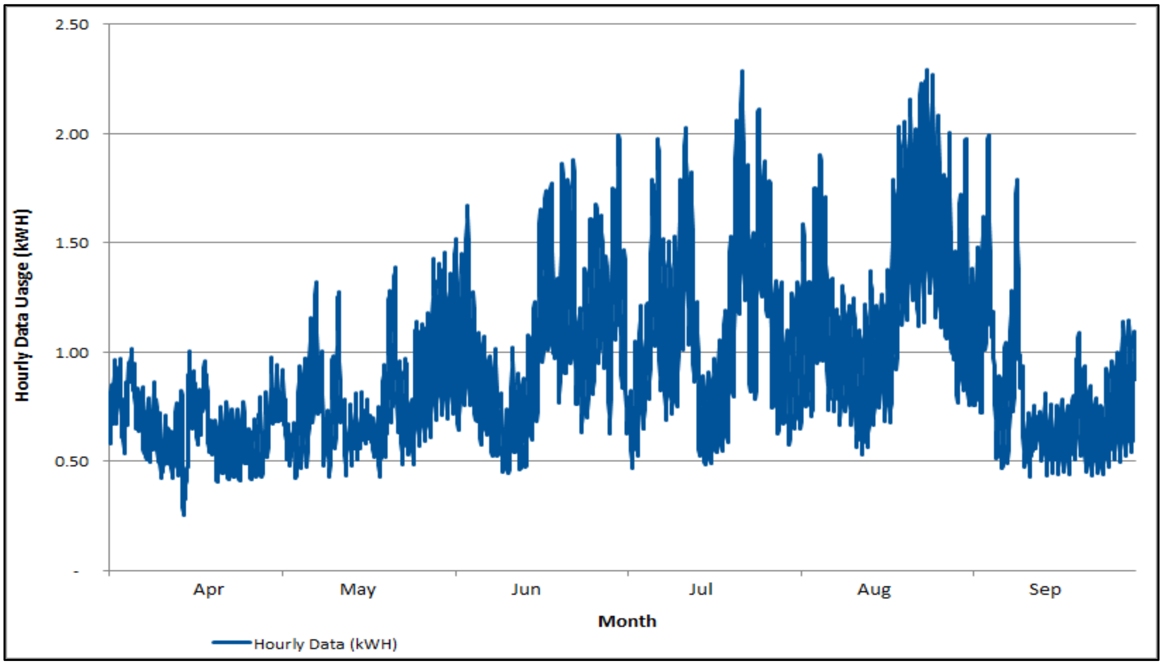


Figure 3-100: SmartGrid Residential Rate Class Peak Day Load Profile

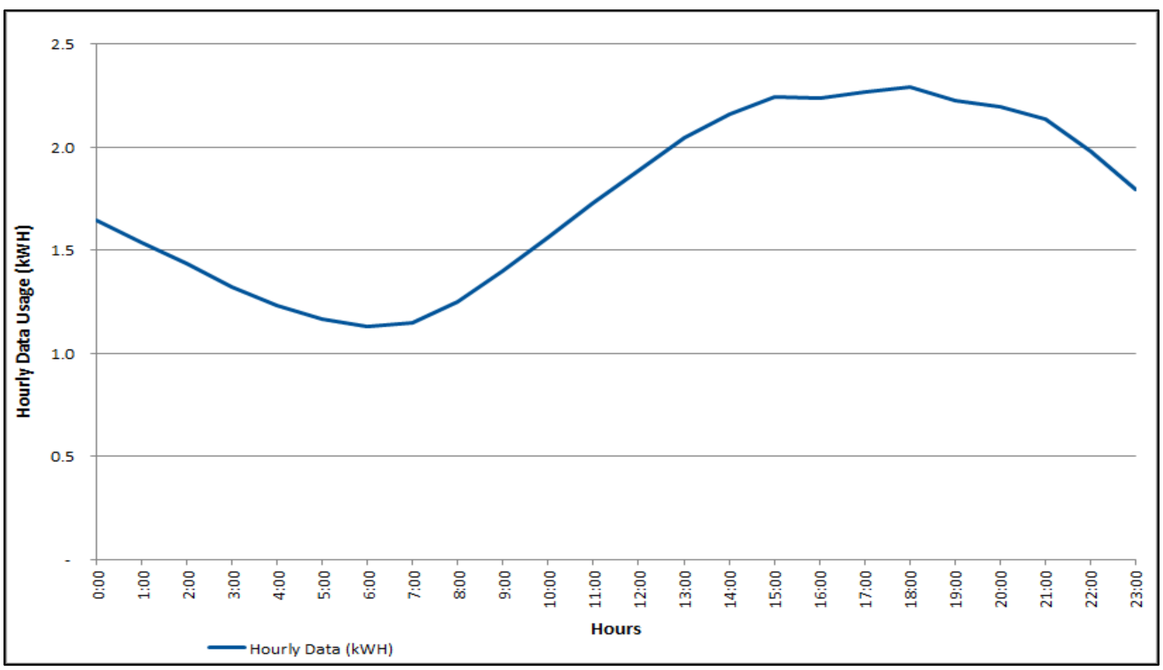


Figure 3-101 below depicts the final metric data reported for the SmartGrid Commercial rate class and Figure 3-102 depicts the Commercial rate class load profile for the 2014 system peak day which occurred August 25.

Figure 3-101: SmartGrid Commercial Rate Class Load Profile (April – September 2014)

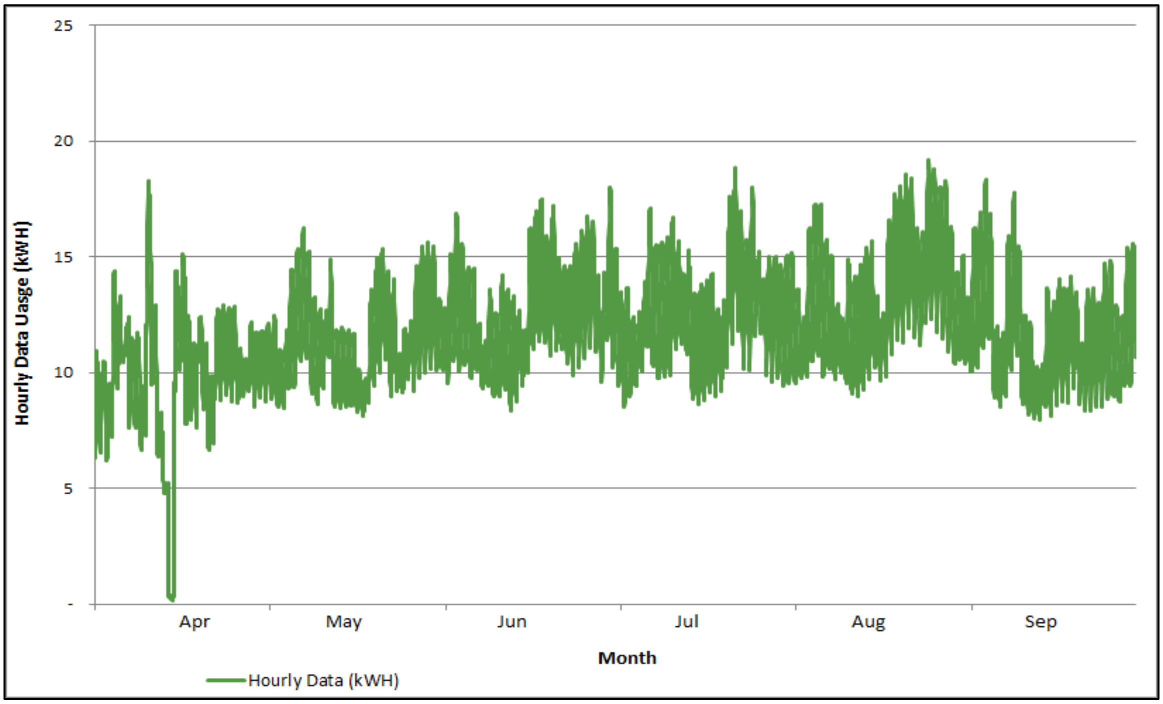
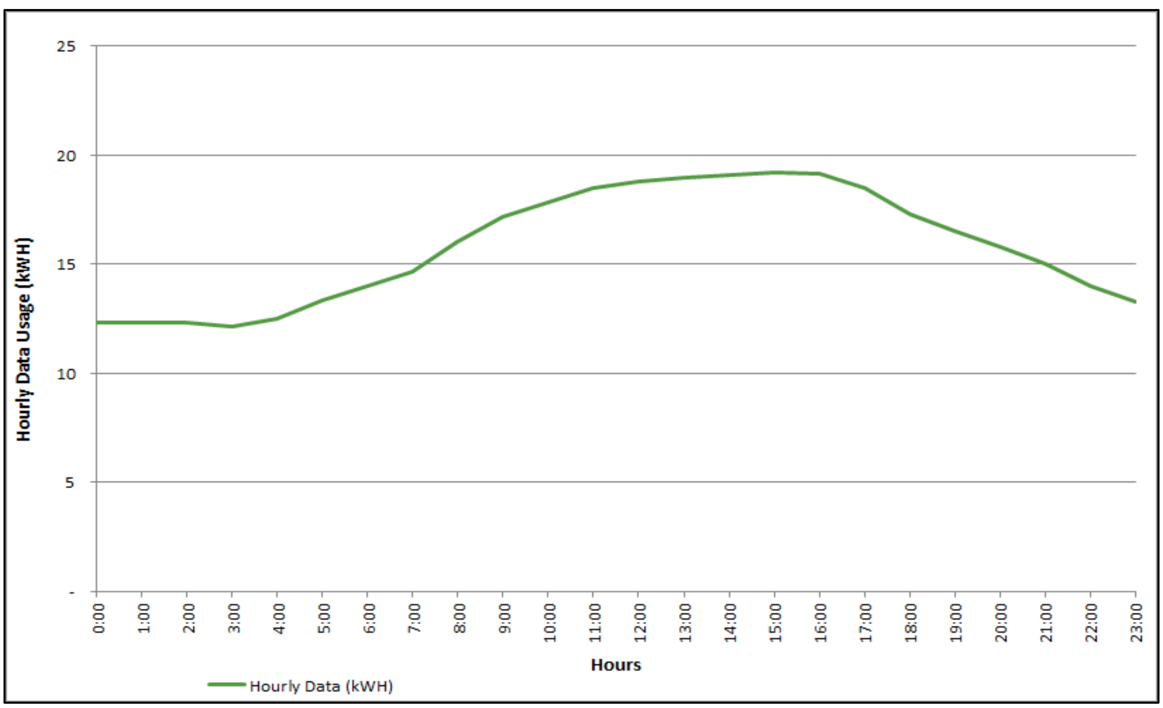


Figure 3-102: SmartGrid Commercial Rate Class Peak Day Load Profile



3.4.6.1.2.3 Meter Event Analysis

SmartMeters and AMI infrastructure devices can be programmed to provide a vast number of event notifications, alerts, and alarms. Generally these event notifications can be classified in one or more of the following areas:

- Meter Malfunction
- Meter Update/Operation Confirmation
- Meter Abnormal Behavior
- AMI Network Malfunction
- AMI Network Update/Operation Confirmations
- Power Outage/Restore
- Tamper Detection

Some of these events may be analyzed and addressed by the AMI infrastructure, but the majority of them are passed on to the MDM for further processing, analysis, and archival. Power Outage and Power Restore events are sent directly to the OMS for outage analysis. Table 3-69 provides a listing of non-outage events that the project team configured to be sent to the MDM for analysis and archival.

Table 3-69: Non-Outage Meter Events from MDM

Event Number	Description
3.18.1.199	RAM Failure Detected
3.18.1.220	ROM Failure Detected
3.2.1.149	Meter Battery Low
3.21.1.173	Non-Volatile Memory Failure Detected
3.21.1.213	Meter Reprogrammed
3.21.1.52	Fatal Error
3.21.1.79	Measurement Error Detected
3.21.1.81	Event Log Cleared
3.21.1.95	History Log Cleared
3.21.18.79	Self Check Error Detected
3.21.7.79	Meter Configuration Error
3.33.1.219	Reverse Rotation Detected
3.33.1.257	Tamper Attempted Suspected
3.8.1.61	Meter Demand Reset Occurred

Not all events require further action by the MDM and can simply be archived. Some, like "Demand Reset," can be used to verify that a requested or required operation occurred. Others, like "Fatal Error," can have validation rules established that automatically trigger a maintenance service order, while still others, like "Tamper Attempted Detected," may need validation and threshold rules established before a Revenue Protection Investigation Order is initiated.

The KCP&L project team analyzed the AMI event data collected by the MDM over the last year of demonstration system operations. Table 3-70 summarizes AMI meter events recorded in the MDM by event type and month. The table includes the number of individual meters responsible for reporting the events. For example 4 meters experienced memory failures and were responsible for generating 181 event reports over a 2 month period until the meters were replaced. Similarly 26 meters reported over 52 thousand reverse rotation events and 19 of those meters also reported 239 suspected tamper events. Upon further analysis, a configuration defect was discovered in the net metering configuration that caused these meters to incorrectly report reverse rotation events. Once those erroneous events were scrubbed from the data, there were only 10 meters that reported tampering and reverse rotation events that were truly suspect tampering situations that needed to be investigated.

Table 3-70: MDM Recorded Meter Events

Meter Events	Meters Reporting Events	Annual Events	2013			2014								
			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept
Event Log Cleared	5	5		2	2					1				
Load Profile Cleared	5	5		2	2					1				
Measurement Error	5	10	1								9			
Memory Failure	4	181								1	180			
Tamper	19	239		30	4	6	14	21	19	46	30	11	50	8
Reverse Rotation	26	52,320	3,555	4,713	5,317	5,091	4,472	4,227	2,990	4,666	4,075	3,653	5,193	4,368
Demand Reset	13,032	210,102	17,106	17,271	17,024	19,371	17,932	18,340	17,588	18,527	17,883	14,055	17,653	17,352

3.4.6.1.2.4 Issues and Corrective Actions

No issues requiring corrective actions were encountered during the performance of the Automated Meter Reading operational demonstration and analysis.

3.4.6.1.3 Findings

The results obtained in the execution and analyses of the Automated Meter Reading operational demonstration are summarized in the sections below.

3.4.6.1.3.1 Discussion

KCP&L currently has a legacy AMR system covering 500,000 meters in metropolitan Kansas City. One of the objectives of this operational test was to demonstrate that the AMI system would provide improved meter-reading performance over the legacy AMR system. The daily performance metrics presented in Figure 3-1 show that the AMI system established a 99% daily read performance metric and provided a more consistent performance throughout the year and, on average, performed 2 percentage points better than the AMR system.

The improvement of 2 percentage points in daily reads means that every month there are 280 fewer accounts in the SmartGrid Demonstration area that will require extra processing during the bill calculation. Special handling may include: initiation of an automated AMI on-demand read; initiation of a truck roll to obtain the billing read; or issuance of an estimated bill.

The AMI infrastructure also significantly outperformed the legacy AMR system for completeness of interval data. With more than 30 days of reads and interval usage data stored on the AMI meter and the gap-filling data retrieval functions of the AMI head-end, the actual data capture is significantly improved, providing 99.96% of interval usage data from functioning meters. With the one-way AMR technology, if a read was not received it was lost.

SmartMeters and AMI infrastructure devices can be programmed to provide a vast number of event notifications, alerts, and alarms. Some of these events may be analyzed and addressed by the AMI, but the majority of them will be passed on to the MDM for further processing, analysis, and archival. Power Outage and Power Restore events will be sent directly to the OMS for outage analysis. Not all events require further action by the MDM and can simply be archived. Some, like “Demand Reset,” can be used to verify that a requested or required operation occurred. Others, like “Fatal Error,” can have validation rules established that automatically trigger a maintenance service order. Still others, like “Tamper Attempted Detected,” may need validation and threshold rules established before a Revenue Protection Investigation Order is initiated.

3.4.6.1.3.2 Expectations vs. Actuals

The following table provides a comparison of the Expected Results and the Actual Outcomes for the Automated Meter Reading operational demonstration.

Table 3-71: Expected Results vs. Actual Outcome

Expected Results	Actual Outcome
• AMI will capture meter reading at 15-minute intervals as opposed to the daily reads currently accomplished by KCP&L's legacy AMR system.	• AMI captured 15-minute interval usage data from all meters and improved the daily meter read success rate over the legacy AMR system.
• AMI will provide the interval metering and communication infrastructure required for many of the SGDP applications.	• AMI supported numerous project reporting and analysis requirements and provided the communications infrastructure for most of the SmartEnd-Use components and functions.
• AMI will demonstrate improved operational performance over the legacy AMR system, including the reporting of alarms/alerts indicating possible operational issues.	• AMI significantly improved the notification rate for outages and provided restoration messages. AMI also added meter events such as meter tampering.

3.4.6.1.3.3 Computational Tool Factors

The following table lists the values derived from the Automated Meter Reading operational demonstration that will be used as inputs to the SmartGrid Computational Tool.

Table 3-72: Computational Tool Values

Name	Description	Calculated Value
(Reduced) Meter Operations Cost	Total cost associated with meter operations costs.	\$63,380
Number of Meter Tamper Detections - Residential	Total annual number of residential meter tamper cases detected and substantiated as legitimate theft attempts.	10
(Avoided) Number of Meter Reading Truck Rolls	Total (reduced) number of manual meter reads performed per year.	3,169

- <u>(Avoided) Number of Meter Reading Truck Rolls</u> – Based on AMI providing improved daily meter reads, thus requiring fewer monthly check reads. This value is calculated as follows:

Active AMI Meters (#/mo) x 12 mo. x Improvement in Daily Register Reads (%)
13,205 x 12 x 2% = 3,169

- <u>Reduced Meter Operations Cost</u> – Based on AMI providing improved daily meter reads and, requiring fewer monthly check reads. This value is calculated as follows:

(Avoided) Number of Meter Reading Truck Rolls (#) x Cost per Meter Reading Order (\$/Order)
3,169 orders x \$20.00/order = \$63,380

3.4.6.1.4 Lessons Learned

Throughout the conduct of the operational testing and analysis of the Automated Meter Reading function, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- Numerous lessons learned regarding the deployment of AMI technology were identified and are outlined Section 2.2.1.1.4 of this report. Key among them was the realization that routine AMI system and meter firmware upgrades will be a way of life for enterprise AMI deployments. This was not the case for KCP&L's legacy AMR system.
- The daily performance of the AMI infrastructure significantly outperformed the legacy AMR system by establishing a consistent 99% daily read performance metric. With more than 30 days of reads and interval usage data stored on the meter and the gap-filling data retrieval functions of the AMI head-end, the actual data capture is significantly improved, providing nearly 100% of meter data from functioning meters.
- Establishing the validation and processing rules for non-outage meter events will be a significant effort during an enterprise Smart Meter deployment. A variety of non-outage-related meter events are passed to the MDM. Not all events require further action and can simply be archived. Some, like "Demand Reset," can be used to verify that a requested or required operation occurred. Others, like "Fatal Error," can have validation rules established that automatically trigger a maintenance service order. Still others, like "Tamper Attempted Detected," may need validation and threshold rules established before a Revenue Protection Investigation Order is initiated.

3.4.6.2 Remote Meter Disconnect/Reconnect

Remote Meter Disconnect/Reconnect is a demonstration of one aspect of the Real Time Load Measurement & Management function.

3.4.6.2.1 Overview

The following sections provide an overview of the operational, demonstration, testing, and evaluation methodology used for the Remote Meter Disconnect/Reconnect operational demonstration.

3.4.6.2.1.1 Description

AMI was deployed to the entire KCP&L SmartGrid Demonstration area, approximately 14,000 residential and commercial customers. Nearly all of the AMI meters have an integral switch capable of remote connect/disconnect capabilities. Integration between CIS, MDM, and the AMI was implemented to automate remote connect/disconnect functionality to support customer requested connect/disconnect orders. Remote connect/disconnects for nonpayment were not implemented, due to current Public Service Commission requirements for the utility to attempt in-person contact prior to disconnect for nonpayment.

3.4.6.2.1.2 Expected Results

This operational demonstration of the AMI was expected to yield the following:

- AMI two-way communications would enable KCP&L to remotely connect or disconnect customers from the KCP&L service center.
- Truck rolls and Field Service Professional labor would be avoided for each remote connect/disconnect operation.

3.4.6.2.1.3 Benefit Analysis Method/Factors

The DOE SGCT was used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits were quantified.

- Reduced Meter Reading Costs
- Reduced CO_2 Emissions

Benefits were calculated using SGCT formulas. The following factors were measured, projected, or calculated during the application operation and/or demonstration.

Reduced Meter Reading Costs

- Avoided Meter Operations Costs ($) (FSP labor performing Connect/Disconnects)

Reduced CO_2 Emissions

- Number of Meter Reading Truck Rolls (avoided)

3.4.6.2.1.4 Testing Methodology

The following points provide an overview of how the operational demonstration and testing for this application was accomplished:

- AMI meters were deployed in late 2010 to replace legacy AMR meters for all customers within the SGDP area.
- Integration between CIS, MDM, and the AMI Head End was implemented to automate the remote service order (connect/disconnect) processes.
- Remote connect/disconnect performance metrics tracking was captured by the CIS service order subsystem.

3.4.6.2.1.5 Analytical Methodology

The following points provide an overview of the analytical methods that were used to evaluate the impact and benefits of this application:

- Avoided truck rolls were determined based on the number of successful remote connect and disconnect operations performed.

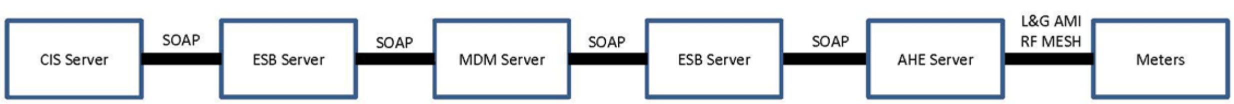
3.4.6.2.2 Plan Execution and Analysis

The following sections provide details regarding the functional tests performed, data collected, and analysis performed for the Remote Meter Disconnect/Reconnect operational demonstration.

3.4.6.2.2.1 Demonstration Overview

The systems integration implemented to support the remote disconnect/reconnect function is illustrated in Figure 3-103.

Figure 3-103: Systems Integration Supporting Remote Disconnect/Reconnect



3.4.6.2.2.2 Remote Disconnect/Reconnect Operational Statistics

For the analysis of this function, remote disconnect/reconnect operations were recorded by the CIS service order subsystem. Figure 3-104 below shows the monthly remote service orders processed for the SmartGrid Demonstration Area.

Figure 3-104: Monthly Remote Service Orders Processed

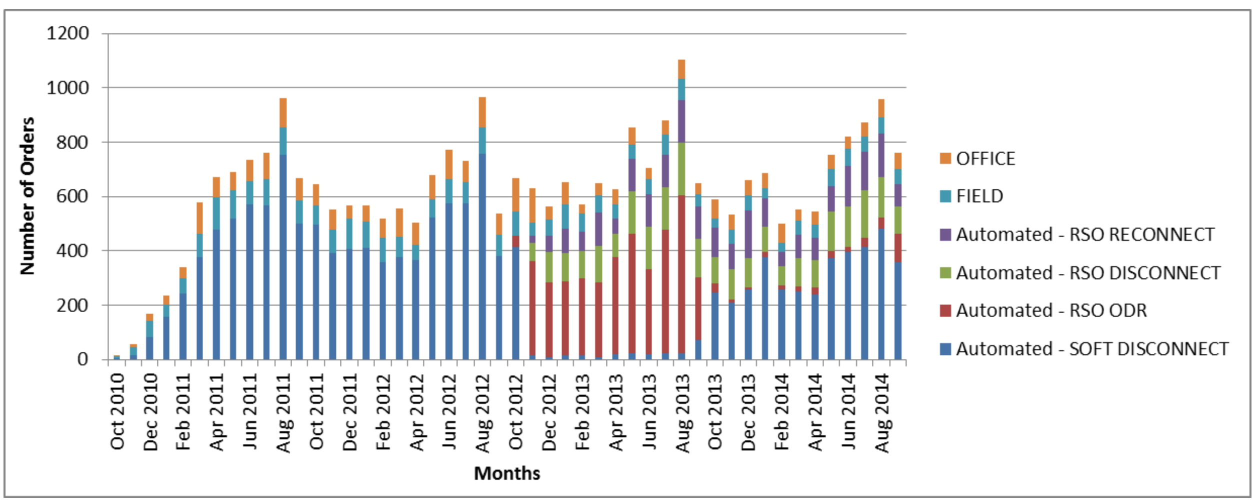


Table 3-73 shows the monthly remote service orders processed and the corresponding truck rolls avoided over two year operational period.

Table 3-73: Remote Disconnect/Reconnect Metrics

Period	Successful Disconnects	Successful Reconnects	Truck Rolls Avoided
Winter 2012	518	369	887
Summer 2013	889	692	1,581
Winter 2013	581	622	1,203
Summer 2014	817	715	1,532
Total	2,805	2,398	5,203

3.4.6.2.2.3 RSO Soft Disconnects

With implementation of the legacy AMR system in the mid-1990s KCP&L began using a "soft disconnect" process in lieu of a physical disconnect/reconnect for many customer-initiated turn-on/off service orders. The AMR soft disconnect process used the previous day's AMR read as the meter read for a turn-on/off order. This soft disconnect process worked well for so-called "buddy orders" and "landlord reverts," in which turn-on/off orders are either processed together or within a relatively short time span. If a premise becomes occupied without a subsequent turn-on order being processed, a "vacant with usage" situation occurs.

At the beginning of the SGDP, the AMI support for soft disconnects was implemented using the AMI midnight read. When the MDM and the remote service order functions were subsequently implemented, the on-demand read function was implemented in conjunction with the connect/disconnect functions. KCP&L then began using the AMI on-demand read function to perform soft disconnects for buddy orders and land lord reverts. The volume of soft disconnects using the AMI midnight read, and the transition to using the on-demand read in November 2012, is illustrated in Figure 3-104.

Using the on-demand read function for these soft disconnects had two unexpected consequences: First, it caused the early-morning batch-processing window for these orders to increase; and, secondly, a higher meter communications failure rate was experienced, due to the higher volume of traffic on the AMI network during the batch window. Any on-demand reads that were not successful had to be manually added to the MWFM routes the following day to obtain a manual read. After further consideration, in September 2013, KCP&L switched the processes back to using the AMI midnight read, and any orders without an available midnight read were automatically included in the daily MWFM order dispatch.

3.4.6.2.2.4 Issues and Corrective Actions

The following issues and corrective actions were encountered during the performance of Remote Meter Disconnect/Reconnect operational demonstration and analysis.

Table 3-74: Issues and Corrective Actions

Issue	Corrective Action
• Commission rules will not allow a disconnect for nonpayment without a visit, which would have required integration with the mobile WMS.	• Since integration with the mobile WMS system was outside of the project scope, company-initiated remote connects/disconnects were not implemented.
• Some connect/disconnect operations were not successful due to integration issues.	• If connect/disconnect was not successful, it was logged into an online error log queue and manually processed by Billing Services.
• RSO Order Failures needed to be identified prior to 6 AM for automated inclusions in MWFM orders.	• Reverted soft connects to using midnight read when available. This also reduced AMI network traffic.

3.4.6.2.3 Findings

The results obtained in the execution and analyses of the Remote Meter Disconnect/Reconnect operational demonstration are summarized in the sections below.

3.4.6.2.3.1 Discussion

The remote disconnect/reconnect function required complex integration of the CIS, MDM, and AMI systems. Not only must the integration successfully process disconnect/reconnect orders, it must coordinate these functions with an on-demand read function. When all aspects of the integration work, the orders process smoothly and disconnects/reconnects are usually executed in under a minute.

The most challenging aspect for project's deployment of remote disconnect/reconnect functions was dealing with all of the unexpected exception handling necessary when some aspect of the integration did not function as designed. Due to the restriction placed on the project to not change CIS and MWFM processes, implementing adequate exception handling processes was not possible and instead a simple online error log queue was developed and manually processed by Billing Services. This experience has provided great insight regarding the types of errors that might occur and the exception-handling processes that must be implemented with an enterprise deployment

Using the on-demand read function to support the soft disconnects orders had several unexpected consequences: First, it caused the early-morning batch-processing window for these orders to increase; and, secondly, a higher meter communications failure rate was experienced, due to the higher volume of traffic on the AMI network during the batch window. Subsequent analysis determined it was more productive to use an on-demand read for these orders only when an AMI midnight read was not available.

3.4.6.2.3.2 Expectations vs. Actuals

The following table provides a comparison of the Expected Results and the Actual Outcomes for the Remote Meter Disconnect/Reconnect operational demonstration.

Table 3-75: Expected Results vs. Actual Outcome

Expected Results	Actual Outcome
• AMI two-way communications will enable KCP&L to remotely connect or disconnect customers from the KCP&L service center.	• Customer-initiated connect/disconnect service orders were implemented. Company-initiated connect/disconnects were not implemented, due to existing commission requirements.
• Truck rolls and Field Service Professional labor will be avoided for each remote connect/disconnect operation.	• Truck rolls were avoided for 5,206 customer-initiated connect/disconnect service orders during the project's two-year operational period.

3.4.6.2.3.3 Computational Tool Factors

The following table lists the values derived from the Remote Meter Disconnect/Reconnect operational demonstration that will be used as inputs to the SmartGrid Computational Tool.

Table 3-76: Computational Tool Values

Name	Description	Calculated Value
(Reduced) Meter Operations Cost	Total cost associated with meter operations costs.	$ 104,120
(Avoided) Meter Reading Truck Rolls	Total (reduced) number of manual meter read (or operations) performed per year.	5,206

- Reduced Meter Operations Cost – Based on AMI providing remote connect/disconnects, this value is calculated as follows:

  (Avoided) Number of Meter Reading Truck Rolls (#) x Cost per Meter Operations Order ($/Order)

  5,206 orders x $20.00/order = $104,120

3.4.6.2.4 Lessons Learned

Throughout the conduct of the operational testing and analysis of the Remote Meter Disconnect/Reconnect function, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- The remote disconnect/reconnect function requires complex integration of the CIS, MDM, and AMI systems. Not only must the integration successfully process disconnect/reconnect orders, they it must coordinate these functions with an on-demand read function. When all aspects of the integration work, the orders process smoothly and disconnects/reconnects are usually executed in under a minute.
- The more difficult aspect for enterprise deployment of remote disconnect/reconnect functions will be designing and implementing all of the necessary exception-handling processes needed when some aspect of the integration does not function as designed. These exception-handling processes will include automated processes that may be as simple as an automated retry; others may require manual intervention to implement the function via the AMI system directly; and, ultimately, an order may have to be routed to the MWFM system for manual execution.

3.4.6.3 Outage Restoration

Outage Restoration is a demonstration of one aspect of the Real Time Load Measurement & Management function.

3.4.6.3.1 Overview

The following sections provide an overview of the operational, demonstration, testing, and evaluation methodology used for the Outage Restoration operational demonstration.

3.4.6.3.1.1 Description

AMI was deployed to the entire KCP&L SmartGrid Demonstration area, approximately 14,000 residential and commercial customers. Meters wirelessly transmitted power outage/restoration alerts via the AMI to a central MDM system, where it was available to the OMS and other KCP&L systems. The MDM and AMI also provided for on-demand verification of meter power status via the two-way communication network.

3.4.6.3.1.2 Expected Results

The operational demonstration of the AMI was expected to yield the following:

- Meter outage/restoration alerts would be transported via the AMI and MDM systems and received and processed by the OMS.
- AMI and MDM would provide the active meter status in response to Power Status Verification requests issued by the OMS.
- While improved outage response should result from this application, this benefit would not be measurable because the SGDP systems would not be used for production outage response.

3.4.6.3.1.3 Benefit Analysis Method/Factors

This Technical Demonstration will not contribute to the project Benefits Analysis. While the AMI outage and restoration alerts were processed by the SmartGrid Demonstration Systems, they were not used for production outage response and therefore no change in SAIDI, SAIFI, and CAIDI could not be measured.

3.4.6.3.1.4 Demonstration Methodology

The following points provide an overview of how the technical demonstration of this application was accomplished:

- AMI meters were deployed in late 2010 to replace legacy AMR meters for all customers within the SGDP area.
- Integration between AMI Head End, MDM, and the OMS was implemented to process power outage/restoration event notifications and power status verification (request/reply) message flows.
- The SGDP DMS-OMS processed and recorded all power outage/restore event notifications for the SGDP area in parallel to the production legacy OMS. The legacy OMS supported all production outage restoration efforts.
- The project team used the DMS-OMS to demonstrate benefits of using the PSV message flow to enhance outage/restoration activities.

3.4.6.3.1.5 Analytical Methodology

The Technical Demonstration of this application does not require any analytical calculations.

3.4.6.3.2 Plan Execution and Analysis

The following sections provide details regarding functional tests performed, data collected, and analysis performed for the Meter Outage Restoration operational demonstration.

3.4.6.3.2.1 Demonstration Overview

The systems integration implemented to support the meter Power Outage/Restoration and Power Status Verification functions are illustrated in the following figures.

Figure 3-105: Systems Integration Supporting Meter Outage Restoration Functions

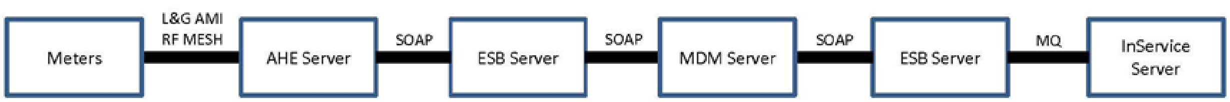
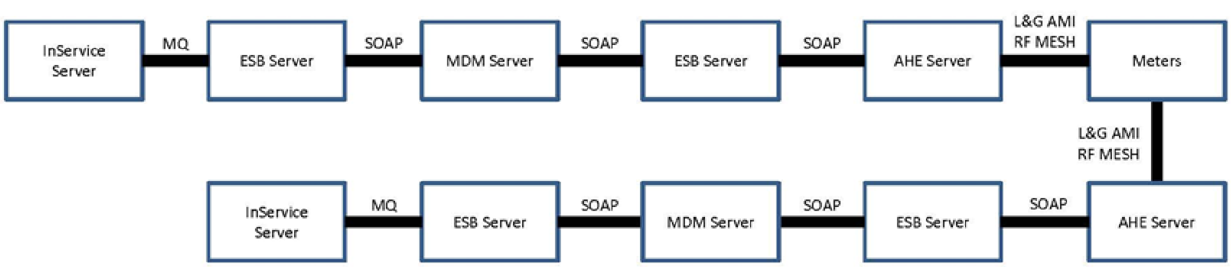


Figure 3-106: Systems Integration Supporting Power Status Verification Functions



3.4.6.3.2.2 Power Outage Alert Performance

The legacy AMR system deployed at KCP&L in the mid-1990s provides a “last gasp” power outage alert. When AMR meters lose power (for both momentary and sustained outages) they immediately and simultaneously broadcast the “last gasp” outage alert, flooding the communications network. Historically, experience has shown that, at best, 25% of the outage alerts are recorded by the AMR network. Due to the nature of the AMR “last gasp”, the OMS has continued to rely primarily on customer calls to initiate a power outage event.

In contrast, the AMI meters wait 30 seconds before broadcasting a power outage alert. This eliminates the majority of power outage alerts due to momentary outages. The AMI meter has enough energy stored to maintain communication for another minute, to see that most outage alerts get routed through the mesh network.

The project team performed an analysis of multiple outage events to determine the performance of the AMI network in delivering a Power Outage alert message for transformer, lateral, and feeder outages. A representative sample of the results of this analysis is presented in the following tables. Generally, for most outage events, Power Outage alerts were received from about 90% of the outaged meters, far exceeding the performance of the legacy AMR “last gasp” communications.

Table 3-77: Outage/Restoration Alert Performance – Transformer Outage

Event Number	Outage Duration	Meters Affected*	Outage Alerts		Restoration Alert	
			Count	Percentage	Count	Percentage
0084389	0:25:04	4	4	100.0%	4	100.0%
0084417	1:43:13	16	16	100.0%	16	100.0%
0084488	0:31:33	9	9	100.0%	9	100.0%
0084564	1:02:58	10	9	90.0%	9	90.0%
0084631	0:20:01	13	11	84.6%	11	84.6%
0084695	0:54:58	8	7	87.5%	7	87.5%
0084762	1:52:34	8	8	100.0%	8	100.0%
0084854	0:56:59	14	11	78.6%	11	78.6%
Total		**82**	**75**	**91.5%**	**75**	**91.5%**

Note: May include meters disconnected for various reasons and were not trackable by the SmartGrid OMS.

Table 3-78: Outage/Restoration Alert Performance – Lateral Outage

Event Number	Outage Duration	Meters Affected*	Outage Alerts		Restoration Alert	
			Count	Percentage	Count	Percentage
0084362	5:48:45	271	264	97.4%	271	100.0%
0084375	1:18:35	15	10	66.7%	11	73.3%
0084391	4:29:20	29	15	51.7%	29	100.0%
0084557	0:34:55	21	20	95.2%	20	95.2%
0084678	4:00:48	111	109	98.2%	111	100.0%
0084691	2:04:58	180	162	90.0%	176	97.8%
0084848	4:12:10	20	20	100.0%	20	100.0%
Total		**647**	**600**	**92.7%**	**638**	**98.6%**

Note: May include meters disconnected for various reasons and not trackable by the SmartGrid OMS.

Table 3-79: Outage/Restoration Alert Performance – Feeder Outage

Event Number	Outage Duration	Meters Affected*	Outage Alerts		Restoration Alert	
			Count	Percentage	Count	Percentage
0084277	0:52:10	2141	1853	86.5%	2079	97.1%
0084444	5:02:03	2106	1929	91.6%	2067	98.1%
0084548	2:30:55	83	77	92.8%	78	93.9%
0084565	10:25:10	2141	2010	93.9%	2141	100.0%
0084776	1:41:39	2044	1617	79.1%	1666	81.5%
Total		**8515**	**7486**	**87.9%**	**8031**	**94.3%**

Note: May include meters disconnected for various reasons and not trackable by the SmartGrid OMS.

3.4.6.3.2.3 Power Restoration Alert Performance

With the legacy AMR system deployed at KCP&L, Power Up notifications by the AMR system could only be sent to the OMS after the AMR system started receiving the periodic meter reads from the meter and AMR network. Historically, experience has shown these AMR Power Up messages were very unpredictable and could take up to an hour to get to the OMS. As a result, KCP&L never incorporated AMR Power Up messages into the legacy OMS outage processing. Instead, the legacy OMS initiates a meter "ping" process 15 minutes after the outage event is closed. The meter's ping request communicates with the AMR field MCC to see if it has received a recent reading from the meter.

In contrast, when power is restored to AMI meters, the meter starts an internal timer that is used to calculate the restore time once network communications are reestablished and network time is restored in the meter. The meter sends a first Power Restoration alert when the meter time is reestablished. A second Power Restoration alert is sent 5 minutes later as a precaution, in case the network backhaul was not fully established when the first message was broadcast. The majority of Power Restoration alerts have typically been received by the AMI system within 5 minutes of the actual power restoration, and nearly all have been received within 15 minutes.

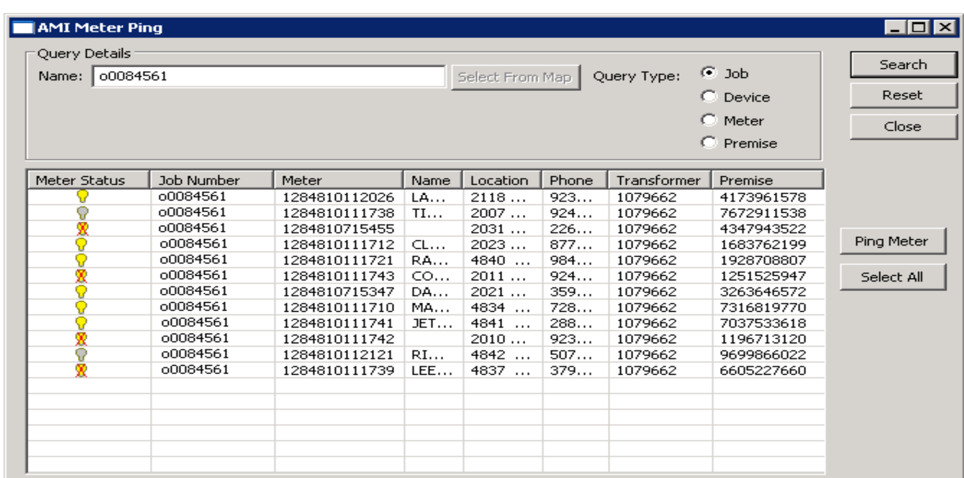
The previous tables show that for most outage events, Power Restoration alerts were received on average from more than 95% of all outaged meters. The timely reporting of such a high percentage of unsolicited Power Restoration alerts significantly improves the OMS Outage Event verification process, minimizing the number of meters from which the OMS must request a Power Status Verification.

3.4.6.3.2.4 Power Status Verification Process

The Power Status Verification functionality can be implemented to support numerous business functions. KCP&L has long used the meter ping with the utility's legacy AMR system to verify customer reported "lights out" calls prior to rolling a truck. Historically, approximately 30 percent of lights out calls end up being "OK on arrival," with the problem being with the customer's equipment.

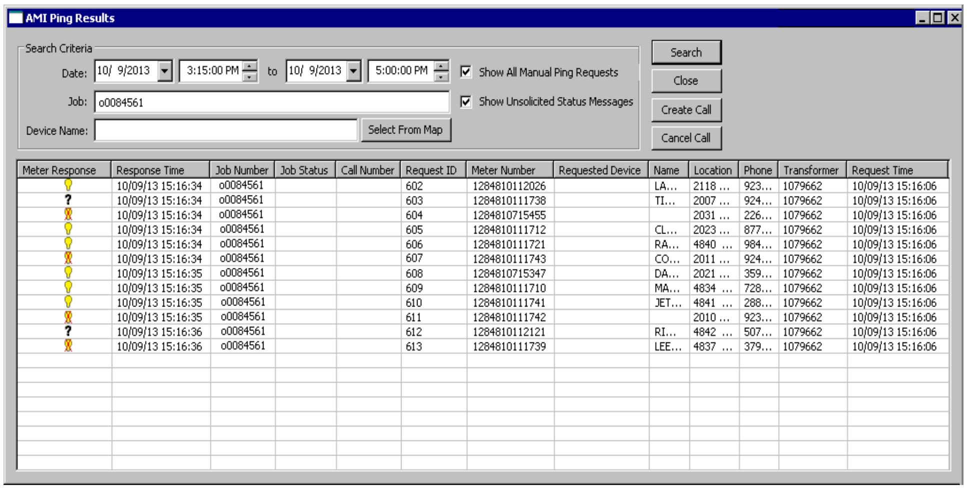
For this Operational Demonstration and Test, the Power Status Verification functionality was implemented to verify that power had been restored to all affected AMI meters upon completion of an outage trouble ticket. Figure 3-107 shows the OMS Ping Request screen, which displays the meter power status for all meters affected by an outage. In this screen, a meter status with a yellow light bulb indicates that the OMS has received an unsolicited power restoration event; a light bulb with a red X indicates that the power is off at the meter for some non-outage cause; and a gray light bulb is a meter whose current status remains undetermined.

Figure 3-107: OMS Ping Request Screen



At this point the operator, or the system at some predetermined delay after completion of the outage job, can initiate a Power Status Verification request for any meter whose current status is still undetermined. Figure 3-108 illustrates the results of the Power Status Verification request on the OMS Ping Results screen. On this screen, a meter response with a yellow light bulb indicates that the OMS has received — solicited or unsolicited — a power restoration event message; a light bulb with a red X indicates that the power is off at the meter for some non-outage cause; an hourglass indicates that the OMS is waiting for a response to an active PSV request; and a light bulb with a question mark is a meter where the current status is still undetermined.

Figure 3-108: OMS Ping Results Summary



Using the Power Status Verification function in conjunction with the meters' unsolicited Power Restoration Alerts allows the Distribution Dispatcher to quickly determine if power has been restored to all affected by the outage or identify any "nested outages" that may have been caused by another situation that was not resolved by the current outage order completion.

3.4.6.3.2.5 Issues and Corrective Actions

The following issues and corrective action were encountered during the performance of the Meter Outage Restoration operational demonstration and analysis.

Table 3-80: Issues and Corrective Actions

Issue	Corrective Action
• Difficulty correlating KCP&L's OMS event performance with production OMS event performance due to customers moving in/out, and because production OMS automatically filters out vacant properties.	• Did not attempt to correlate the project SmartGrid OMS event customer counts with production OMS event customer counts.
• Connection reliability issues between KCP&L and the MDM vendor-hosted system by causing occasional losses of communication during outage events.	• KCP&L pulled event logs directly from the AHE and correlated them against the event logs reported to OMS to close any gaps caused by connectivity issues with MDM.

3.4.6.3.3 Findings

The results obtained in the execution and analyses of the Meter Outage Restoration operational demonstration are summarized in the sections below.

3.4.6.3.3.1 Discussion

The project team performed an analysis of multiple outage events to determine the performance of the AMI network to deliver the Power Outage alert message for transformer, lateral, and feeder outages. A representative sample of the results of this analysis concluded that, for most outage events, Power Outage alerts were received from about 90% of the outaged meters, far exceeding the performance of the AMR “last gasp” communications. The analysis also concluded that, on average, Power Restoration alerts were received from more than 95% of all outaged meters, typically in less than 15 minutes.

It was demonstrated that the Power Status Verification function could be used in conjunction with the meter’s unsolicited Power Restoration Alerts to quickly confirm the outage restoration. This functionality allows the Distribution Dispatcher to quickly determine if power has been restored to all affected by the outage, or to identify any “nested outages” that may have been caused by another situation that was not resolved by the current outage order completion.

3.4.6.3.3.2 Expectations vs. Actuals

The following table provides a comparison of the Expected Results and the Actual Outcomes for the Meter Outage Restoration operational demonstration.

Table 3-81: Expected Results vs. Actual Outcome

Expected Results	Actual Outcome
• Meter outage/restoration alerts will be transported via the AMI and MDM systems, and received and processed by the OMS.	• Successfully implemented outage/restoration alerts as planned. On average 90% of outage alerts were received, and 95% of restoration alerts were received, typically within 15 minutes.
• AMI and MDM provide the active meter status in response to Power Status Verification requests issued by the OMS.	• Successfully implemented the power status verification process as planned.
• Improved outage response should result from this application. However, since the SGDP systems are not used for production outage response, this benefit will not be measurable.	• Successfully demonstrated the improved outage response capabilities, especially on the processes used to confirm outage restoration.

3.4.6.3.3.3 Computational Tool Factors

This demonstration did not produce any inputs to the Smart Grid Computational Tool benefits analysis.

3.4.6.3.4 Lessons Learned

Throughout the conduct of the operational testing and analysis of the Meter Outage Restoration function, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- Due to project constraints on interfacing to legacy systems, the project team was not able to build the functionality needed within the MDM to filter outage/restoration alerts caused by non-outage related causes. The project team was surprised by the wide variety of service orders and other routine work activities that could cause meters to report power outage/restorations. An enterprise deployment will need to build a robust MDM- or middleware-based process to verify and filter out these non-outage events.
- Power Status Verification process should incorporate an MDM- or middleware-based process to identify and respond appropriately for meters that are de-energized for some legitimate reason prior to the outage.
- The power outage wait time designed in the L+G meter significantly reduced the number of outages/restores the MDM and/or OMS needed to process for momentary outages. This is very beneficial to the OMS, unless the utility wants to use the OMS to track momentary outages. Through the meter metrology there are other mechanisms to track customer-experienced momentary outages; the meter interval data flags intervals with momentary power loss.
- L+G's implementation of Power Status Verification currently issues an on-demand read to the meter. A timer was built into the MDM so that if no read response was received an appropriate response was sent to the OMS. More robust functionality could be developed for the MDM, or middleware, to periodically resend the Power Status Verification to the AMI for some period of time, removing this workload from the OMS dispatcher.
- A filter by feeder was not able to be implemented. This was because of the way the MDM created its groupings of bellwether meters. While working through the requirements for this functionality, the value of a predefined group — for filtering based on a normal switching configuration — began to be questioned, as the filter would provide erroneous results whenever the system was in an abnormal configuration.

3.4.6.4 Demand Response Events

Demand Response is a demonstration of one aspect of the Real Time Load Measurement & Management function.

3.4.6.4.1 Overview

The following sections provide an overview of the operational, demonstration, testing, and evaluation methodology used for the Demand Response Events operational demonstration.

3.4.6.4.1.1 Description

The implementation of a DERM system in conjunction with a PCT and other HAN connected devices will enable advanced utility utilization of demand response on the distribution system. The DERM will maintain a sophisticated distributed energy resource inventory and will be capable of forecasting, scheduling, selecting, and executing load control programs for all or select devices.

Two types of DR events were considered for implementation and testing. First, for stand-alone PCTs communicating directly to the AMI, a DLC DR event was issued through the AMI system. Second, for HAN connected PCTs and devices, a Pay for Participation (PFP) DR event was considered for issuance through the HEMP/HAN infrastructure. In both cases, demand response events could be scheduled and executed system wide or could be isolated or grouped to affect only targeted circuits or sections of the distribution system to support reliability.

3.4.6.4.1.2 Expected Results

This operational demonstration was expected to yield the following:

- Implementation of DR events in accordance with OpenADR 2.0, IEC-61968-9, and ZigBee SEP 1.x would provide experience and education for the industry.
- DMS/DERM/HEMP/AHE/PCT integration would enable utility-controlled (DLC) reduction in kW on the entire system or on select groups of PCTs.
- DMS/DERM/HEMP/HAN integration would enable customer managed (PFP) reduction in kW on the entire system or on selected groups of HAN connected PCTs and other devices, provided such integration would fall within program definitions.
- An assessment of the ability of DERM/DMAT to post process AMI data to determine the level of demand reduction achieved by each event participant.

3.4.6.4.1.3 Benefit Analysis Method/Factors

The DOE SGCT was used to perform the SGDP benefit analysis. For this application the following potential Smart Grid Function benefits were identified.

- Deferred Generation Capacity Investment
- Deferred Distribution Capacity Investment

For these benefits the following factors are required for the SGCT.

Deferred Generation Capacity Investment

- Demand Response Used at Annual Peak Time (MW)

Deferred Distribution Capacity Investment

- Demand Response Used at Distribution Peak Time (MW)

The contribution to these DR benefit factors from the BESS and EVCS are derived and presented in the appropriate energy storage operational demonstrations and testing results. The project team had planned to use this Demand Response Events operational demonstration and testing to quantify the contribution to these factors from the SmartEnd-Use programs and technologies deployed. Due to the limited number of devices deployed and many technical issues and other constraints, the project team was unable to quantify the system level impact of the SmartEnd-Use DR events.

3.4.6.4.1.4 Demonstration Methodology

The following points provide an overview of how the technical demonstration of this application was accomplished:

- DERM included DR assets deployed by Smart End use programs.
- User was capable of creating programs for thermostats and HANs in the DERM.
- DMS identified potential overload or company system peak events and called on the DERM for assistance.
- DERM evaluated options and created DR events.
- DERM dispatched DR events.
- DERM-scheduled and -executed DR events were tracked by the DERM system and participant compliance was tracked by the HEMP system.
- Post-event analysis or the of the residential DR load reduction was performed.

3.4.6.4.1.5 Analytical Methodology

The following points provide an overview of the analytical methods that were used to evaluate the impact and benefits of this application:

- Interval load data for customers participating in DERM DR programs were measured through KCP&L's AMI system deployed as part of the project.
- The DERM/DMAT constructed load profiles for each program participant from available interval AMI metering data.
- DERM-scheduled and -executed DR events were tracked by the DERM system and participant compliance was tracked by the HEMP system.
- project team performed after-the-fact analysis of DR events to determine the level of demand reduction achieved by select residential event participants.

3.4.6.4.2 Plan Execution and Analysis

The following sections provide details regarding the functional tests performed, data collected, and analysis performed for the Demand Response Events operational test.

3.4.6.4.2.1 Overview

In order to perform the demand response testing, KCP&L first had to build interfaces between all of the relevant systems. Figure 3-109 shows the DR integration architecture implement and Figure 3-110 and Figure 3-111 show the system-to-system and system-to-device integration for the DMS-initiated DR events. The flow starts at the DMS, which detects a potential overload. The DMS sends this information to the DERM via the Enterprise Service Bus (ESB). The DERM determines which assets to call upon for demand response assistance, and it sends this information to the HEMP via the ESB. For the stand-alone PCTs, the HEMP sends the DR event on to the AHE via the ESB. Then the AHE sends the DR event to the relevant meters. The meters transmit the DR event to their respective PCTs. For the Home Area Network devices the sequence is similar, except once the HEMP gets the DR event, it sends it on to the appropriate Home Area Network Gateways, which send the DR event to their respective PCTs or LCSs.

Figure 3-109: Implemented DR Integration Architecture

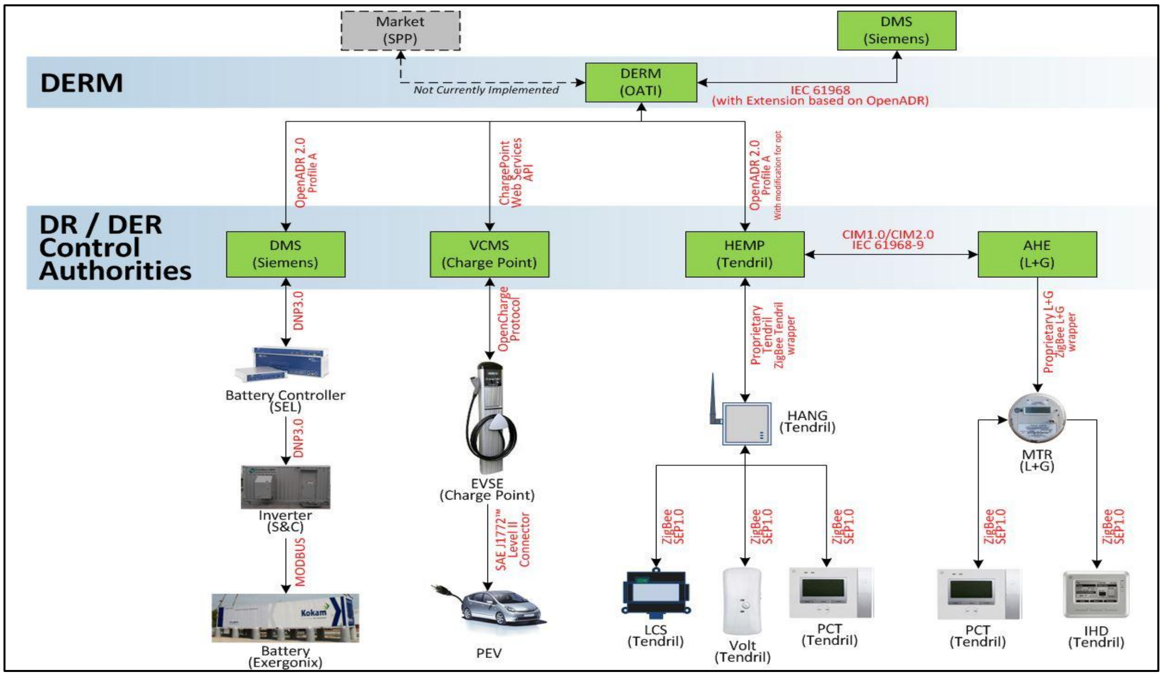


Figure 3-110: DMS-Initiated DR Event Interoperability – Stand-Alone PCTs

Figure 3-111: DMS-Initiated DR Event Interoperability – HANs

This particular operational test focused on demand response events to residential devices, but KCP&L also utilized a grid-scale battery and a set of electric vehicle charging stations for DR events. For information about demand response integration to the battery, see Section 2.2.5.2.1.3. For information about demand response integration to the VCMS, see Section 2.2.5.2.1.4. For the complete DR test scripts to the battery and the VCMS, see Appendices K.4 and K.5.

3.4.6.4.2.2 DR Event Types

Originally, KCP&L planned to conduct two different demand response event types: DLC and PFP. The DLC programs would have prescribed specific responses from the target devices, whereas the PFP programs would allow the users to define how they wanted their devices to respond. In general, the DLC events would be targeted toward the stand-alone thermostats, and the PFP events would be targeted toward the HAN devices – the thermostats and load control switches connected to a Home Area Network Gateway. Since the stand-alone thermostats used only KCP&L communications (namely the L+G metering network), they were more dependable. Each HAN, however, relied on a customer's broadband Internet connection, so there was one more layer of potential communication breakdown; hence, KCP&L would consider any response from the PFP events as "bonus" and wouldn't rely on these devices and the PFP program if necessary.

For the DLC events, KCP&L wanted to implement thermostat cycling with the fan continuously running, but there were some technical issues with this plan. ZigBee SEP 1.x didn't support cycling events or fan control, and ZigBee SEP 2.0 was still evolving, so KCP&L was forced to implement a temperature offset DR event for the DLC events. Despite these issues, KCP&L was still able to implement DLC events during the operational testing of the project.

KCP&L also encountered issues with the PFP events, and these problems kept KCP&L from implementing PFP events during operational testing. KCP&L designed PFP programs in the DERM, but none of the target systems (HEMP, VCMS, or DMS for battery events) evolved to where they could consume a price-based message. The HEMP required product enhancements in order to allow customers to set their preferences for price-based DR events. These enhancements were not completed in time for operational testing. Additionally, the event messaging standards weren't quite ready for price-based DR. OpenADR 2.0 was still in progress during the project, and price-based messages were not feasible without extensions to the A profile. Finally, in order for KCP&L to conduct price-based events, a new tariff would have been necessary. This would have required significant investments of time and regulatory efforts to clear the way for price-based events in what would have been a limited operational testing time frame.

Since KCP&L wasn't able to conduct PFP events, the battery, charging stations, and HAN devices were included in the DLC demand response events, along with the stand-alone thermostats and HAN devices.

3.4.6.4.2.3 Residential DR Event Parameters

In accordance with the SmartGrid tariffs and customer communications, the residential DR events were scheduled from 4 PM to 6 PM. No emergency events were called due to overloads; rather, all events were scheduled. The DERM operator always notified the SmartGrid Support Team the day that an event was planned so that the Support Team was ready to field any customer calls. The residential DLC event called for the target thermostats to raise their setpoints by 3° F for the duration of the event.

Based on tariffs and communications, KCP&L DR events were required to conform to the following constraints:

- 2-4 events could occur during July.
- 3-5 events could occur during August.
- Events could occur only Tuesday through Friday;
- Events couldn't be conducted on a Holiday.
- Events couldn't be conducted on more than two (2) consecutive days.
- Events could only target only thermostats; the load control devices were not included in the operational tests.

3.4.6.4.2.4 Electric Vehicle Charge Station DR Event Parameters

Demand response events targeted at the electric vehicle charging stations simply halted the charging capabilities of the station during the defined time period. If a vehicle was plugged in when the DR event began, the event would result in load reduction. If no vehicle was plugged in or the vehicle was fully charged, then no load reduction would be seen.

KCP&L didn't have many formal limitations on DR events to the charging stations; however, the utility still chose to limit its use of these DR events for several reasons. Most of the charging stations were located at the site of commercial and industrial (C&I) customers, and KCP&L could easily communicate about the DR events to these C&I customers. The people that actually used the charging stations might not be employees of the C&I customers, so it would be difficult to communicate the upcoming event to the end user actually plugged into the station. Additionally, since the charging infrastructure was new in Kansas City and the SGDP was supposed to encourage the use of PEVs, scheduling DR events to the relatively few PEV drivers to interrupt their charging was perceived as a conflicting message. Due to these potential concerns, KCP&L excluded the charging stations from most DR events.

KCP&L did conduct one test on August 13, 2014 involving an actively charging station. See Appendix K.5 for a step-by-step view of this test. The primary purpose of this testing was to verify that the system-to-system interfaces and messages were functioning properly.

3.4.6.4.2.5 Grid-Connected Battery DR Event Parameters

Demand response events targeted at the grid-connected battery caused the battery to discharge at a specific rate for a defined period of time. For the DERM to utilize the battery for DR, the battery had to be set to DERM mode in the Intergraph GUI. When in DERM mode, the battery wouldn't charge or discharge on its regular schedule; rather, it would remain fully charged so that it would be ready when the DERM would call upon it.

Since DR events to the grid-connected battery didn't directly affect any customers, there weren't as many limitations on these events. KCP&L was able to test out battery DR events as desired throughout the operational testing period without needing to notify customers or the SmartGrid Support Team. See Appendix K.4 for a step-by-step view of the battery DR tests.

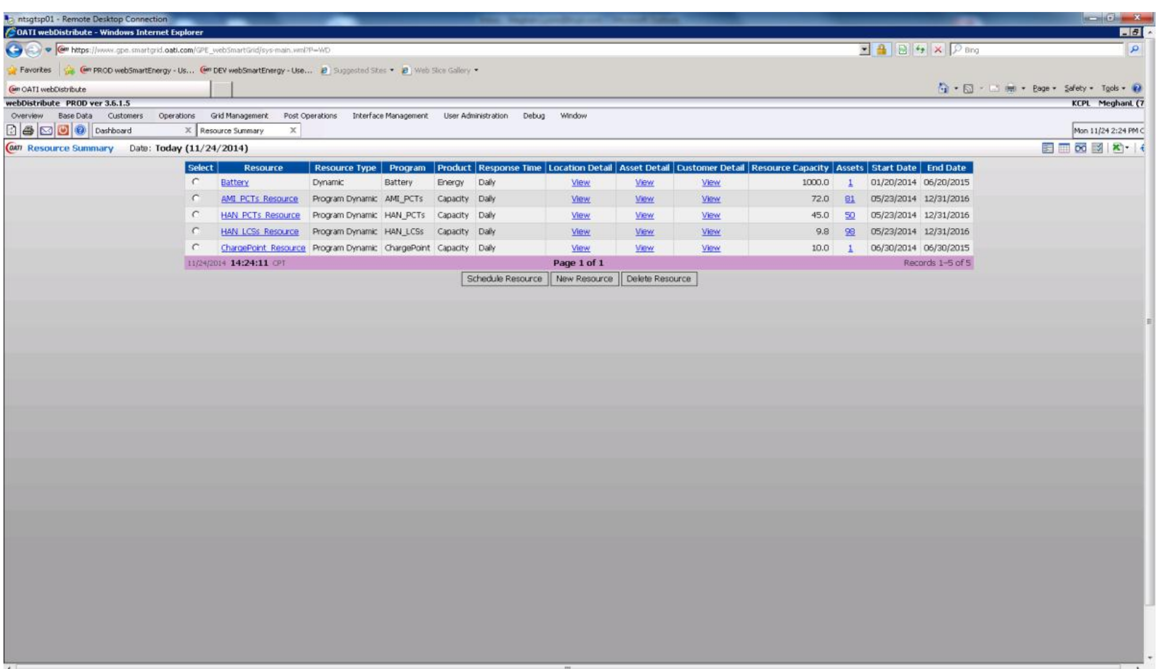
3.4.6.4.2.6 DERM Initiates System-wide Events

Some of the DR events conducted for operational testing were triggered out of the DERM, rather than from the DMS. When the DERM initiated events, all participants in a particular program were included in the DR event, regardless of the customer's geographic location.

Figure 3-112 below shows the programs that KCP&L set up in the DERM. They included:

- The grid-connected battery
- Stand-alone thermostats
- HAN thermostats
- HAN load control switches
- Electric vehicle charging stations

Figure 3-112: DERM Initiating System Wide DR Events by Program



From the Resource Summary screen in the DERM, the operator could easily trigger demand response events to all participants in a particular program. The operator simply selected the program that he wanted to call upon and then pressed the Schedule Resource button. From there, he entered the desired time frame for the DR event and, finally, he committed the event. Once the notification time approached, the DR event message was dispatched out to the target system via the DERM.

3.4.6.4.2.7 DMS Initiates Geographically Targeted Events

Other DR events conducted during operational testing were targeted toward a specific location in the network topology. These events occurred when the DMS sensed an impending or immediate overload somewhere on the network. The DMS communicated the current or potential overload to the DERM, and then the DERM selected the DR resources necessary to resolve the overload. The DERM's proposed solution might include DR assets from only one program, or it might include DR assets from a number of programs.

For operational testing, KCP&L had to do some manipulation, because overloads weren't actually occurring on the smart grid feeders. A user-controllable limit was set up on particular sections in DMS. These limits were modified as needed to generate different overloads for real-time values; this eliminated the need for manipulating field values for testing purposes, as an overload or overvoltage could be generated on real-time values. As a result of these limits, the DMS sent "PowerFlowLimitViolation" messages to the DERM. Figure 3-113 below shows the screenshot at the DERM once the overload message propagated from the DMS to the DERM.

Figure 3-113: DERM Displays Circuit Violation

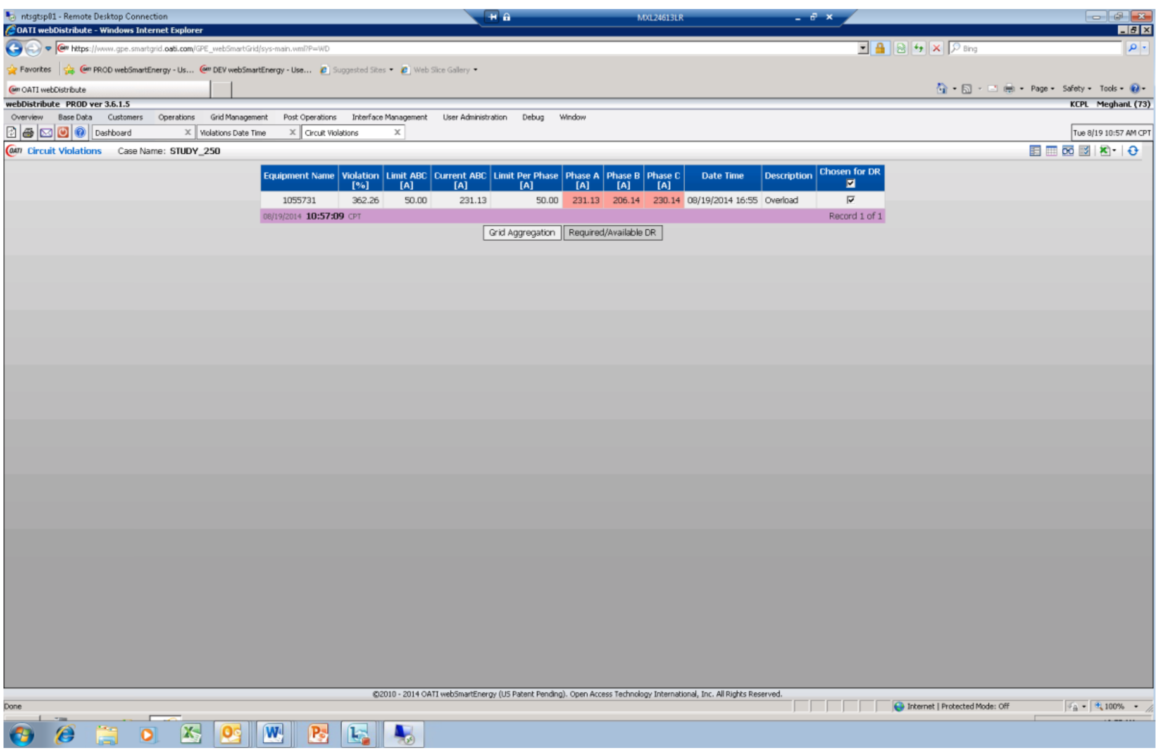
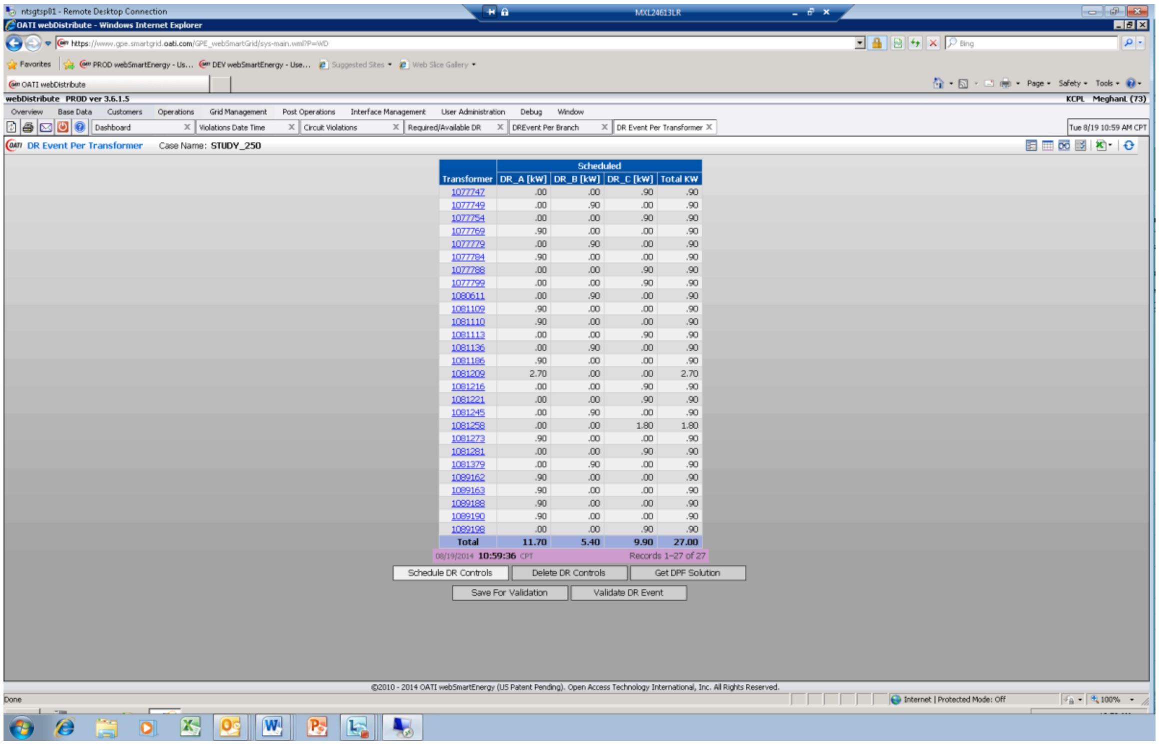


Figure 3-114 shows the resources that the DERM recommended calling upon to resolve the feeder overload. As is evident in the screenshot, the resources were selected by network location – in this case, they were grouped by transformer.

For a step-by-step view of the DMS-initiated DR events, refer to Appendix K.2.

Figure 3-114: DERM Proposes DR Resources DMS-Triggered DR Events



3.4.6.4.2.8 Event Execution and Participation

The residential DR events were conducted during July and August 2014. The event parameters are described in Section 3.4.1.1.2.3 above. Some of the events were initiated from the DERM and targeted towards *all* the PCTs – both the stand-alone PCTs and the HAN-connected PCTs. Others were initiated from the DERM and targeted towards just the HAN PCTs. Finally, some events were triggered by an overload in the DMS and dispatched to a geographic target of devices. Table 3-82 below summarizes the residential DR events.

Table 3-82: DR Event Participation

Event Date	Initiating System	Target HAN PCTs	HAN PCT Participants	Target AMI PCTs	AMI PCT Participants	Opt Outs
7/8/2014	DERM	53	18	75	12	2
7/17/2014	DERM	50	18	0	0	0
7/22/2014	DERM	50	17	82	11	3
7/31/2014	DERM	50	18	81	10	3
8/13/2014	DERM	50	16	81	71	7
8/19/2014	DMS	4	0	26	20	4
8/21/2014	DERM	50	15	80	63	10
8/26/2014	DERM	50	15	80	62	7
8/28/2014	DMS	4	0	26	24	1

If all systems were communicating perfectly, then the target numbers would equal the participant numbers plus the opt outs. This was not the case for any of the events. As shown in the table above, the first three events yielded very low participation rates. Upon investigation with Tendril, a bug was discovered in the code, and that bug was causing message timeouts to occur between Tendril and the ESB. Upon deployment of Tendril's code fix, participation increased dramatically from the AMI PCTs. Even after that, however, there was always at least one AMI PCT that didn't acknowledge receipt of the DR notification.

The table above also illustrates some of the issues that KCP&L experienced with the HAN devices. From KCP&L's vantage point, there were a number of HAN PCTs that were out of contact for a variety of reasons. The high move-in/move-out rates in the demonstration area (~30%) made it very difficult to keep meterIDs and customer service point identifiers (SPIDs) synchronized, and this was important for proper delivery of event notifications. It was also difficult to determine why these HAN PCTs weren't reachable. The HAN might have been unplugged, the internet connection might have been down, or some other issue might have occurred. From KCP&L's perspective, failures could occur either at the HAN gateway level or at the device level. KCP&L couldn't get specific information from Tendril's HEMP about why these devices were out of contact, so the only way to resolve these issues would have been through case-by-case troubleshooting with the SmartGrid Support Team. This was done on a very limited basis for this project.

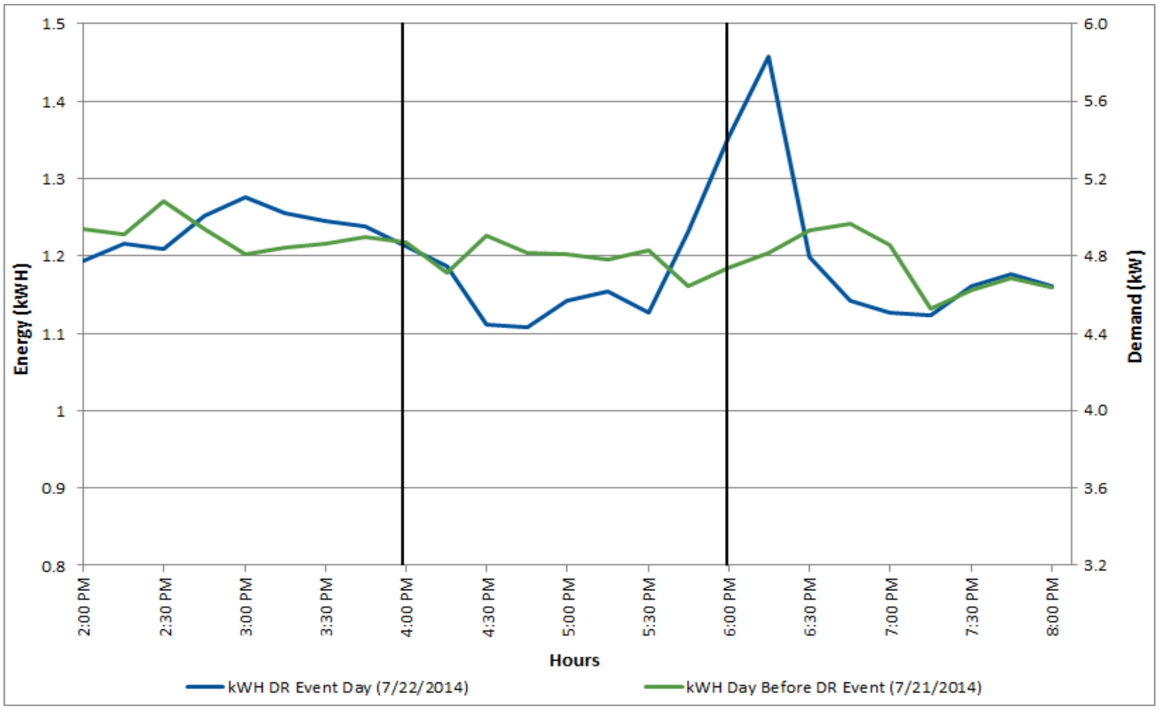
3.4.6.4.2.9 DR Load Response Analysis

The purpose of the demonstration wasn't to focus on the load reduction due to the DR events; rather, the goal was to complete end-to-end messaging and conform with industry standards. But KCP&L did analyze the effectiveness of the various demand response programs by comparing the customer load data with the DR event data.

Figure 3-115 below shows 15-minute interval load consumption data plotted during two "like" days – two consecutive summer days with similar (hot) temperatures. One day was a DR day and the other day was not. The 15-minute data shows total consumption over the 15-minute time period, in kWh. This data is for a single residential customer, but it highlights a few concerns with KCP&L's thermostat setback program.

- As expected with a setback program, there was less DR reduction in the latter half of the event than during the first half. This could be seen by comparing the difference between the red and blue data points – the difference was more significant between 4 PM and 5 PM than between 5 PM and 6 PM. If KCP&L had been able to use a thermostat-cycling program, the DR reduction would have been more consistent throughout the event.
- As expected with a setback program, there was a spike in load at the completion of the DR event. The residential DR events were scheduled to end at 6 PM, with some ZigBee randomization on the end times. The blue data points (the DR day) show that there was a significant increase in the load at the end of the DR event. Some of this spike could have been due to other factors, such as cooking, laundry, etc., but a significant portion of it likely was due to the thermostats resetting back to their original setpoint and the air conditioning running continuously to cool the residence down.

Figure 3-115: Load Reduction from PCT DR Event



3.4.6.4.2.10 Issues and Corrective Actions

The following issues and corrective action were encountered during the performance of the Demand Response Event operational testing and analysis.

Table 3-83: Issues and Corrective Actions

Issue	Corrective Action
• None of the target systems could handle Pay for Participation programs.	• Since KCP&L wasn't able to incorporate PFP events, the battery, charging stations, and HAN devices were included in the DLC demand response events.
• OpenADR 2.0 standards development wasn't complete in time for implementation by KCP&L.	• Since OpenADR 2.0 was still in progress, KCP&L implemented a prerelease draft version of Profile A. As a result, the vendors had to implement extensions to allow for opt-out functionality.
• KCP&L wanted to implement thermostat cycling with the fan continuously running for the DLC events, but ZigBee SEP 1.x didn't support cycling events or fan control.	• Due to the ZigBee issues with thermostat cycling, KCP&L had to implement a temperature offset DR event for the DLC events.
• With the vendor's ZigBee SEP 1.x implementation, DR events could not distinguish between the 120 V outlet switch (Volt) and the 240 V water heater switch (LCS). DR events to the outlet switch may lead to unnecessary customer dissatisfaction.	• Since very few LCS switches were installed on water heaters due to the high penetration of gas water heating, KCP&L decided to eliminate the LCS and Volt from the DLC DR events.

• First three AMI PCT events resulted in very low participation percentages.	• After some investigation, KCP&L discovered that there was a bug in Tendril's code that was causing messaging timeouts between Tendril and the ESB. Tendril developed a code fix and deployed it to production prior to the 8/13 event, and this greatly improved participation percentage during the remaining events.
• Seeing low participation percentage from HAN PCTs due to devices being "out of contact" with Tendril (not powered on, no internet connectivity, etc.).	• The SmartGrid Support Team tried to troubleshoot and resolve issues on a case-by-case basis, but in many cases team members were unable to determine the cause of the issue.
• No automated process for updating customers in back office systems when customer move-ins/move-outs or meter swap-outs occurred.	• KCP&L implemented a batch process to synch the HEMP and AHE on a weekly basis to update the meterID and SPID linkages.
• Due to the logic programmed in the Real Time Automation Controller (RTAC), the battery events had to start on the hour and be in hour increments.	• KCP&L and Siemens included some validation code in the battery DR logic so that the DERM would receive an error if an event was scheduled to start or end off of the hour.
• No actual overloads occurred in the DMS on the SmartGrid feeders.	• KCP&L DMS operator had to modify setpoints to create "fake" overloads. This allowed KCP&L to test out the end-to-end, DMS-triggered DR events.

3.4.6.4.3 Findings

The results obtained in the execution and analysis of the Demand Response Event operational test are summarized in the sections below.

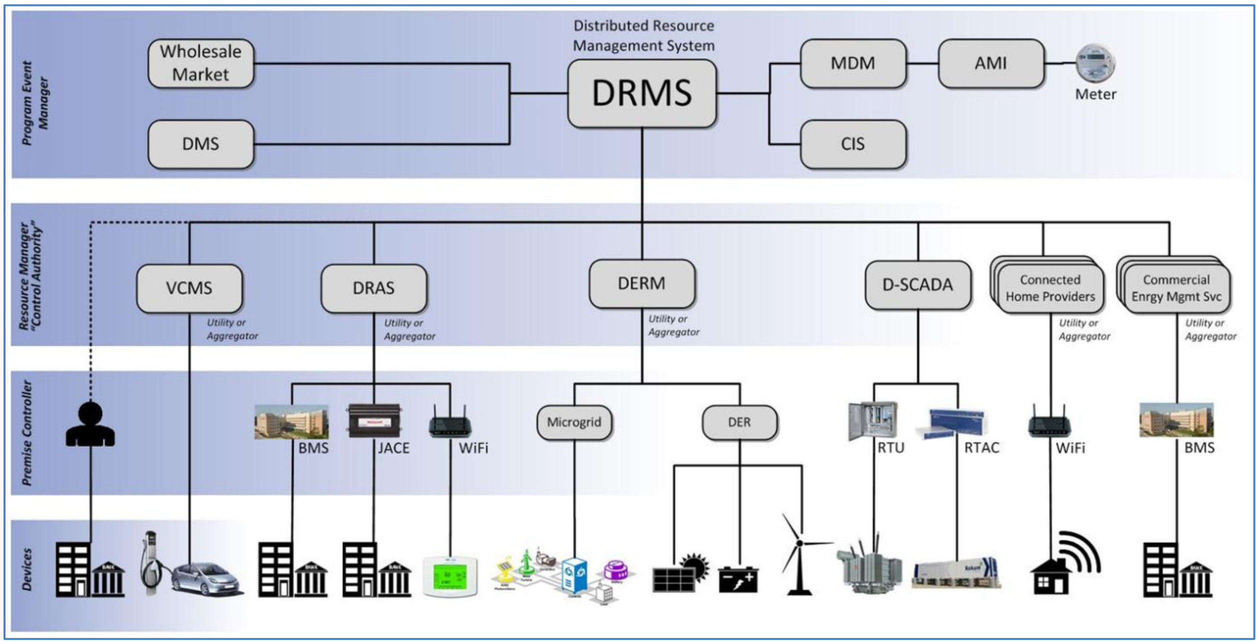
3.4.6.4.3.1 Discussion

Throughout KCP&L's project, it became apparent that standards evolution is a major barrier to DR design and implementation. Many of the emerging smart grid standards for DR have taken longer than expected to develop, and upon completion there are few standards that have certification bodies intact to enforce the desired implementation. In addition to these issues, there are multiple standards-creation bodies that are attempting to develop messaging standards for similar functionalities. For example, ZigBee and OpenADR 2.0 both allow DR messaging capabilities to the end devices in a home. Simply choosing to implement a smart grid standard for DR messaging is not sufficient. In the future, utilities will have to carefully consider which standard they want their internal developers and their vendors to abide by.

Another major finding from KCP&L's DR implementation had to do with DR architecture. The project team believes that utilities should look to adopt a Demand Response Management System (DRMS) that oversees both DER and DR assets and communicates with multiple DR/DER control authorities. This approach is what KCP&L took with its OATI DERM implementation, and it is proving to be a good strategy. This tiered approach to DR allows the DRMS to focus on the event planning and orchestration, and it leaves the device communications to the control authorities.

Figure 3-116 shows KCP&L's vision for demand response architecture and resources moving forward. The figure depicts one overarching system (the DERM) and a number of control authorities that are responsible for communications with the end DR or DER.

Figure 3-116: KCP&L's Proposed DR Architecture of the Future



Lastly, although KCP&L focused its DR efforts for this project on the messaging standards and the end-to-end interoperability between systems, some insight was gained for future DR programs. Since cycling events were not feasible with ZigBee SEP 1.x (and 2.0 wasn't fully complete), KCP&L had to use a thermostat setback event for residential DR. Although KCP&L didn't focus much on calculating load reduction from DR events, it was apparent that the setback events resulted in a reduction in DR during the second hour of the event. Future thermostat DR programs at KCP&L will likely utilize cycling with fan control which will provide a consistent load reduction over the duration of an event.

3.4.6.4.3.2 Expectations vs. Actuals

The following table provides a comparison of the Expected Results and the Actual Outcomes for the Demand Response Event operational test.

Table 3-84: Expected Results vs. Actual Outcome

Expected Results	Actual Outcome
• Implementation of DR events in accordance with OpenADR 2.0, IEC-61968-9, and ZigBee SEP 1.x will provide experience and education for the industry.	• KCP&L utilized OpenADR 2.0, IEC 61968-9, and ZigBee SEP 1.x for the demand response component of the SGDP. Although the standards-development process took longer than anticipated by industry, KCP&L participated in the development where possible and fed suggestions back for inclusion. • OpenADR 2.0 Profile A was implemented, with slight modifications to allow for opt outs. Once Profile B is completed, this modification will not be necessary. • Thermostat-cycling capabilities were not supported in ZigBee SEP 1.x, so KCP&L had to implement setback events instead.
• DMS/DERM/HEMP/AHE/PCT integration will enable utility-controlled (DLC) reduction in kW on the entire system or on select groups of PCTs.	• DMS/DERM/HEMP/AHE/PCT integration enabled utility-controlled DLC events on the entire system. This was accomplished by scheduling a DR event from the DERM for all devices enrolled in a particular program (thermostat setback, battery, or vehicle charge stations). This integration also enabled DR events to be called in a specific geographic area. This was accomplished when an immediate or future overload was sensed on a particular feeder by the DMS. The DMS passed this information along to the DERM, which then called on the relevant resources for DR.
• DMS/DERM/HEMP/HAN integration will enable customer managed (PFP) reduction in kW on the entire system or on selected groups of HAN connected PCTs and other devices.	• Although the DERM was capable of calling customer managed, price-based events, none of the target systems were able to accept these DR messages. As a result, KCP&L included the HAN devices, the grid-connected battery, and the electric vehicle charging stations in the DLC events instead of the originally intended PFP events.
• The ability of DERM/DMAT to post process AMI data will determine the level of demand reduction achieved by each event participant.	• Although the DERM was capable of calling customer managed, price-based events, none of the target systems was able to accept these DR messages. As a result, KCP&L included the HAN devices, the grid-connected battery, and the electric vehicle charging stations in the DLC events instead of the originally intended PFP events.

3.4.6.4.3.3 Computational Tool Factors

This demonstration did not produce any inputs to the Smart Grid Computational Tool benefits analysis.

The project team had planned to use this Demand Response Events operational demonstration and testing to quantify the contribution to these factors from the SmartEnd-Use programs and technologies deployed. Due to the limited number of devices deployed and many technical issues and other constraints, the project team was unable to quantify the system level impact of the SmartEnd-Use DR events.

The Computational Tool factors from the BESS and EVCS Demand Response Events are derived and presented in the appropriate energy storage operational demonstrations and testing results.

3.4.6.4.4 Lessons Learned

Throughout the demonstration of the Demand Response Event operational test, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- The standards-creation process can be slow and tedious. To utilize OpenADR 2.0, KCP&L had to pick a working draft version of Profile A and implement to that version. Waiting for the “completed” profile would have been detrimental to the project schedule, so this wasn’t an option. Once the OpenADR 2.0 profiles are fully vetted and a vendor certification process is in order, it will be a lot easier and faster for companies to develop their products to the new standard.
- In addition to a standard profile, there is a clear need for testing agencies to certify deployments of a particular standard. Even with profiles there is room for interpretation, so testing bodies will help to ensure consistency in the certification process across vendors.
- For KCP&L’s implementation the DERM sent the HEMP a list of assets for participation, as opposed to a group’s name. The grouping logic was done at the DERM level, but for an enterprisewide deployment it makes more sense for this logic to occur in the respective control authority. For example, the DERM would send a DR event to the HEMP, addressed to a particular section of the network. The HEMP would translate this network segment into a DR event dispatched to a list of devices in that segment. This type of design would also position the DERM to interface with external aggregators.
- The HAN devices associated with one customer account aren’t transferred to the next account when a new person moves in. As a result, assets are left stranded – they aren’t moved to the new residence, but they aren’t usable by the new resident at the original premises without significant manual intervention. If deployed on an enterprisewide scale, careful thought would need to be given as to how to efficiently transition assets with move-ins/move-outs. Strategies might be different for houses than for apartments.
- Customer Wi-Fi connections were not always reliable. KCP&L learned that active communications monitoring was needed with the HAN, and that customer support needed to reach out to customers when there were issues. KCP&L didn’t actively monitor the HANs for this project, but this would be a requirement moving forward with new programs.

3.4.7 Customer Electricity Use Optimization

Customer electricity use optimization is possible if customers are provided with information to make educated decisions about their electricity use. Customers should be able to optimize toward multiple goals such as cost, reliability, convenience, and environmental impact.

3.4.7.1 Historical Interval Usage Information

Historical Interval Usage Information is a demonstration of one aspect of the Customer Electricity Use Optimization function.

3.4.7.1.1 Overview

The following sections provide an overview of the operational, demonstration, testing, and evaluation methodology used for the Historical Interval Usage Information operational demonstration.

3.4.7.1.1.1 Description

All customers in the SGDP were provided access to the KCP&L-hosted Home Energy Management Portal, a website that presents customers with various tools with which they may visualize and analyze their detailed energy usage history. This website was branded and marketed as "MySmart Portal." The HEMP website was accessible through KCP&L's AccountLink website and provides customer with:

- Historical usage information, in 15-minute intervals, generated from the customer's smart meter and presented within user-friendly visualizations, allowing the customer to evaluate energy consumption.
- A daily bill update that provides Bill to Date, days remaining in billing period, and an Estimated Bill Projection based on current consumption patterns.
- Information, tools, advice, and programs to manage and reduce electricity costs.

3.4.7.1.1.2 Expected Results

With the additional information that the HEMP provides the consumer, it was expected that:

- Customers would use the historical interval metering data available on the HEMP to better understand their total energy consumption and patterns.
- Customers would find the Bill to Date and Estimated Bill information provided on the HEMP useful in managing their energy usage costs.
- HEMP users would reduce their overall energy consumption. Other studies have shown that HEMP users may reduce their overall energy consumption by as much as 1-5%.

3.4.7.1.1.3 Benefit Analysis Method/Factors

The DOE SGCT was used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits were quantified.

- Reduced Electricity Costs

Benefits were calculated using SGCT formulas. The following factors were measured, projected or calculated during the application operation and/or demonstration.

Reduced Electricity Costs (Consumer)

- Reduced Total Residential Electricity Cost ($).

3.4.7.1.1.4 Testing Methodology

The following points provide an overview of how the operational demonstration and testing for this application was accomplished:

- 15-minute interval load data was collected for all HEMP participants throughout the project period through KCP&L's AMI system deployed as part of the Project.
- 15-minute interval load data from was collected for a HEMP control group throughout the project period using KCP&L's AMR system deployed outside of the project area.
- All interval meter data was stored in KCP&L's MDM and DMAT systems.
- At the conclusion of the operational period (through September 2014), HEMP participants' interval and aggregate usage data was compared to coincident control group interval and aggregate usage data.

3.4.7.1.1.5 Analytical Methodology

The following points provide an overview of the analytical methods that were used to evaluate the impact and benefits of this application:

- 15-minute interval load data for the control group and HEMP participants were extracted from KCP&L's DMAT for analysis.
- Load profiles of HEMP participants were compared to those of select control group customers on an hourly, daily, and monthly basis to evaluate the average or typical impact HEMP exhibits on measured participant energy usage. Calculated impacts were assessed for statistical significance.
- Willing HEMP participants were surveyed by a third party to solicit feedback on their experience using the HEMP website to determine their primary application of the tool and information provided.

3.4.7.1.2 Plan Execution and Analysis

The following sections provide details regarding the functional tests performed, data collected, and analysis performed for the Historical Interval Usage Information operational demonstration.

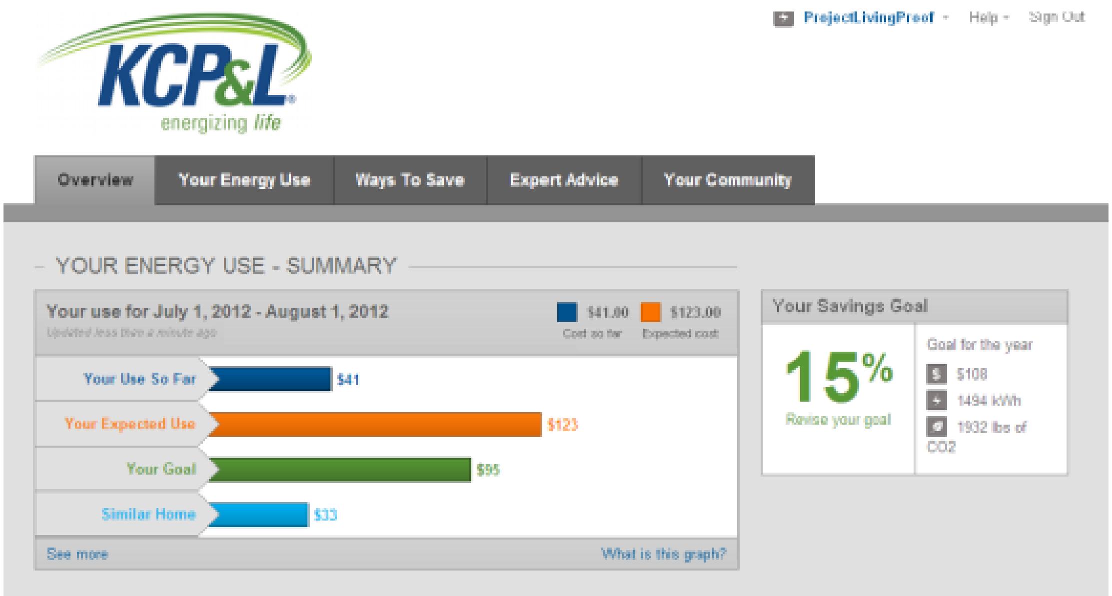
3.4.7.1.2.1 Functionality Deployed

The Customer Home Energy Management Web Portal program was rolled out to KCP&L customers in October 2010, coinciding with the AMI implementation and IHD deployments.

One of the main functions of the HEMP was the ability for customers to view information about their energy usage. Customers with stand-alone thermostats received usage data on a day-behind basis, whereas customers with HANs received real-time usage data.

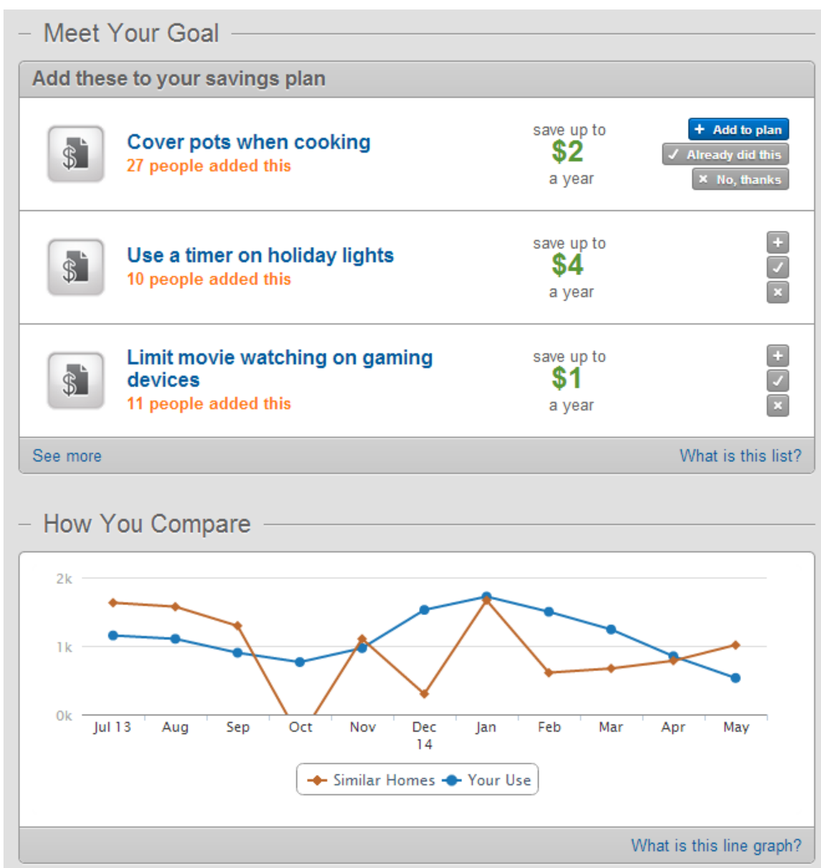
The HEMP was also used to present estimated billing information to the customer. The bill estimate provided an end-of-bill-cycle projected bill based on usage to date in a given billing cycle. A special process was created to estimate the customer billing information with accurate taxes and fees based on the customer's current rate. This historical billing information and daily estimated bill "true-up" was displayed in the HEMP portal. Figure 3-117 shows the usage data and the bill true-up displayed on the portal dashboard.

Figure 3-117: HEMP Energy Usage and Bill True-Up



Another feature of the portal was to provide customers with suggestions for how to be more energy-efficient. Customers were also able to compare their usage against that of their neighbors. Figure 3-118 below shows these capabilities.

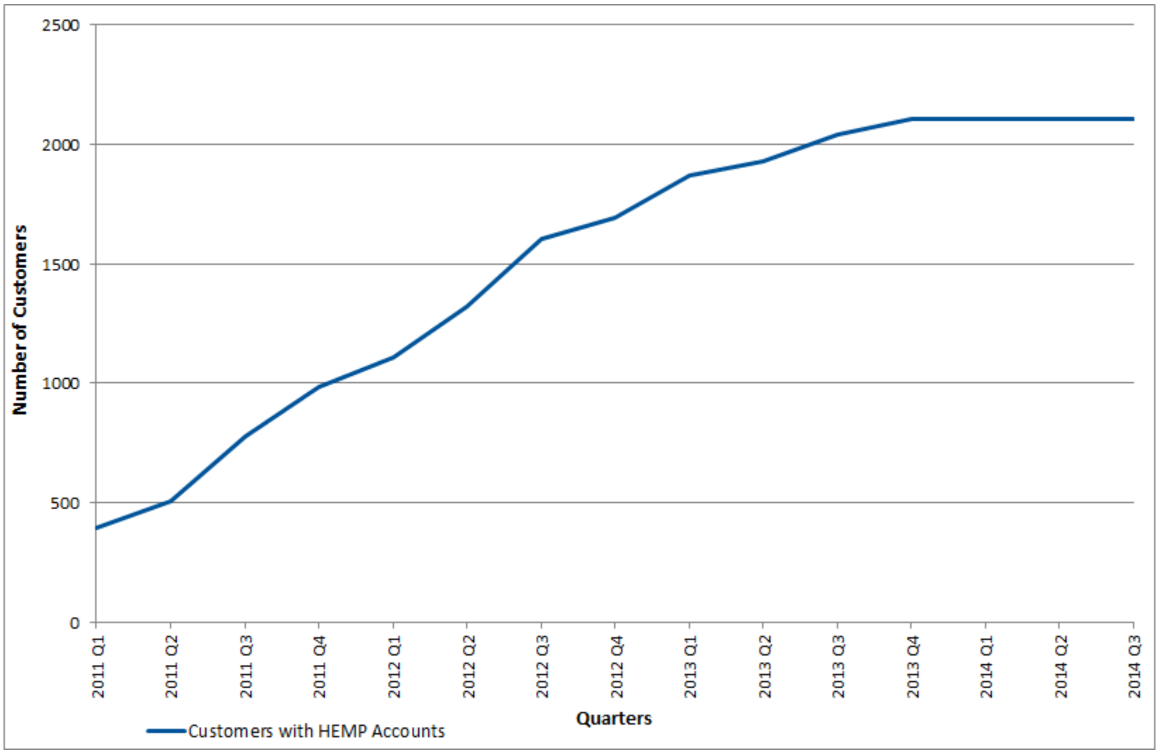
Figure 3-118: HEMP Energy Efficiency Suggestions and Neighbor Comparisons



3.4.7.1.2.2 Program Participation

Customers with SmartGrid AMI meters were eligible to create an account in the HEMP. Throughout the duration of the program, the HEMP was available to approximately 12,000 customers. At the peak of the program, there were 2,109 customers with portal accounts. Figure 3-119 below shows the enrollment in the portal from the inception through the completion of the program.

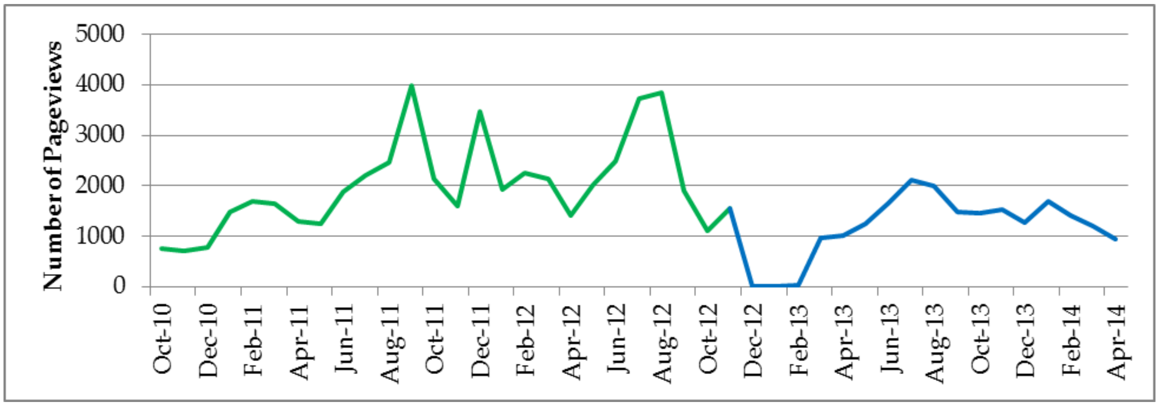
Figure 3-119: HEMP Enrollment Over Time



In addition to tracking the total number of customers who created an account on the portal, KCP&L also wanted to gain insight about the behaviors of these account holders over time. Google Analytics was used to track portal usage over time. A few major takeaways were found based on Navigant's analysis of the Google Analytics data.

Figure 3-120 below shows the portal page views over time, defined as, "The number of pages viewed, including repeated views of a single page." Throughout the duration of the program, there were two different versions of the Tendril portal. The green portion of the graph below shows the page views during the first version of the portal, and the blue portion shows the page views during the second version of the portal. As shown, the page views fluctuated significantly over the program duration, hitting peaks in September 2011, December 2011, August 2012, and July 2013. These spikes correspond well with the HEMP registrations that were occurring, showing that spikes in page views can be attributed to new users visiting the portal to create an account.

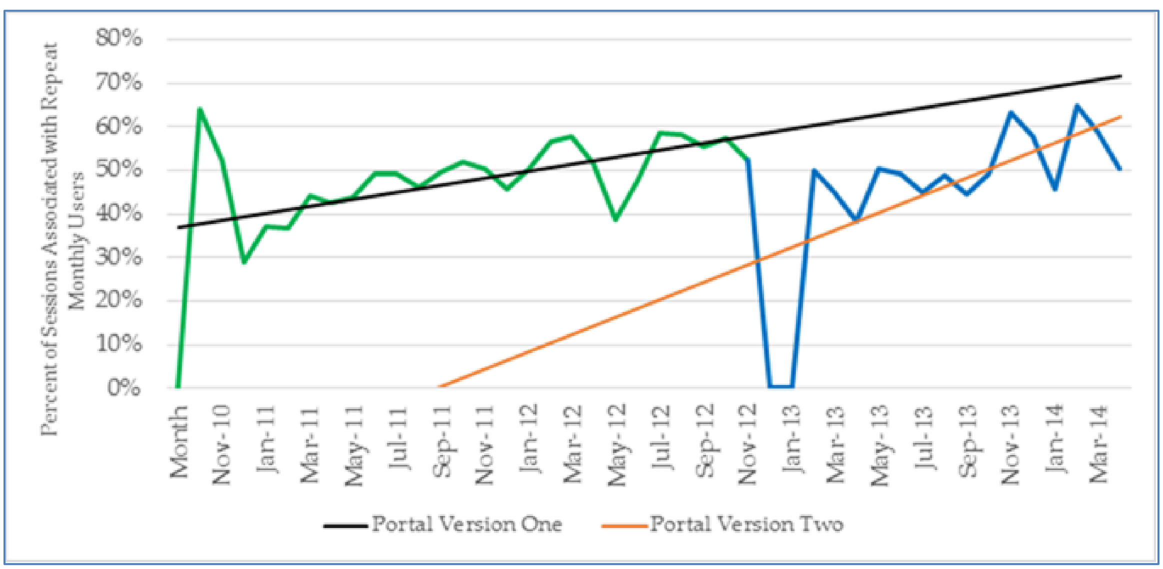
Figure 3-120: Number of HEMP Page Views



Source: Navigant analysis of Google Analytics data

In order to better understand how customers were using the portal over time, it was important to investigate the data from repeat users. By focusing on repeat users, KCP&L could essentially remove the usage peaks associated from the initial customer enrollment sessions. Figure 3-121 below shows the percentage of portal sessions that involved customers who logged in more than once per month. According to Navigant's analysis of the Google Analytics data, 49% of the first portal version's sessions were from repeat users; 57% of the second version's sessions were from repeat users. Navigant also plotted trend lines for each version of the portal. These lines show that the percentage of repeat monthly users increased over time for both versions of the portal. Additionally, Navigant deduced that the second version trend line increased at a faster rate, implying that "the second version of the site is more engaging to users."

Figure 3-121: Percent of Sessions Involving Repeat Monthly Visitors



Source: Navigant analysis of Google Analytics data

3.4.7.1.2.3 Program Technical Results

Based on the Navigant survey data, 53% of HEMP customers report that the portal helped them to better understand the actions required to reduce energy usage and save money. In terms of the actual data analysis, however, EPRI wasn't able to find any statistically significant impacts of using the HEMP.

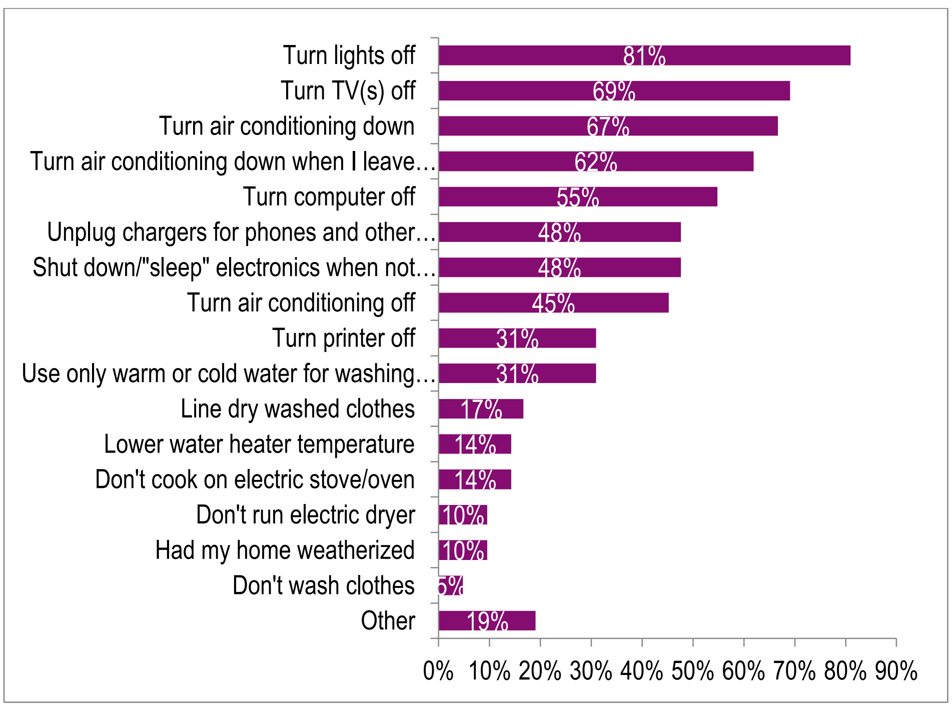
3.4.7.1.2.4 Customer Experience

During the spring of 2014, Navigant asked the HEMP customers to complete an online survey about their experience using the portal; 71 respondents began the survey and 49 respondents completed the survey.

According to the survey results, most portal users learned about the program from the KCP&L website (48%), an email from KCP&L (33%), or a mailing from KCP&L (20%). Respondents reported that the primary reasons for using the portal were taking control of energy use (49%) and saving money (31%).

A majority of respondents (53%) think that using the portal has helped them understand how to reduce electricity usage and save money, and 45% of respondents agreed that the portal influenced their decision to take steps to save energy in their home over the previous 12 months. Some of the actions taken include turning off lights (81%), turning off TVs (69%), and turning down the air conditioning (67%). The complete results to this question are shown in Figure 3-122 below.

Figure 3-122: Respondent Actions Over Past 12 Months to Save Energy in the Home



Note: n = 42

Source: Navigant analysis of survey response data

Although 48% of survey respondents reported that their portal use has remained consistent over time, 36% admit that their portal use has decreased. This was consistent with web use analysis results. The portal sessions and page views generally trended with portal registrations — showing that spikes in page views occurred when new users visited the site upon registration.

For a full version of the Navigant customer survey results, see Appendix R.

3.4.7.1.2.5 Issues and Corrective Actions

The following issues and corrective action were encountered during the performance of the Historical Interval Usage Information operational demonstration and analysis.

Table 3-85: Issues and Corrective Actions

Issue	Corrective Action
• Initial customer focus groups' feedback was that presentment of 15-minute data would be too detailed.	• Limited the portal energy usage display drill-down functionality to hourly information.
• New accounts had to be created every time a customer moved to a new residence, thus resulting in the loss of historical usage data from the customer's new account.	• This was an architectural problem with the vendor, as customer portal accounts in the HEMP were created from a concatenation of customer Account ID (specific customer) and Service Point ID (specific location). As a result, no resolution was feasible.
• Data "spikes" appeared in the portal after meter exchanges because the new meter reads would be on a different order of magnitude from the previous meter.	• Tendril's platform was designed to utilize register reads as opposed to interval reads, so there was no real solution to this problem. The SmartGrid Support Team was briefed on the issue in case they received customer calls after a meter exchange.

3.4.7.1.3 Findings

The results obtained in the execution and analyses of Historical Interval Usage Information operational demonstration are summarized in the sections below.

3.4.7.1.3.1 Discussion

KCP&L's SGDP has provided significant insight about deploying a customer Home Energy Management Portal.

Based on the Navigant customer survey, it is clear that customers signed up for HEMP accounts to help understand and control their energy use. This motive influenced which portal pages customers found most useful and visited most frequently.

Despite high overall satisfaction ratings, HEMP users admitted that they didn't visit the portal with much frequency. Based on the Google Analytics enrollment and usage data, it is clear that continued marketing to HEMP users is necessary to encourage portal usage over time.

Lastly, although customers expressed a desire to save money on energy via portal use, data analysis did not show any significant difference when comparing portal users to nonusers.

3.4.7.1.3.2 Expectations vs. Actuals

The following table provides a comparison of the Expected Results and the Actual Outcomes for the Historical Interval Usage Information operational demonstration.

Table 3-86: Expected Results vs. Actual Outcomes

Expected Results	Actual Outcome
• Customers will better understand their total energy consumption and patterns.	• In general, participating customers found that the portal was beneficial in understanding their energy consumption and patterns. According to the Navigant survey, 53% of respondents agreed with the statement, "After using the MySmart Portal, I better understand the types of actions I need to take to reduce my electricity usage and save money."
• HEMP users will find the Bill to Date and Estimated Bill information useful in managing their energy costs.	• Bill to Date and Estimated Bill information were both shown on the Dashboard/Home Page. According to survey results, 64% of respondents thought that this page of the portal was useful.
• HEMP users will reduce their overall energy consumption. Other studies have shown 1-5% reduction possible.	• EPRI's analysis of HEMP users vs. the control group could not confirm any statistically significant change in energy consumption from using the HEMP.

3.4.7.1.3.3 Computational Tool Factors

The following table lists the values derived from the Historical Interval Usage Information operational demonstration that will be used as inputs to the SmartGrid Computational Tool.

Table 3-87: Computational Tool Values

Name	Description	Calculated Value
Reduced Total Residential Electricity Cost ($)	Changes in usage can result in reductions in the total cost of electricity.	$ 0

3.4.7.1.4 Lessons Learned

Throughout the conduct of the operational testing and analysis of the Historical Interval Usage Information function, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- Despite rolling out the portal with the AMI implementation and IHD deployments, customers didn't associate the HEMP with the SGDP.
- When a new customer portal is deployed, it needs to have at least the features that were in the existing portal (AccountLink). Based on survey responses, it was clear that customers had grown accustomed to downloading their usage data, viewing their data in a tabular format, and seeing the weather overlaid in the system — all capabilities that they formerly had in AccountLink. When the Tendril HEMP was deployed, there were a number of complaints as customers tried to find these capabilities in the new portal.
- Customers weren't as interested in the social aspects of the portal as KCP&L anticipated. Setting goals, interacting with energy experts, and earning points did not appeal to customers. Rather, customers focused their portal sessions on usage and billing data. Different messaging to different customer groups should be explored to maximize continued usage of the HEMP over time.
- Customer portal usage was not strong over time. The portal deployment should have ongoing, proactive marketing to encourage ongoing portal usage by existing users.
- Tendril's platform utilized register reads, but interval data would be preferred moving forward. With interval reads, data presentation has no dependence on the relationship between reads over time. However, processing register reads can lead to issues in the event of meter exchanges, as significant changes in the order of magnitude between two consecutive reads can cause abnormalities in data presentation.
- KCP&L loaded two years of historical AMR data and created a process to offset customers' new AMI data by a fixed value equal to their last AMR read. This allowed customers access to their historical consumption data with a seamless transition between AMR data and AMI data. However, this also caused data presentation issues any time a customer had a meter exchange — the offset only accounted for the last AMR read and did not account for the last AMI read of any interim AMI meters.
- Since HEMP accounts were associated with a specific customer at a specific location, historical customer usage data did not carry over when customers moved to new locations in the project area. High turnover in the project area led to an exorbitant number of unused accounts that were not deleted after the customers moved out. Ideally, HEMP accounts would be tied to a specific customer (not location) moving forward.
- Tendril's platform does not currently support net metering. Negative usage data (-kWh) was not displayed properly in the portal. Thus, customers with net metering did not have the same experience as those without.
- One version of the portal was used for the first half of the project and another version was used for the second half of the project. The second version was launched before it was fully functional, leading to confusion and frustration from customers. For future deployments, thorough testing would help to make the roll-out process smoother.

3.4.7.2 In-Home Display

In-Home Display is a demonstration of one aspect of the Customer Electricity Use Optimization function.

3.4.7.2.1 *Overview*

The following sections provide an overview of the operational, demonstration, testing, and evaluation methodology used for the In-Home Display operational demonstration.

3.4.7.2.1.1 Description

All customers in the SGDP were offered, at no cost, an In-Home Display. The program was marketed as the MySmart Display. This IHD is a portable, digital display device that communicates with a customer's AMI meter via ZigBee and provides real-time energy usage monitoring. This enabled customers to gain improved awareness and thus better manage their personal energy usage and associated costs. The IHD essentially provides customers with a real-time "speedometer" and "odometer" for electric use in their home – giving them both current consumption rate information and the ability to visualize historical usage information.

The IHD provided customers with:

- Real-time energy usage and cost information from the customer's smart meter.
- Current price of energy based on the customer's rate, current usage block, and/or TOU period.
- Daily bill update that provides Bill to Date, days remaining in billing period, and an Estimated Bill Projection based on current consumption patterns.
- Demand Response messages asking the customer to reduce load during peak times.
- Other Informational messages sent from the utility.

3.4.7.2.1.2 Expected Results

With the additional information that the IHD provides the consumer, it was expected that:

- Customers would use the real-time metering data available on the IHD to better understand their total energy consumption patterns and those of individual appliances.
- Customers would find the Bill to Date and Estimated Bill information provided on the IHD useful in managing the energy usage costs.
- IHD users would reduce their overall energy consumption. Other studies have shown that IHD users may reduce their overall energy consumption by as much as 2-7%.
- IHD user may voluntarily participate in DR events when notified via the IHD.

3.4.7.2.1.3 Benefit Analysis Method/Factors

The DOE SGCT was used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits were quantified.

- Reduced Electricity Costs

Benefits were calculated using SGCT formulas. The following factors were measured, projected or calculated during the application operation and/or demonstration.

Reduced Electricity Costs (Consumer)

- Reduced Total Residential Electricity Cost ($).

3.4.7.2.1.4 Testing Methodology

The following points provide an overview of how the operational demonstration and testing for this application was accomplished:

- Load data, at 15-minute intervals, was collected for all IHD participants throughout the project period through KCP&L's AMI system deployed as part of the project.
- All interval meter data was stored in KCP&L's MDM and DMAT systems.
- At the conclusion of the operational period, IHD participants' interval and aggregate usage data was compared to the coincident control group interval and aggregate usage data.

3.4.7.2.1.5 Analytical Methodology

The following points provide an overview of the analytical methods that were used to evaluate the impact and benefits of this application:

- Load data, at 15-minute intervals, for the control group and IHD participants was extracted from KCP&L's DMAT for analysis.
- Load profiles of IHD participants were compared to those of select control group customers on an hourly, daily, and monthly basis to evaluate the average or typical impact IHD exhibits on measured participant energy usage. Calculated impacts were assessed for statistical significance.
- Willing IHD participants were surveyed by a third party to solicit feedback on their experience using the IHD to determine their primary application of the tool and information provided.

3.4.7.2.2 Plan Execution and Analysis

The following sections provide details regarding the functional tests performed, data collected, and analysis performed for the In-Home Display operational test.

3.4.7.2.2.1 Functionality Deployed

The In-Home Display program was offered to KCP&L customers starting in the fall of 2010, coinciding with the AMI implementation and the HEMP deployment. The IHD receives direct information from the smart meter and presents data to the customer to aid in monitoring real-time energy usage. The customer can get some of the information offered by the web portal, but the customer doesn't have to log into a portal. The IHD can be located in the home for convenient and frequent access. A picture of the IHD is shown below in Figure 3-123.

The IHD receives real-time demand (kW) and consumption (kWh) data directly from the AMI meter. The IHD processes this information, along with pricing signals from the meter, to give customers an accurate real-time estimate of cost and consumption for the present day as well the previous day.

A special process was created to estimate the customer billing information with accurate taxes and fees based on the customer's current rate. The bill estimate provides and end-of-bill-cycle projected bill based on usage-to-date in a given billing cycle. These estimated bill "true-up" messages are sent to the customer's IHD on a daily basis.

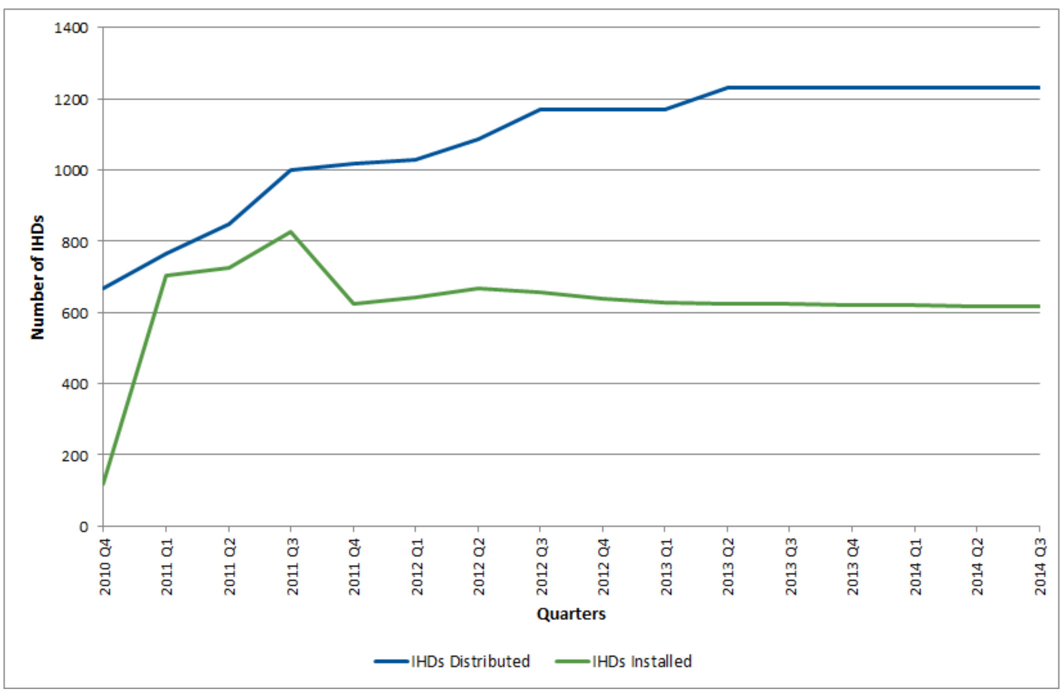
Pricing signals based on customer rates are sent to the IHD via the AMI network. Customers can then see their real-time energy price and accumulated daily costs. A special event pricing signal was required to support TOU rates. Sent on a daily basis, TOU event pricing signals are sent to trigger a peak-price change from 3 to 7 PM.

Figure 3-123: IHD Main Screen

3.4.7.2.2.2 Program Participation

Customers with SmartGrid AMI meters were eligible to participate in the MySmart Display program. Participants received an IHD, which communicated with their AMI meter to present real-time data to the customer about energy usage. Throughout the duration of the program, the IHDs were available to approximately 12,000 customers, and 1,231 IHDs were distributed to customers. At the peak of the program, there were 828 customers with IHDs installed. Figure 3-124 below shows the customers with IHDs from the inception through the completion of the program. As shown, the participants dropped from Q3 2011 to Q4 2011 as KCP&L wrote off devices that were no longer communicating with meters. Many IHDs were considered "lost" as the meters were unable to communicate with the IHDs and the customers could not be contacted. This was due to a variety of issues, such as meter exchanges, move-outs, and many devices that had been powered-off or "put in the drawer" due to the communications issues. Additionally, customers with an IHD were not eligible to participate in the standalone PCT or HAN programs, so some IHD participants turned in their IHDs for standalone PCTs or HANs when the latter two programs became available.

Figure 3-124: IHD Participants Over Time

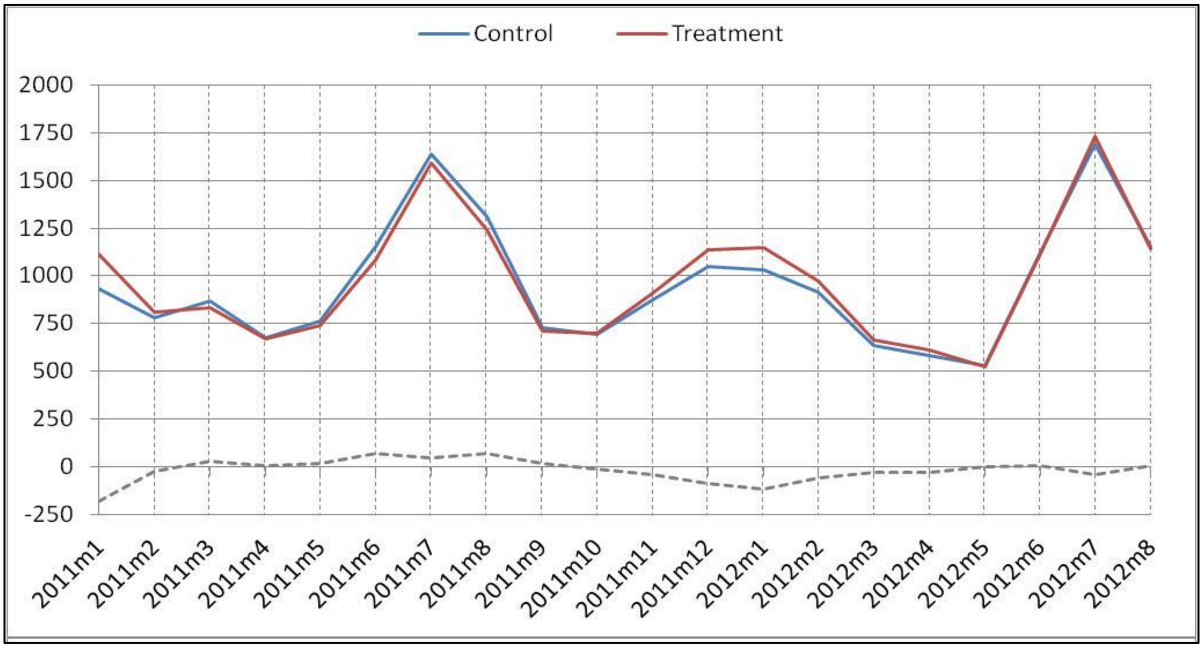


3.4.7.2.2.3 Program Technical Results

Based on the Navigant survey data, 70% of IHD users expected to save an average of $30 on their monthly energy bills by using IHDs at the onset of the program. After using an IHD, 56% of respondents said that they noticed a reduction in their energy bills, and these people claimed an average reduction of $40 per month.

For the EPRI analysis, IHD customers were matched with control group customers for comparison. Based on the 466 customers with IHDs and the matched control group, the difference in monthly usage between customers who had IHDs and those who did not was quite small. Due to this small sample size, any aggregate energy savings (or losses) caused by the IHDs are not statistically measurable in this sample.

Figure 3-125: Average Usage by Month for IHD and Control Customers



3.4.7.2.2.4 Customer Experience

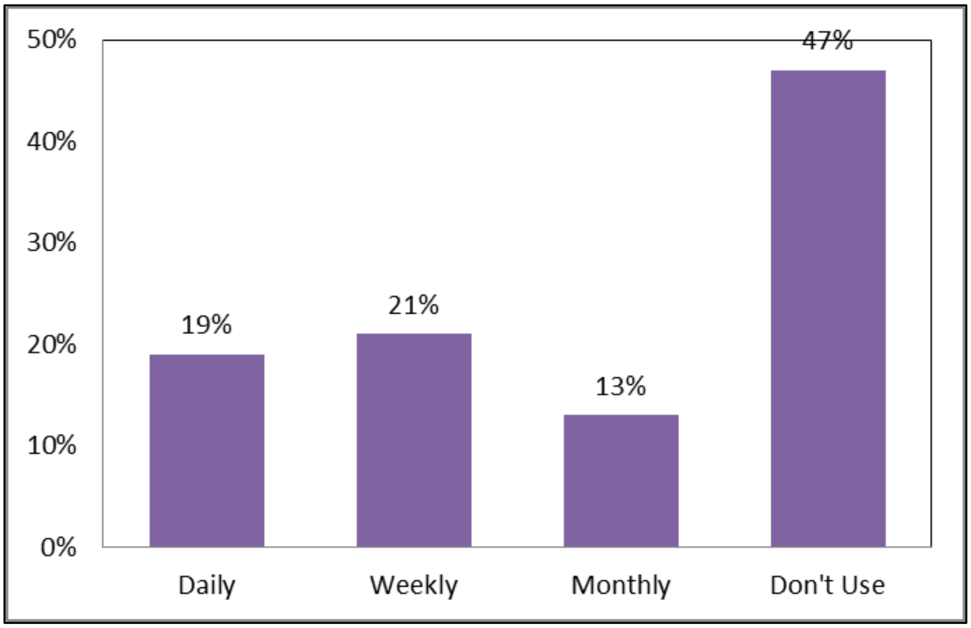
In 2012, the MySmart Display (IHD) participants were contacted to participate in a phone survey; 72 respondents completed the survey. Although the IHD program continued through 2014, KCP&L decided not to duplicate the survey in 2014, as the program didn't change significantly since the 2012 survey.

Unlike the HEMP survey responses, the IHD participants had a strong awareness about the overall SGDP; 74% of respondents were aware of the project as a whole.

IHD participants learned about the program from a variety of sources, namely community events (28%), mailed brochures (19%), and community groups (17%). Respondents reported that the primary reasons for requesting a device were for better control of their energy use (65%) and saving money on their electricity bills (24%).

Customers that had an IHD installed in their home reported varying frequencies of use; 47% of survey respondents admitted that they didn't use the display at all. Customers who did use their IHD varied in frequency, from daily to once a month. Figure 3-126 below shows the frequency that participants used their IHDs at the time of the survey.

Figure 3-126: Frequency of IHD Usage



Note: n = 135

Source: Navigant analysis of survey response data

Participants that expected to save money by using the IHDs expected to save $30 per month. For respondents who noticed a reduction in their energy bills, they reported an average savings of $40 per month, which was more than had been anticipated.

In general, respondents found the various features of the IHD very useful. At least 50% of respondents thought the following features were "very useful": Daily Cost (60%), Daily Consumption (61%), Estimated Bill (57%), and Billing Detail (50%).

Also, 89% of respondents reported taking additional energy savings actions based on their IHD use. Some of the additional actions taken included turning lights off (53%), unplugging device chargers (19%), weatherizing their home (14%), turning off the TV (14%), installing CFL lightbulbs (11%), and turning down the air conditioner (10%).

At the time that the survey was conducted (in 2012), 87% of respondents still had their IHD installed in their home. Those that no longer had the devices installed attributed this to the device breaking (35%) or the device never working in the first place (22%).

For a full version of the Navigant customer survey results, see Appendix R.

3.4.7.2.2.5 Issues and Corrective Actions

The following issues and corrective action were encountered during the performance of the In-Home Display operational testing and analysis.

Table 3-88: Issues and Corrective Actions

Issue	Corrective Action
• IHD operational testing and analysis period ended prior to DR event testing and analysis.	• KCP&L did not include DR messaging to IHDs in any DR events.
• IHDs didn't communicate properly to the AHE during the device provisioning process, and KCP&L couldn't determine whether IHDs were plugged in by the customer during install.	• Installers worked to troubleshoot these issues on a case-by-case basis.
• During the IHD deployment, a firmware issue was discovered that modified the IHD screen contrast, rendering the screen unreadable.	• The current inventory of IHDs was returned to Tendril and KCP&L received a new shipment of IHDs with a newer firmware version containing a fix for this bug. The previously deployed IHDs were replaced, one by one, as the affected customers contacted KCP&L to report the issue.
• The Tendril platform did not initially support block rates, including the KCP&L standard residential declining-block rate, so pricing changes were not automatically triggered to the IHDs when the customer moved into a new usage block within the rate.	• The short-term fix for this issue involved sending the correct price to the IHD on a daily basis, in order to pick up any rate changes that may have gone into effect on the previous day (i.e., the customer moved into the next usage block of the rate on the previous day). • This issue was resolved in the long term when Tendril included support for block rates in the first platform upgrade.

3.4.7.2.3 Findings

The results obtained in the execution and analyses of In-Home Display operational analysis are summarized in the sections below.

3.4.7.2.3.1 Discussion

Throughout the IHD program deployment and operational period, KCP&L has gained many insights about how to manage this type of customer-facing implementation.

One of the main takeaways was that a device like this needs to be installed and immediately useful in order for the customer to have any long-term engagement potential. The customers that received the IHDs prior to the AMI meters were not able to do anything with the device, and many of them failed to use the IHDs at all, even when the devices became functional.

Customers that did use the IHDs really liked the Estimated Bill feature, especially because KCP&L considered the added taxes and fees in the number presented on the IHD. Of customers that used the IHD, 89% also took other energy-saving actions based on their IHD use. This shows that the IHDs heightened awareness of energy usage.

Lastly, customers expressed a desire to save money on energy via IHD use, and those that noticed a difference reported an average savings of $40 per month. When the actual data was analyzed comparing IHD users to the control group, however, no statistically significant savings were found.

3.4.7.2.3.2 Expectations vs. Actuals

The following table provides a comparison of the Expected Results and the Actual Outcomes for the In-Home Display operational test.

Table 3-89: Expected Results vs. Actual Outcomes

Expected Results	Actual Outcome
• Customers will use the IHD to better understand their total energy consumption patterns and those of individual appliances.	• Although 47% of survey respondents said that they didn't use the IHD at all, the people that did use it found it beneficial in understanding total energy consumption patterns and those of individual appliances. Among IHD users, 53% said that they feel like they had more control (likely in part due to better understanding) of their energy use; 89% of IHD users reported that they took additional energy-saving actions after they started using the device. Many of these users turned down/off specific devices and appliances based on their use of the IHD.
• IHD users will find the Bill to Date and Estimated Bill information useful in managing their energy costs.	• According to survey results, 83% of respondents reported that the Billing Detail feature was useful. • According to survey results, 85% of respondents reported that the Estimated Bill feature was useful.
• IHD users will reduce their overall energy consumption. Other studies have shown 2-7% reduction possible.	• According to survey results, 56% of IHD users noticed a reduction in their energy bills, with respondents noting an average savings of $40 per month. • EPRI's analysis of IHD users vs. the control group could not confirm any statistically significant change in energy consumption from using the IHD, however.
• IHD users will voluntarily participate in DR events when notified via the IHD.	• Due to differences in operational test periods, KCP&L did not evaluate DR event participation by IHD participants.

3.4.7.2.3.3 Computational Tool Factors

The following table lists the values derived from the In-Home Display operational test analysis that will be used as inputs to the SmartGrid Computational Tool.

Table 3-90: Computational Tool Values

Name	Description	Calculated Value
Reduced Total Residential Electricity Cost ($)	Changes in usage can result in reductions in the total cost of electricity.	$ 0

3.4.7.2.4 Lessons Learned

Throughout the conduct of the operational testing and analysis of the In-Home Display, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- Tendril's IHD does not currently support net metering. Negative usage data (-kWh) was not displayed properly on the IHDs. Thus, customers with net metering did not have the same experience as non-net metered customers.
- Many of the IHDs were distributed when customers signed up to participate in the SGDP, prior to the AMI meter installation. As a result, the IHDs were useless upon install. In hindsight, a better strategy would have been to wait to deploy the IHDs when the meters were installed, so that the customer would have a functioning piece of technology immediately upon completion. This would have also been an ideal time for any troubleshooting or customer education from the installer.
- The IHD provisioning process relied heavily on the customer contacting KCP&L support to pair the IHD to the meter. This was problematic and would have been easier for a professional installer to complete.
- IHD device reliability and persistent connectivity issues negatively affected ongoing customer participation.

3.4.7.3 Home Area Network

Home Area Network is a demonstration of one aspect of the Customer Electricity Use Optimization function.

3.4.7.3.1 Overview

The following sections provide an overview of the operational, demonstration, testing, and evaluation methodology used for the Home Area Network operational demonstration.

3.4.7.3.1.1 Description

All customers in the SGDP that met program criteria were offered, at no cost, a Home Area Network. In order to participate in this program, customers were required to have an AMI meter, central air conditioning, and Wi-Fi in the house. Additionally, they couldn't be a participant in KCP&L's existing residential thermostat program. Fitting the criteria would allow a customer to be enrolled in the HAN program. The HAN consisted of a broadband gateway device communicating to the KCP&L meter and to numerous energy devices in the customer's home. Program participants received a compatible programmable communicating thermostat and two compatible load control switches. The PCT was enrolled in the pilot utility demand response program.

The gateway device received real-time usage information directly from the customer's smart meter and established communications between the utility HEMP via the customer supplied internet connection. The combination of HEMP/HAN functionality provided customers:

- With a user-friendly visualization of real-time usage data from their smart meter via the HEMP and enabled making energy-usage decisions based on real-time usage and cost information.
- The ability to remotely control their PCT and other energy consuming appliances via the load control switch(es) to manage daily energy consumption.
- The ability for all HAN-connected devices to participate in demand-response events based on customer preferences.

While the HAN is the main focus of this section, it is important to note that customers without residential Wi-Fi were eligible to participate in a different program, the stand-alone PCT program.

3.4.7.3.1.2 Expected Results

With the additional control and information that the HAN provides the consumer, it was expected that:

- Customers would use the information on the HEMP to better understand their total energy consumption and patterns.
- HAN users would use the device communications and control provided via the HAN to manage their energy-consuming devices.
- HAN users would use the information and control provided via the HEMP to be effective in managing their energy usage costs.

For those that choose to combine HAN control capabilities with new voluntary TOU rate options, it was expected that the HAN users would:

- Shift load to Off-Peak times.
- Voluntarily allow HAN-connected devices to participate in DR events.

Additionally, it was planned that the HAN deployments would be used to demonstrate customer-incented DR events.

3.4.7.3.1.3 Benefit Analysis Method/Factors

The DOE SGCT was used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits were quantified.

- Deferred Generation Capacity Investments
- Reduced Electricity Costs

Benefits were calculated using SGCT formulas. The following factors were measured, projected or calculated during the application operation and/or demonstration.

Deferred Generation Capacity Investments

- Reduced Customer Load at Annual Peak Time (MW)

Reduced Electricity Costs (Consumer)

- Reduced Total Residential Electricity Cost ($).

3.4.7.3.1.4 Testing Methodology

The following points provide an overview of how the operational demonstration and testing for this application was accomplished:

- Interval load data, in 15-minute intervals, was collected for all HAN participants throughout the project period through KCP&L's AMI system deployed as part of the project.
- All interval meter data was stored in KCP&L's MDM and DMAT systems.
- At the conclusion of the operational period, HAN participants' interval and aggregate usage data was compared to coincident control group interval and aggregate usage data.

3.4.7.3.1.5 Analytical Methodology

The following points provide an overview of the analytical methods that were used to evaluate the impact and benefits of this application:

- Interval load data, in 15-minute intervals, for the control group and HAN participants was extracted from KCP&L's DMAT for analysis.
- Load profiles of HAN participants were compared to those of select control group customers on an hourly, daily, and monthly basis to evaluate the average or typical impact the HAN exhibits on measured participant energy usage. Calculated impacts were assessed for statistical significance.
- Willing HAN participants were surveyed by a third party to solicit feedback on their experience using the HAN to determine their primary application of the tool and information provided.

3.4.7.3.2 Plan Execution and Analysis

The following sections provide details regarding the functional tests performed, data collected, and analysis performed for the Home Area Network operational test.

3.4.7.3.2.1 Functionality Deployed

The HAN consisted of a broadband-connected HAN gateway that interfaced directly with the HEMP servers, one or two PCTs depending on the customer's HVAC configuration and compatibility, two 120V LCSs and an optional 240V LCS if the customer had a compatible load (e.g., pool pump, electric water heater, etc.). The HAN devices are shown in Figure 3-127.

Figure 3-127: Home Area Network Devices

The gateway within the HAN communicated with the HEMP via the customer-supplied Internet connection, enabling customers to manage energy consumption in their home. The gateway device received real-time usage information directly from the customer's AMI meter. This usage information was passed to the HEMP to be displayed to the customer. The gateway also transferred control commands from the HEMP to the PCT and LCSs. This enabled customers to remotely manage device schedules and rules, control devices, and manage demand-response event participation.

The PCT within the HAN allowed customers to set schedules for their heating and cooling needs throughout the week. Customers could set four different temperature set points for both heating and cooling throughout each day of the week. This helped customers better manage their heating/cooling loads when they were away from their homes. The PCT also included different temperature modes, such as "Hold" and "Vacation," which offered customers more flexibility in managing their consumption.

Pricing signals were sent from KCP&L's billing system to the HEMP based on the customers' rate codes. These pricing signals were pulled from the HEMP by the HAN gateway rather than through the metering network and were displayed on the PCT. Customers were able to see real-time pricing information on the screen of the PCT to make energy-conserving decisions when programming the temperature set point and schedule.

The LCSs within the HAN allowed customers to set pricing rules for the simple loads attached to the LCSs. This enabled the device to respond to, and operate in conjunction with, changes in electricity rates automatically, thus giving the customers added flexibility to help manage energy consumption and costs. The LCSs also reported individual device consumption data to the HEMP to be displayed to customers. This feature enabled customers to better understand the energy consumption and operating costs of individual appliances within their homes.

Program participants could enroll their HAN devices in the SmartGrid demand response program. Originally, both the PCTs and LCSs were planned for use in demand response events, but due to technical and regulatory constraints only the PCTs were included in the direct load control program. When a demand-response event occurred, customers were notified ahead of time with information about the event start time and duration. By default, customers were opted into each event. However, once customers received the event they could opt out or back in at any time before the event concluded. Customers could make this decision — opt in, or opt out — at the PCT or the HEMP.

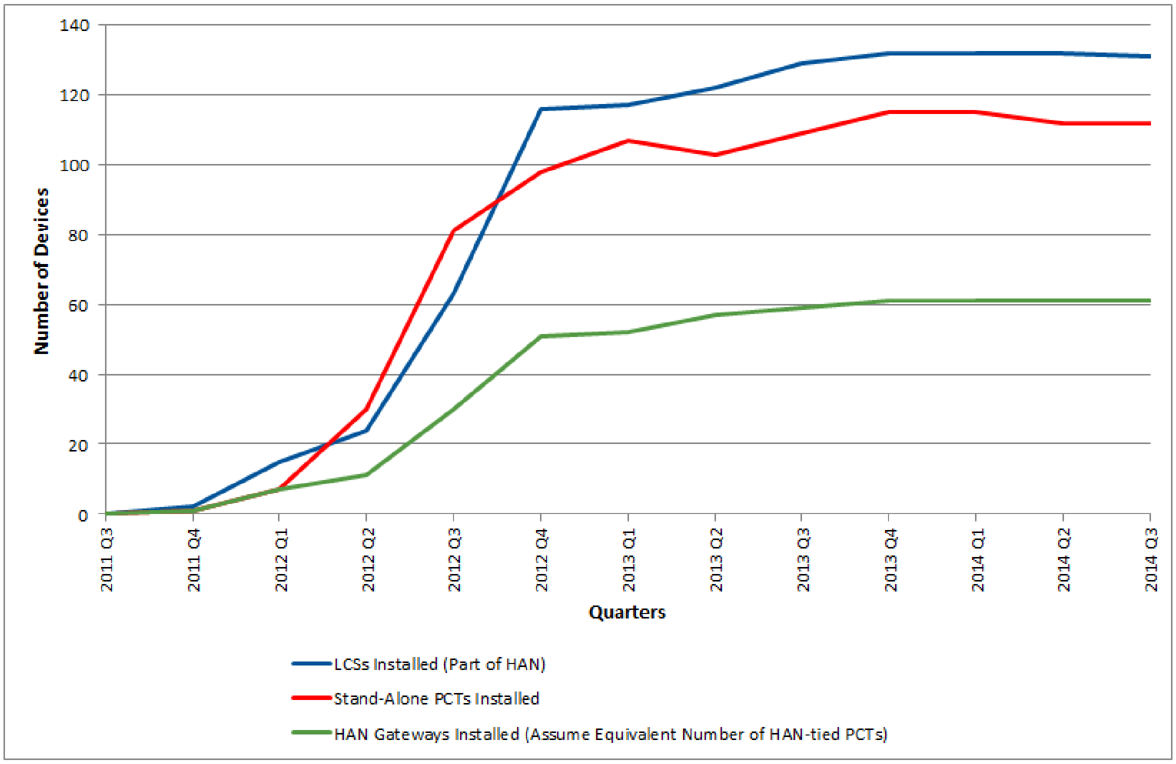
3.4.7.3.2.2 Program Participation

Customers with SmartGrid AMI meters, central air conditioning, and Wi-Fi in their homes were eligible to receive a Home Area Network – a collection of in-home energy devices networked together. Participants of the HAN program received a HAN gateway, a PCT, and two LCSs. At the peak of the program there were 61 customers with active HANs. Since each customer with a HAN gateway also had a HAN-connected PCT, this meant that there were also 61 PCTs that were part of a HAN. There were 132 LCSs associated with these 61 Home Area Networks.

Customers that didn't have residential Wi-Fi were still eligible to participate in a SmartGrid demand response program, but they weren't eligible for a HAN. Instead, they were offered a stand-alone PCT. At its peak, there were 115 customers enrolled in the stand-alone PCT program.

Figure 3-128 below shows the participation in the SmartGrid HAN and stand-alone PCT programs from inception through the completion of the programs.

Figure 3-128: HAN and Stand-Alone PCT Participants Over Time



3.4.7.3.2.3 Program Technical Results

EPRI analysis didn't find any statistically significant impacts of using the HAN when HAN customers were compared to the control group. When looking outside the HAN program to the stand-alone PCT program, however, eight (8) survey respondents, or 23%, reported that they had saved money on their monthly bill.

3.4.7.3.2.4 Customer Experience

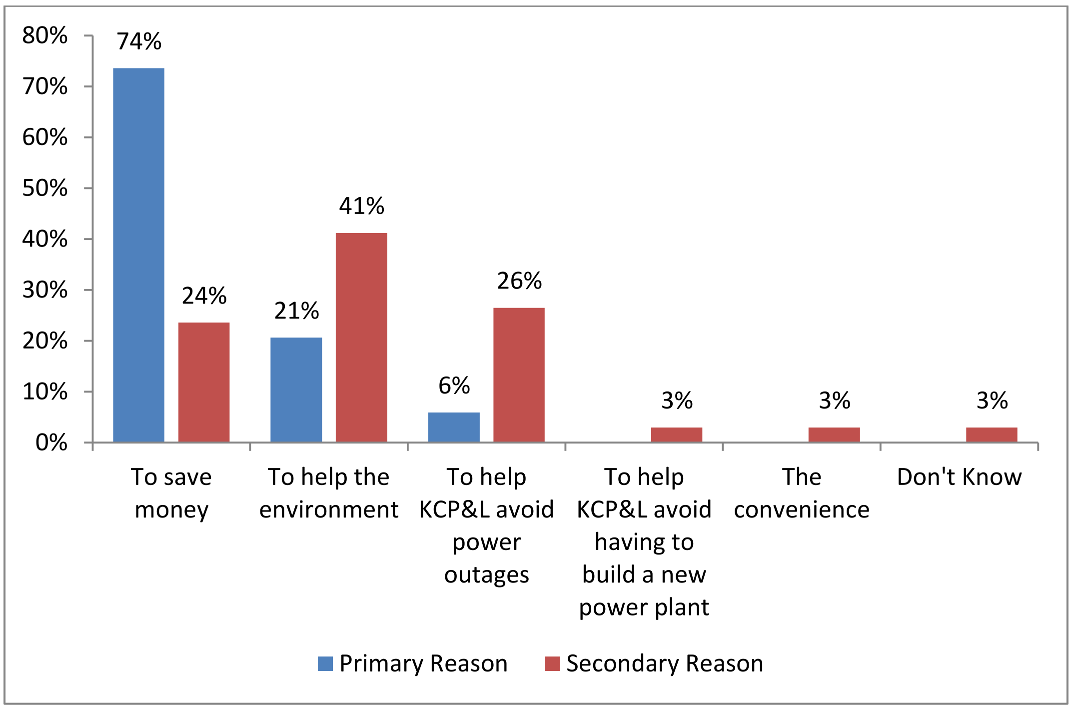
During the fall of 2014, Navigant contacted stand-alone thermostat and HAN participants for a phone survey. Of the 34 people that completed the survey, seven (7) had HAN devices. The results described in this section apply to both the HAN and stand-alone PCT programs, and to the residential demand response events tied to these programs.

Originally, KCP&L planned to conduct direct load control events to the stand-alone PCTs and Pay for Participation (PFP) events to the HAN devices. The DLC events would use utility-owned communications infrastructure, and would thus be more reliable. For these events, KCP&L would specify how each thermostat was to change behavior during a DR event – the thermostat would be set back by 2 degrees. The PFP events were to be directed towards the HAN devices (PCTs and LCSs), and they would rely on each customer's Internet connection. For these events, KCP&L would send high/medium/low criticality signals to the HANs, and each HAN would respond based upon predefined customer preferences. The

PFP events were not implemented, however, since the HEMP didn't develop the required technical capabilities and the necessary tariffs were not created for this new program. As a result, KCP&L used the HAN-tied PCTs in the DLC events planned for the stand-alone PCTs. The HAN-connected LCSs were not utilized for DR events during the demonstration, but they were still functional for the customers as part of their HANs.

In terms of survey results, 64% of the stand-alone thermostat and HAN participants were familiar with the overall SGDP. Thermostat and HAN participants learned about the programs from material in the mail (65%) and through door-to-door recruiting (18%). Respondents reported that the primary reasons for requesting devices were to save money (74%) and to help the environment (21%). See Figure 3-129 below for comprehensive results describing motivation for enrolling in the DR programs.

Figure 3-129: Customer Drivers for Enrollment in Stand-Alone PCT and HAN Programs



Note: n = 34
Source: Navigant analysis of survey response data

Although 64% of respondents were familiar with the SGDP, 59% admitted that they had never visited the HEMP. Thus, and unfortunately, customers didn't tie all of the program components together for maximum optimization.

KCP&L called a total of nine (9) DR events throughout the summer of 2014. While each DR event didn't go to all of the survey respondents, each respondent was called upon for at least half of the DR events. Despite this, only 31% of respondents could recall one or more events. Depending on the program intent, this could be a good or a bad result. If the intent was to engage the customers to modify their behaviors during the event, then this survey result would be undesirable. For KCP&L, however, the intent was to have *minimal impact* on the customer – ideally, the thermostat would be set back by 2 degrees for the two-hour event, and the customer wouldn't even notice. Based on survey results, it appears that the program did this successfully.

For a full version of the Navigant customer survey results, see Appendix R.

3.4.7.3.2.5 Issues and Corrective Actions

The following issues and corrective action were encountered during the performance of the Home Area Network operational testing and analysis.

Table 3-91: Issues and Corrective Actions

Issue	Corrective Action
• There were very few electric water heaters in the demonstration area.	• HAN participants were restricted to managing their thermostat loads.
• There was a low penetration of central air conditioning in the demonstration area.	• KCP&L adjusted MySmart HAN program participation expectations due to the limited candidate pool.
• Meter exchanges resulted in issues with HAN device association.	• To get the same device provisioned to the new meter, the device(s) were manually cleaned from the AMI database whenever meters were exchanged. This reallocated the device(s) within the AHE database to be provisioned to the new meter.
• Bugs and functionality issues surfaced with the HAN devices during the second HEMP platform upgrade.	• Device firmware was upgraded on all HAN devices via the broadband connection.
• Many HAN devices were joined improperly or didn't join to the network at all during the device installation and provisioning process.	• A successful HAN installation process required coordination between the device installer and the customer service representatives. When the steps weren't followed exactly, the devices weren't properly joined. Typically, this required resetting the SmartMeter HAN and restarting the provisioning process again. Occasionally, the devices had to be replaced all together.
• Many HAN devices were not reachable during DR events due to customer broadband connectivity issues.	• KCP&L could only call on reachable HAN devices during DR events. The stand-alone PCTs were more reliable for DR events, because they only utilized the AMI backhaul used for DR messaging.

3.4.7.3.3 Findings

The results obtained in the execution and analyses of Home Area Network operational analysis are summarized in the sections below.

3.4.7.3.3.1 Discussion

Throughout the HAN program deployment and operational period, KCP&L gained numerous insights about this type of technology and how to make it most useful to customers.

Some of the main limitations of HAN enrollment had to do with the requirements for participation: Wi-Fi in the home and central air conditioning. Even when customers met both of these requirements, most didn't have any 240V loads in their home to connect the LCSs to. These shortcomings significantly limited participation in the HAN program.

Proper installation and provisioning of the HAN devices was critical in order for the HAN to be useful. When the steps weren't performed in the correct order, the provisioning process had to be repeated.

Even if the HAN was set up successfully, problems with the customer's broadband frequently made the HAN devices unreachable.

Among HAN and stand-alone PCT program participants, 74% signed up for the devices to save money. Despite this motivation, no statistically significant reduction in energy costs was found when comparing these participants to those in the control group.

3.4.7.3.3.2 Expectations vs. Actuals

The following table provides a comparison of the Expected Results and the Actual Outcomes for the Home Area Network operational test.

Table 3-92: Expected Results vs. Actual Outcomes

Expected Results	Actual Outcome
• Customers will use the information on the HEMP to better understand their total energy consumption patterns.	• Engaged HAN participants were able to use the HEMP to see real-time information about their PCT as well as the loads plugged into their LCSs. For example, they could use the Volt switch (120-V LCS) to monitor usage of their pluggable devices.
• HAN users will use the device communications and control provided by the HAN to manage their energy-consuming devices.	• HAN participants were able to control their HAN PCT and LCSs, either at the device or via the HEMP. • The most common complaint was that users wanted more training to better understand how to use the HAN.
• HAN users will use the information and control provided by the HEMP to manage their energy usage costs.	• There was a lack of 240-V devices (such as water heaters and pool pumps) in the area. As such, there were minimal savings opportunities for customers due to the LCSs. • EPRI's analysis of HAN users vs. the control group could not confirm any statistically significant change in energy consumption from using the HAN.

3.4.7.3.3.3 Computational Tool Factors

The following table lists the values derived from the In-Home Display operational test analysis that will be used as inputs to the SmartGrid Computational Tool.

Table 3-93: Computational Tool Values

Name	Description	Calculated Value
Reduced Customer Load at Annual Peak Time (MW)	The total customer peak demand for customers. This input includes any impacts from energy efficiency, demand response and any other programs or technology that result in customer electricity use optimization	0 MW
Reduced Total Residential Electricity Cost ($)	Changes in usage can result in reductions in the total cost of electricity.	$ 0

3.4.7.3.4 Lessons Learned

Throughout the conduct of the operational testing and analysis of the Home Area Network, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- HAN users want to use the HEMP to do basic configuration, but they also want to be able to monitor and control devices in their home via a phone application. Future HAN programs should explore mobile device capabilities, as this was a common suggestion of program participants.
- Broadband internet access was lower than expected among customers in the project demonstration zone, so customer enrollment and participation in the HAN program turned out to be lower than initially anticipated.
- The number of compatible HVAC systems was lower than expected among customers in the project demonstration zone, rendering customer enrollment and participation in the HAN program lower than initially anticipated. Many interested customers were disqualified from the HAN program during pre-installation screenings or in-home visits, due to such incompatibilities.
- Customer broadband connectivity issues prevented participation of many HAN PCTs in DR events. If the utility DR program is going to rely on the customers' broadband connections and Wi-Fi networks, the utility needs to implement a proactive HAN monitoring and initiate customer contact to restore HAN communications so that DR devices are available to participate in events.
- The 120V and 240V load-control devices were not differentiated within the HEMP reporting mechanism, due to both devices falling under the same ZigBee device class. This made it difficult to differentiate between these two types of devices without consulting additional customer enrollment information in another system.

3.4.7.4 Time-of-Use

Time-Of-Use is a demonstration of one aspect of the Customer Electricity Use Optimization function.

3.4.7.4.1 Overview

The following sections provide an overview of the operational, demonstration, testing, and evaluation methodology used for the Time-Of-Use operational demonstration.

3.4.7.4.1.1 Description

All Residential customers in the SGDP were offered the ability to participate in a pilot Time-of-Use rate. While designed to be revenue neutral, the pilot TOU tariff provided significant incentive for customers to shift load from On-Peak periods to Off-Peak periods due to a relatively large difference between On-Peak and Off-Peak prices during the summer months. On this pilot TOU rate, during summer months, the On-Peak energy price ($/kWh) is approximately six times greater than the Off-Peak price.

3.4.7.4.1.2 Expected Results

During the summer when the TOU rates are in effect, it was expected that TOU participants would:

- Shift load from On-Peak to Off-Peak times
- Reduce their overall kWh consumption
- Achieve an overall reduction in their electricity bill

It was also expected that some TOU participants would also participate in IHD or HAN programs and that those dual participants may achieve greater savings than participants without devices.

3.4.7.4.1.3 Benefit Analysis Method/Factors

The DOE SGCT will be used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits were quantified.

- Deferred Generation Capacity Investments
- Reduced Electricity Costs

Benefits were calculated using SGCT formulas. The following factors were measured, projected or calculated during the application operation and/or demonstration.

Deferred Generation Capacity Investments

- Reduced Customer Load at Annual Peak Time (MW)

Reduced Electricity Costs (Consumer)

- Reduced Total Residential Electricity Cost ($).

3.4.7.4.1.4 Testing Methodology

The following points provide an overview of how the operational demonstration and testing for this application was accomplished:

- 15 minute interval load data was collected for all TOU participants throughout the project period through KCP&L’s AMI system deployed as part of the Project.
- 15 minute interval load data from was collected for a HEMP control group throughout the project period using KCP&L’s AMR system deployed outside of the project area.
- All interval meter data was stored in KCP&L’s MDM and DMAT systems.
- At the conclusion of the operational period (through September 2014), TOU participants bills were compared to what their bills would have been under the standard residential declining block rates.

- At the conclusion of the operational period (through September 2014), TOU participants interval and aggregate usage data were compared to coincident control group interval and aggregate usage data.

3.4.7.4.1.5 Analytical Methodology

The following points provide an overview of the analytical methods that were used to evaluate the impact and benefits of this application:

- 15-minute interval load data for the control group and TOU participant were extracted from KCP&L's DMAT for analysis.
- Load profiles of TOU participants were compared to those of select control group customers on an hourly, daily, and monthly basis to evaluate the average or typical impact TOU exhibits on measured participant energy usage. Calculated impacts were assessed for statistical significance.
- For each TOU participant, the cost of energy usage billed under the TOU rate were compared to what the cost of energy use would have been if it had been billed under the standard residential declining block rates.
- Willing TOU participants were surveyed by a third party to solicit feedback on their experience using the HAN to determine their primary application of the tool and information provided.

3.4.7.4.2 Plan Execution and Analysis

The following sections provide details regarding the functional tests performed, data collection and analysis performed for the Time-of-Use operational test.

3.4.7.4.2.1 Functionality Deployed

KCP&L designed and implemented an aggressive residential pilot TOU rate and offered it to all qualifying residential customers within the project area. Following regulatory approval in December 2011, KCP&L's TOU Pilot tariff went into effect on January 1, 2012. The systems interfaces and configurations were deployed during May/June 2012 and the first customers were enrolled effective with their bills at the beginning of June 2012.

A revenue neutral TOU rate with 6x price ratio and four hour On-Peak period from 3:00-7:00 pm resulted in On-Peak price of $0.3784/kWh and Off-Peak price of $0.0631/kWh, which represents a significant discount relative to the typical standard rate price of approximately $0.12/kWh. Additionally, an Off-Peak period of twenty hours offers significant flexibility and energy shifting potential to maximize this discounted Off-Peak price. A summary of these rate details is shown in Table 3-94.

Table 3-94: Pilot TOU Rate Details

On-Peak Period:	3:00 – 7:00 pm
On-Peak/Off-Peak Price Ratio:	6x
Summer On-Peak Price:	$0.3784/kWh
Summer Off-Peak Price:	$0.0631/kWh
Winter Rates:	Declining Block
Summer Dates:	May 16 – Sept 15
Customer Charge:	$9.00/mo.

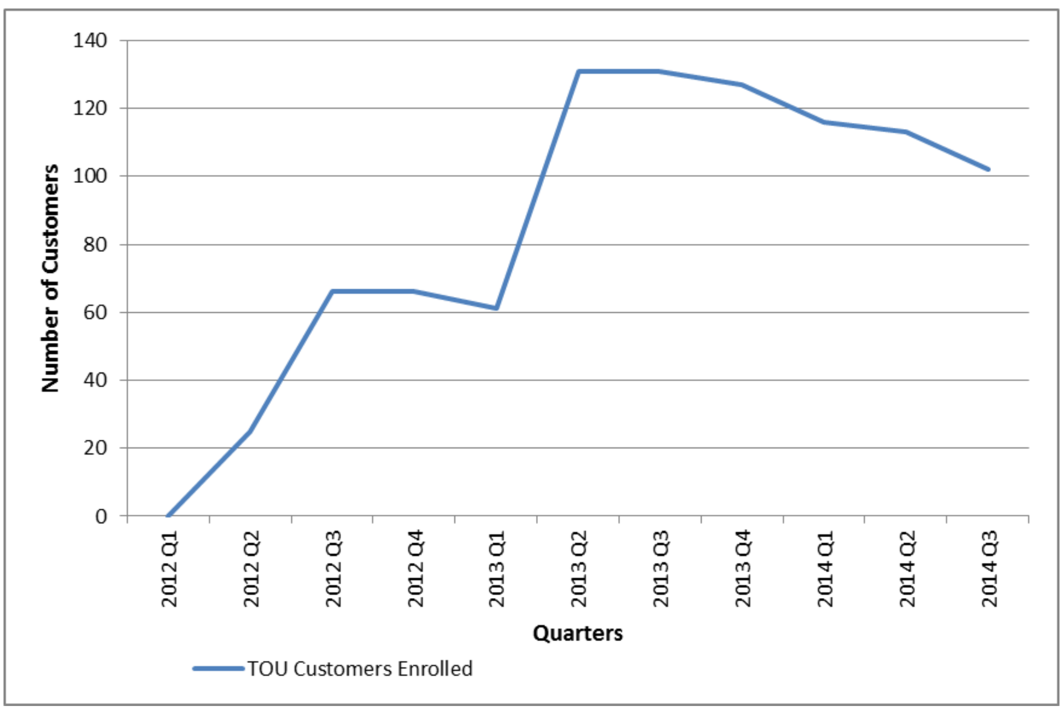
Along with the rate structure and pricing described above, the following business rules were determined by KCP&L and the project team:

- Voluntary TOU rates only affected summer pricing. During winter, customers reverted back to standard winter rates equivalent to standard flat rate
- TOU rate was available to both standard and all-electric customers
- Customers with dual meters were not eligible
- The TOU rate expired at the end of the SGDP, December 31, 2014
- Customers could sign up anytime throughout the year; however, the rates were not affected until the first day of their next billing cycle
- Customers could exit the program at any time; however, they could not re-join at a later time
- Upon request, KCP&L credited customers for losses incurred by the pilot TOU rate relative to standard rate treatment for the current and previous billing cycles only

3.4.7.4.2.2 Program Participation

Residential customers in the SGDP area were eligible to enroll in the TOU rate. Throughout the duration of the program, TOU was available to approximately 12,000 customers. Customers voluntarily enrolled in the TOU program and were allowed to opt-out of the program at any time. At the peak of the program, there were 131 customers on the TOU rate. Figure 3-130 below shows the enrollment in TOU from the inception to the completion of the program.

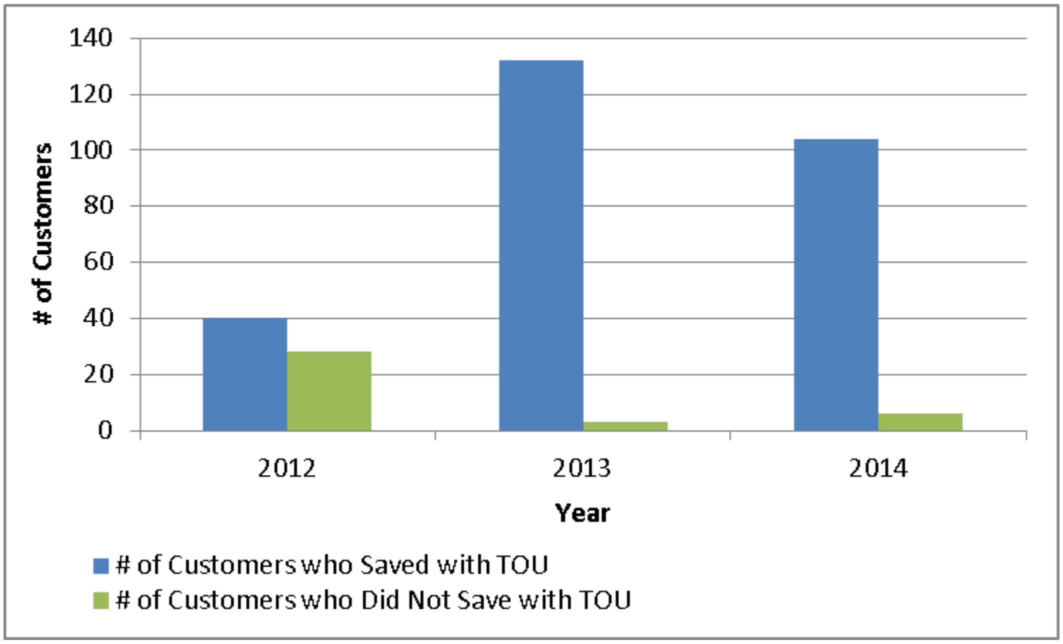
Figure 3-130: TOU Participants Over Time



3.4.7.4.2.3 Participant Bill Impact Analysis

KCP&L conducted an analysis of customer bills to see if customers' bills increased or decreased due to TOU pricing, compared to typical summer pricing. In general customers saved money on the TOU program. Figure 3-131 shows the number of customers who saved money, and the number of customers who did not save, for each of the three summers of the program.

Figure 3-131: Customer Bill Savings with TOU



Throughout the TOU program, many customers saved money on their electricity bills by shifting usage from On-Peak times to Off-Peak times. Customer savings varied widely, but the average savings for the entire summer was approx. $68 in 2013 and 2014. Customers who were most aggressive in shifting their usage to Off-Peak hours saved the greatest amount. Customers who did not alter their usage were less likely to save money. Those that did not save money typically chose to leave the program. Additionally customers left the program when they moved out of the SGDP area. Table 3-95 shows the participation and savings numbers for each year of the program.

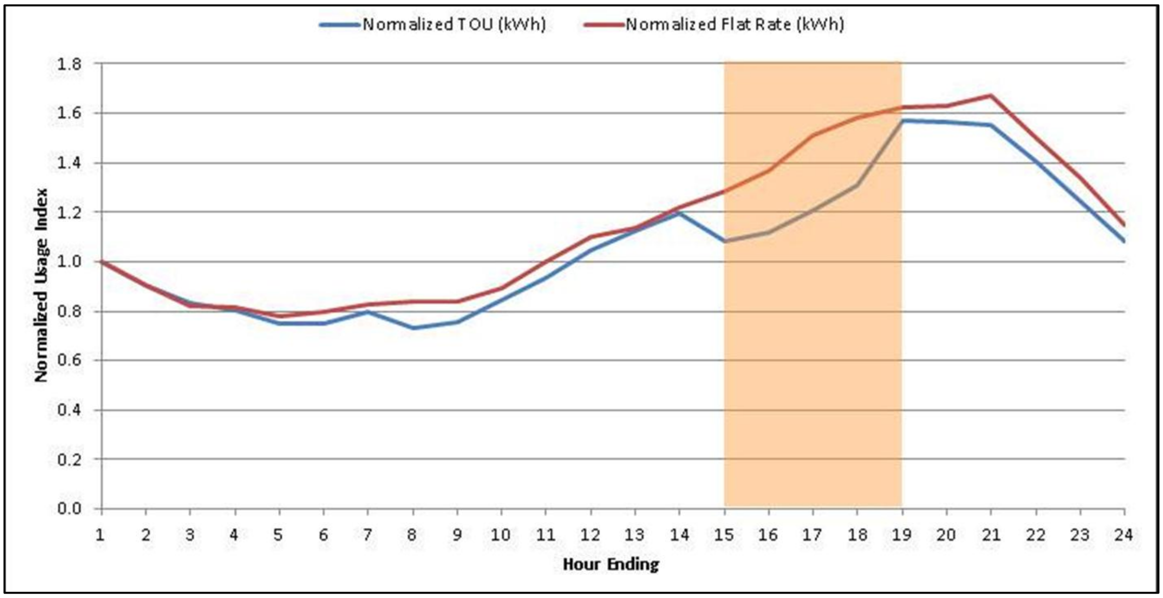
Table 3-95: Customer Savings Analysis by Year

Name	2012	2013	2014
# of TOU Participants	68	145	110
# of Customers who Saved with TOU	40	132	104
# of Customers who Did Not Save with TOU	28	3	6
Average Customer Bill Impact	$22.91	$68.64	$68.24
Average of Customers with Bill Savings	$33.56	$78.21	$73.16
Average of Customers with Bill Increase	$8.64	$28.61	$17.05
Largest Customer Bill Savings	$177.04	$611.34	$329.31
Largest Customer Bill Increase	$107.98	$173.48	$56.35

3.4.7.4.2.4 Participant Usage Impact Analysis

After the first summer of the TOU pricing demonstration EPRI performed a preliminary TOU participant usage analysis. For this preliminary analysis EPRI compared the TOU customer's usage pattern 30 days before and after the implementation of the TOU rate. Figure 3-132 illustrates the change in participant usage patterns upon initial enrollment in the TOU rate.

Figure 3-132: Initial TOU Usage Impact Analysis



For the final participant usage impact analysis EPRI compared the TOU participants' usage to a control group. [30] For this analysis, 99 TOU participants passed the data quality screening and were matched with control group customers using propensity score matching. The TOU customers were divided into three cohorts for analysis, as follows:

- Cohort A – 24 customers who joined the TOU rate in June 2012. May 2012 load data were available for use in matching these customers to control group pool customers.
- Cohort B – 14 customers who joined the TOU rate in July 2012. Propensity score matching was based on load data from May and June 2012 for both TOU and control group pool customers.
- Cohort C – 61 customers who joined the TOU rate in August 2012 or later. Propensity score matching was based on load data from May through July 2012 for both TOU and control group pool customers.

The propensity score matching was accomplished by first estimating a regression model to predict participation in the pilot program (the dependent variable is equal to one for TOU customers and zero for control group pool customers) as a function of a variety of usage-based variables that reflect usage patterns on high, medium, and low temperature days. Each TOU customer was matched to the control group customer that had the closest predicted participation probability (called the propensity score). This created a control group of customers that was used as a reference for measuring impacts of TOU rate participation. Figure 3-133 illustrates the correlation of the load profiles of the Control and Cohort C TOU participants.

Figure 3-133: Cohort C Post Matching Load Profiles

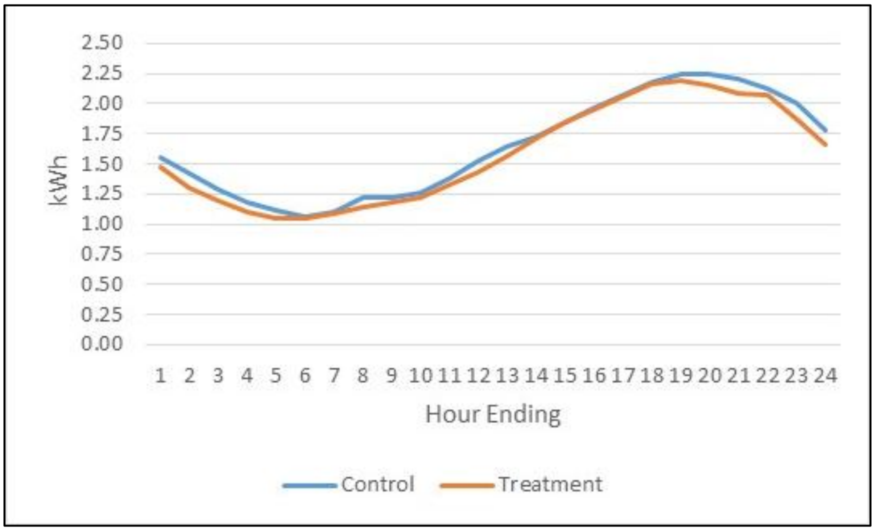


Figure 3-134 and Figure 3-135 show the average load profiles for Cohort C's treatment and matched control customers during the 2013 and 2014 TOU periods. In each case the TOU treatment and matched control load profiles exhibit similar usage patterns.

Figure 3-134: 2013 TOU Usage Impact Analysis

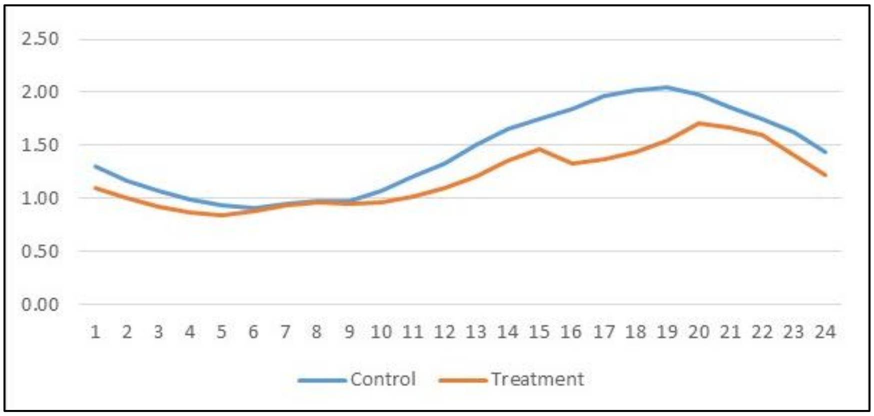
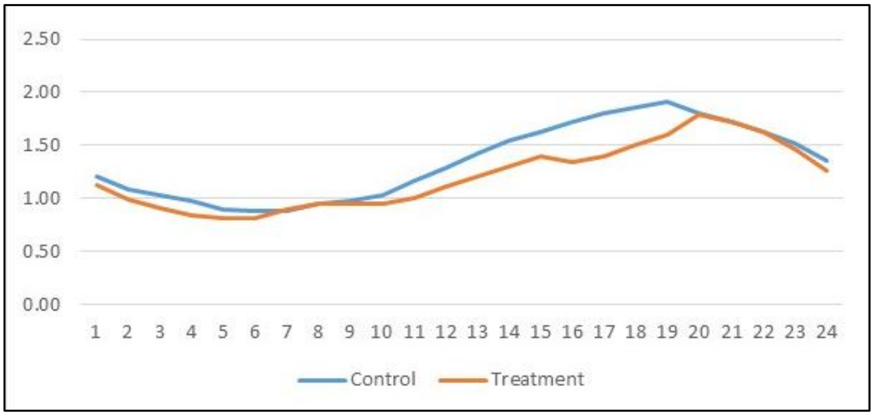


Figure 3-135: 2014 TOU Usage Impact Analysis



EPRI then performed a difference-in-differences analysis using separate models established for each cohort and using three dependent variables: On-Peak to Off-Peak usage ratio; average On-Peak period usage; and average Off-Peak period usage. For each model, separate TOU impact coefficients were estimated for each year. Table 3-96 shows the estimated TOU impact estimates for each cohort and dependent variable. The rightmost column converts the estimated change in the On-Peak to Off-Peak usage ratio into an elasticity of substitution (EOS) factor. The EOS is a measure of the effect of TOU pricing on TOU customers' On-Peak to Off-Peak usage ratio. The implied EOS for the years 2013 and 2014 ranges from 0.088 to 0.240. This analysis indicates that TOU program participants in Cohort C reduced their On-Peak electricity usage by approximately 18% in 2013 and 2014. By comparison, other similarly constructed TOU pilots (i.e., in which no enabling control technology was provided) reported EOS estimates of 0.02 to 0.10.

Table 3-96: Estimates of TOU Demand Response by Cohort

Cohort	Year	On-Peak to Off-Peak Ratio	On-Peak (kWh per hour)	Off-Peak (kWh per hour)	Implied Elasticity of Substitution
A: Joined TOU in June 2012	2013	-0.287++	0.119	0.529++	0.189
	2014	-0.240++	0.410++	0.652++	0.088
B: Joined TOU in July 2012	2013	-0.372++	-0.087	0.218+	0.240
	2014	-0.352++	0.048	0.211+	0.230
C: Joined TOU in August 2012 or later	2013	-0.350++	-0.503++	-0.118++	0.181
	2014	-0.324++	-0.291++	-0.007	0.183

++ p-value < 0.01, + p-value < 0.05

The EPRI analysis estimated customer demand response to TOU rates using a variety of methods. A simple examination of TOU customer load profiles indicates that On-Peak period load reduction is in the range of 0.35 to 0.48 kWh per hour (15 to 20 percent) represent the high end of what one might expect to estimate using more formal methods. The examination does not indicate any substantial load shifting occurred, in fact Cohort C participants demonstrated reduced Off-Peak usage levels relative to the control group. This could be due to other factors that could affect TOU customer loads across years, such as the adoption of efficient lighting or other conservation measures.

The TOU participant response during the summer months appears to be significant, exceeding what most DOE and other industry studies have reported. This level of response may be the result of the TOU program's 6X rate differential, the short 4 hour On-Peak period, and the program participants' desire to save money on their electricity bills.

The results indicate a clear change in customer On-Peak usage in response to TOU pricing. The results are less clear with respect to changes in overall usage levels (i.e., whether Off-Peak period usage increases, decreases, or remains the same following TOU rate adoption). Still, the study provides evidence that customers exhibited significant response to TOU prices.

A summary of the EPRI analysis is included in Appendix Q.

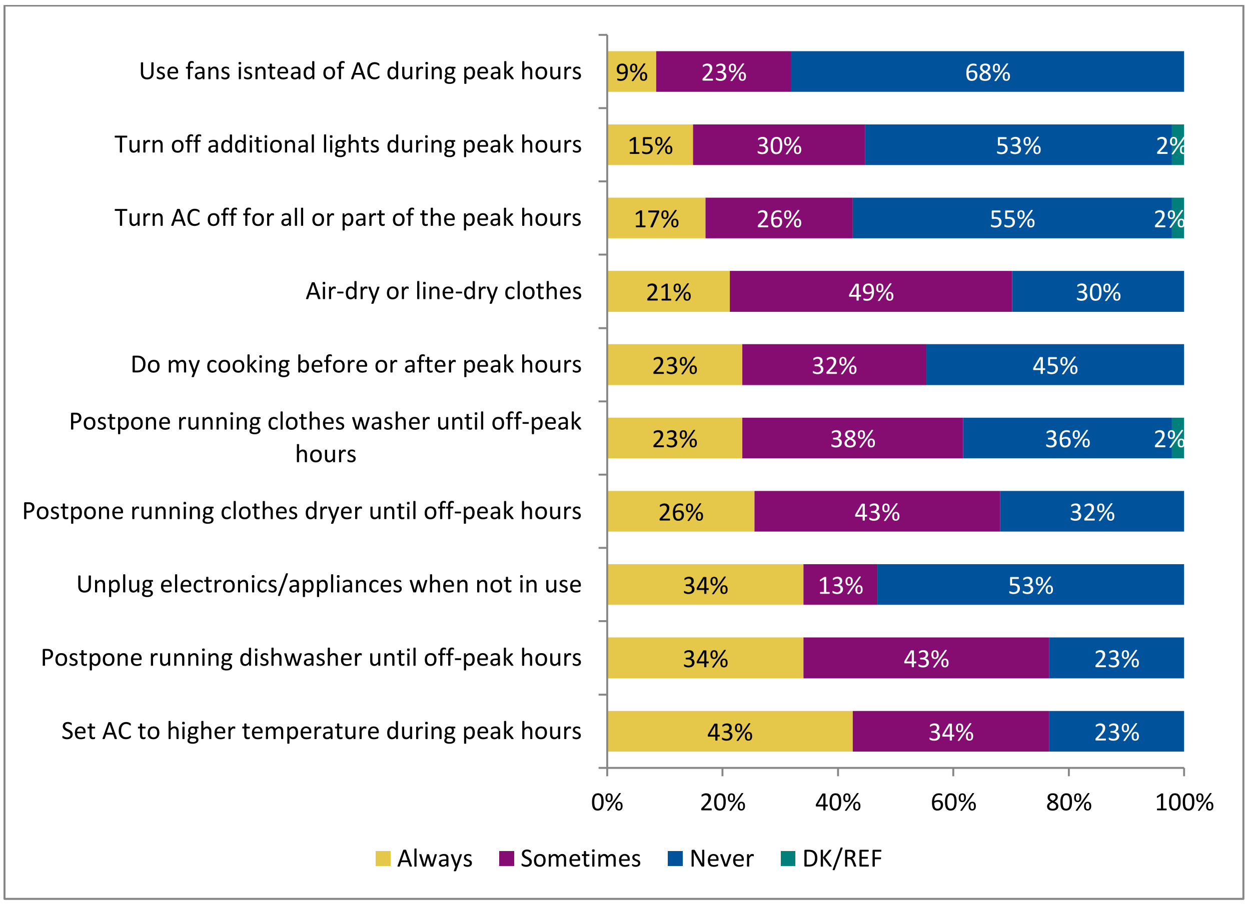
3.4.7.4.2.5 Customer Experience

In 2014 the TOU participants were contacted to participate in a phone survey. 47 respondents completed the survey. TOU participants had a strong awareness about the overall SGDP. 75% of respondents were aware of the project as a whole. The majority of respondents had learned about the opportunity to participate in the TOU program through material they received in the mail. The main reason respondents gave for signing up for the TOU program was to save money, followed secondarily by a desire to help the environment.

Overall, respondents expressed satisfaction with the TOU program and felt that it was easy to understand. 68% of respondents strongly agree that their energy bill decreased after participating in the program, and 62% would recommend the program to family and friends.

When asked if their household regularly altered electricity usage in response to higher peak rates, 49% strongly agreed. Figure 3-136 shows the various ways that respondents altered their usage.

Figure 3-136: Energy Savings Activities During Peak TOU Time

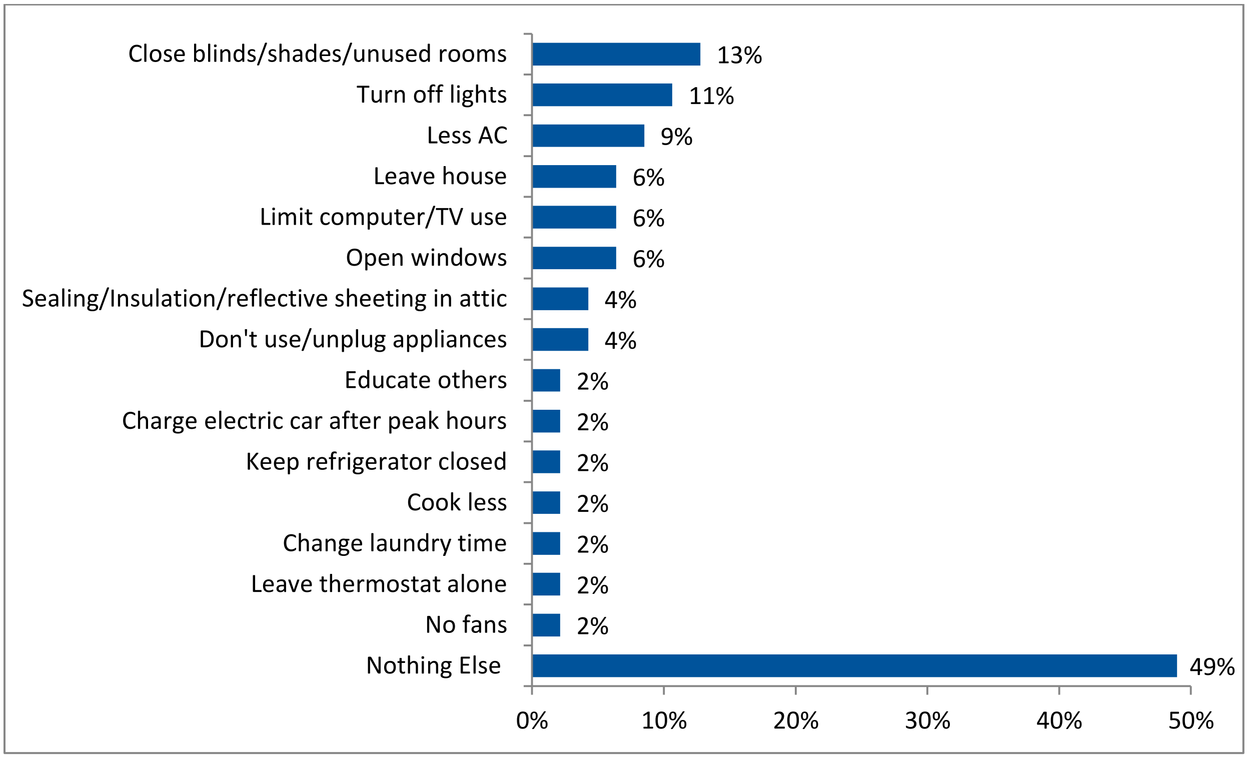


Note: n = 47

Source: Navigant analysis of survey response data

Additionally, half of the respondents listed other actions that they took to save energy during peak hours. These actions are shown in Figure 3-137.

Figure 3-137: Other Energy Savings Activities



Note: n = 47
Source: Navigant analysis of survey response data

For a full version of the Navigant customer survey results, see Appendix R.

3.4.7.4.2.6 Issues and Corrective Actions

The following issues and corrective action were encountered during the performance of the Time-of-Use operational testing and analysis.

Table 3-97: Issues and Corrective Actions

Issue	Corrective Action
• IHDs needed to display the peak pricing during TOU peak hours.	• A special, daily “event” pricing had to be set up to create a pricing event from 3-7 PM on the IHDs to display the correct price during TOU peak hours.
• Missing usage data for TOU accounts often due to customer move in/outs.	• Implemented a screening process to filter out accounts that did not have adequate interval data for analysis purposes.

3.4.7.4.3 Findings

The results obtained in the execution and analyses of Time-of-Use operational analysis are summarized in the sections below.

3.4.7.4.3.1 Discussion

KCP&L's SGDP has provided significant insight about deploying a Time-of-Use program.

Throughout the TOU program, many customers saved money on their electricity bills by shifting usage from On-Peak times to Off-Peak times. Customer savings varied widely, but the average savings for the entire summer was approx. $68 in 2013 and 2014. Customers who were most aggressive in shifting their usage to Off-Peak hours saved the greatest amount. Customers who did not alter their usage were less likely to save money. Those that did not save money typically chose to leave the program.

EPRI then performed a usage impact analysis that showed the TOU participants reduced their On-Peak electricity usage by 15-20 % in 2013 and 2014. The TOU participant response during the summer months appears to be significant, exceeding what most DOE and other industry studies have reported. This level of response may be the result of the TOU program's 6X rate differential, the short 4 hour On-Peak period, and overriding desire of the Green Impact Zone program participants to save money on their electricity bills. While these results are encouraging, the project team cannot conclude that an enterprisewide offering of a similar TOU program would result in the same level of participant response.

Based on the Navigant customer survey, customers signed up for TOU to save money and help the environment. TOU participants had a strong awareness about the overall SGDP. Overall, respondents expressed satisfaction with the TOU program and felt that it was easy to understand. 68% of respondents strongly agree that their energy bill decreased after participating in the program. When asked if their household regularly altered electricity usage in response to higher peak rates, 49% strongly agreed.

3.4.7.4.3.2 Expectations vs. Actuals

The following table provides a comparison of the Expected Results and the Actual Outcomes for the Time of Use operational demonstration.

Table 3-98: Expected Results vs. Actual Outcomes

Expected Results	Actual Outcome
• TOU participants will shift load from On-Peak to Off-Peak times	• EPRI's analysis showed that TOU users on average reduced their On-Peak usage by 15-20%. The analysis could not confirm a shift in usage from On-Peak to Off-Peak times.
• TOU participants will reduce their overall kWh consumption	• EPRI's analysis of TOU users could not confirm a significant change in overall energy consumption.
• TOU participants will achieve an overall reduction in their electricity bill	• The majority of TOU participants achieved a reduction in their electricity bill. The average savings for 2013 and 2014 was approx. $68.
• TOU participants that also participate in HAN programs may achieve greater savings than participants without devices.	• Due the limited number of TOU customers that also participated in the HAN program, KCP&L was unable to perform this analysis.

3.4.7.4.3.3 Computational Tool Factors

The following table lists the values derived from the Time-of Use operational test analysis that will be used as inputs to the SmartGrid Computational Tool.

Table 3-99: Computational Tool Values

Name	Description	Calculated Value
Reduced Customer Load at Annual Peak Time (MW)	The total customer peak demand for customers. This input includes any impacts from energy efficiency, demand response and any other programs or technology that result in customer electricity use optimization	0.024 MW
Reduced Total Residential Electricity Cost ($)	Changes in usage can result in reductions in the total cost of electricity.	$ 7,506

- Reduced Total Customer Peak Demand (MW) – Based on the 2014 participant usage impact analysis, the participants reduced their peak usage by 15-20% which is considerably higher than other studies. For the SGCT analysis the team chose to use 10 % which is on the high end of other analysis and may be more indicative of a larger program offering. This value is calculated as follows:

Total TOU Customers (#) x [Peak Load-Residential (MW) ÷ Total Residential Customers (#)] x TOU Load Shift (%) =

110 x [26.987 MW ÷ 12,204] x 10 % = 0.024 MW

- Reduced Total Residential Electricity Cost (Consumer) Cost ($) – Based on the 2014 TOU participant bill impact analysis, this value is calculated as follows:

Total TOU Customers (#) x Average Customer Bill Impact ($) =

110 x $68.24 = $7,506

3.4.7.4.4 Lessons Learned

Throughout the conduct of the operational testing and analysis of the Time-of-Use rate, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- Overall, enrollment in the TOU program was higher than anticipated. TOU enrollment peaked in 2013 with 131 customers, or roughly 1% of the SmartGrid Demonstration customers enrolled.
- Program design and communication are crucial to customer acceptance. The project team found that customers were receptive to an aggressive TOU pricing program (6x rate differential) if the program was simple to understand and the customers risk exposure (On-Peak hours) was limited.
- The project team further reduced customer risk by allowing customers to exit the program at any time and upon request, KCP&L would credit customers for increased costs incurred by the pilot TOU rate for the current and previous billing cycles only. While very few customers exited the program, customers viewed this as a positive aspect of the program.
- Overall, customers were satisfied with the program, and nearly all participants reduced their On-Peak electricity usage by 15-20% and saved money on their electricity bills.

3.4.8 Distributed Production of Energy

Smart grid functions allow utilities to remotely operate DG systems to control output, defer upgrades to generation and T&D assets, and improve voltage regulation. This category includes dispatchable, distributed generation such as combined heat and power, fossil fuel powered backup generators, bio-fuel powered backup generators (e.g., biodiesel, waste to energy, digester gas) or geo-thermal energy. It also includes variable, distributed generation such as solar and wind.

3.4.8.1 Distributed Rooftop Solar Generation

Distributed Rooftop Solar Generation is a demonstration of one aspect of the Distributed Production of Energy function.

3.4.8.1.1 Overview

The following sections provide an overview of the operational, demonstration, testing, and evaluation methodology used for the Distributed Rooftop Solar Generation operational demonstration.

3.4.8.1.1.1 Description

Approximately 180 kW of distributed solar capacity was installed within the SGDP area. One large commercial-scale system was installed on a local school rooftop, and other, smaller distributed systems were installed at businesses throughout the project area. All solar systems are utility-owned, installed on leased rooftops, and connected on the utility side of the meter.

3.4.8.1.1.2 Expected Results

This technical demonstration was expected to yield the following:

- Determination of the percent of nameplate that solar generation systems in Kansas City could be expected to produce, and verification of the annual kWh solar production estimates produced by the NREL PVWatts Calculator.
- Determination of the coincidence of solar generation with system annual peak, expressed as a percentage solar generation nameplate rating.
- Development of a composite per unit “solar generation” load profile that could be used to study the impact of solar generation on customer-, circuit-, and system-level analysis.
- Determination of the go-forward viability of a “leased rooftop’ business model for utility-owned distributed solar generation.

3.4.8.1.1.3 Benefit Analysis Method/Factors

The DOE SGCT was used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits were quantified.

- Optimized Generator Operation
- Deferred Generation Capacity Investments
- Reduced CO_2 Emissions

Benefits were calculated using SGCT formulas. The following factors were measured, projected, or calculated during the application operation and/or demonstration.

Optimized Generator Operation

- Reduced Annual Generation Cost ($)

Deferred Generation Capacity Investments

- Distributed Generation Use at Annual Peak Time (MW)

Reduced CO_2, SOx, NOx and $PM_{2.5}$ Emissions

- Annual Distributed Generation Production (MWh)

3.4.8.1.1.4 Testing Methodology

The following points provide an overview of how the operational demonstration and testing for this application was accomplished:

- Utility solar photovoltaic generation systems were installed on customers' leased rooftops, and utility property.
- Energy delivered to and received from the solar generation system was measured by the AMI net meters installed at the grid interconnection. All AMI data collected were stored in KCP&L's MDM and DMAT systems.
- AMI 15-minute interval load data were collected for each solar generation site over several months and used for analysis.

3.4.8.1.1.5 Analytical Methodology

The following points provide an overview of the analytical methods that were used to evaluate the impact and benefits of this application:

- AMI interval load data for each solar generation customer within the Project area was be extracted from the MDM System through KCP&L's DMAT.
- The DMAT has built-in functionality that enabled the aggregation and calculation of the following hourly load profiles.
  - Net Energy Solar Production from each Solar Generation site.
  - Total Net Energy Solar Production for all Solar Generation sites.
  - Average Net Energy Solar Production per kW of Solar Generation Nameplate Capacity
- Distributed Generation Use at Annual Peak Time (MW) was determined by selecting the Total Net Energy Solar Production value at the System Annual Peak Hour.
- Annual Reduced Utility Electricity Cost analysis was performed by combining the hourly savings that are calculated from the hourly Total Net Energy Solar Production load profile data and the hourly average and marginal energy production cost data.

3.4.8.1.2 Plan Execution and Analysis

The following sections provide details regarding the functional tests performed, data collected, and analysis performed for the Distributed Rooftop Solar Generation operational test.

3.4.8.1.2.1 Solar Generation Installations

KCP&L completed the installation of nine separate PV systems with a total nameplate capacity of 176.6 kW. Each of the PV systems is connected directly to the grid through an AMI meter. The kWh generated and consumed by the PV system was captured in 15-minute interval data and stored in KCP&L's DMAT for analysis purposes. Table 3-100 provides a summary of each PV system along with some of each one's characteristics.

The PV installations ranged in size from a small, 2.82-kW residential installation at the demonstration house to a large, 100-kW installation at Paseo High School. At the time of construction, the installation at Paseo High School was the largest PV installation in the Kansas City metropolitan area. While most installations were rooftop, a ground mount array was installed at KCP&L's SmartGrid innovation Park, and several of the installations incorporated Sunverge local premise storage units. Photos of many of these installations are incorporated throughout this document. Figure 3-138 shows a solar installation at the Crosstown Substation, incorporated into an award-wining substation wall project in the Kansas City Crosstown Arts District. The solar panels were sized to supply necessary energy for the artistic nighttime light display on the north wall of the substation.

Figure 3-138: Crosstown Substation Solar Installation

Quantifying the percent of nameplate that a solar installation could achieve in the Kansas City area was one of the questions KCP&L wanted to answer with this operational demonstration and analysis. Table 3-100 shows the maximum electric generation output hour that has been achieved for each of the installations. These values range from 72.9% to 93% of nameplate with the average being 84%. The variations are due to the differences in solar panel and inverter technologies utilized, along with the orientation and angle at which the panels are installed. The installation at Crosstown Substation was excluded from the average calculation due to its unique installation characteristics and location, which leave it considerably shaded by adjacent buildings.

Table 3-100: SmartGrid PV Systems Installed

System Location	Inverter	Solar Rating (kW)	In-Service Date	Peak Hour (kWh)	Peak Time	Percent Name Plate
Project Living Proof (Demonstration Home)	String	3.15	1/19/2011	2.59	9/10/2012 1:00:00 PM	82.15%
Project Living Proof (Replacement)	Sunverge	2.82	06/28/2014	2.43	8/12/2014 2:00:00 PM	86.33%
Paseo High School Gymnasium Rooftop	String	99.18	4/19/2012	84.66	5/11/2013 1:00:00 PM	85.36%
Innovation Park (Midtown Substation)	String	5.00	10/17/2012	4.65	3/20/2013 1:00:00 PM	93.02%
Crosstown Substation *	Combo	29.33	6/7/2013	3.73	8/30/2014 2:00:00 PM	12.71%
MRIGlobal	Sunverge	10.56	5/16/2013	8.13	2/26/2013 11:00:00 AM	76.96%
UMKC Flarsheim Hall	Sunverge	4.32	8/18/2013	3.73	3/23/2014 1:00:00 PM	86.28%
UMKC Student Union	String	5.28	8/18/2013	4.63	3/25/2014 1:00:00 PM	87.72%
Blue Hills	Micro	10.08	8/18/2013	8.70	3/25/2014 1:00:00 PM	86.34%
KCMO Swope Park Office	Micro	10.00	12/31/2013	7.29	6/13/2014 12:00:00 PM	72.94%
Average						**84.12%**

3.4.8.1.2.2 Solar Energy Delivered to the Grid

Another objective of the Distributed Rooftop Solar Generation demonstration and analysis was to understand the solar generation characteristics in Kansas City and to verify the solar energy production annual system load factors provided by the NREL PVWatts Calculator.

The PVWatts Calculator V1 & V2 both estimate that a rooftop solar installation in Kansas City would produce 1,312 W-AC per kW-DC annually, for an annual solar production load factor of 14.98%. The new PVWatts Calculator released in the fall of 2014 by NREL now estimates that a similar installation would produce 1,389 W-AC per kW-DC annually, for an annual solar production load factor of 15.85%.

For this analysis, the installations that incorporated the Sunverge premise energy storage units and the Crosstown Substation installation were excluded. Table 3-101 provides the summary of kWh generated by the remaining solar systems by season, along with the resulting annual solar production load factor. Overall, the results from the demonstration solar systems, with an annual load factor of 15.74%, correlate very closely to those estimated by the new PVWatts Calculator.

It should be noted that each of the demonstration solar systems were offline for several days for various reasons, as listed in the table notes. The loss of system availability prompted modification the load factor calculation based on the available days, causing some of the small discrepancy between the PVWatts Calculator estimates and resulting calculations. It is believed that the Paseo High School installation fell below this norm due to the nature of its rooftop construction, as the solar panel mounting used on the large, flat roof has a pitch significantly less than the other installations. This lower pitch reduces solar efficiency and allows snow to more easily accumulate on panels in the winter.

Table 3-101: SmartGrid PV Energy Delivered to Grid

System Location	Solar Rating (kW)	Fall 2013 kWh	Winter 2014 kWh	Spring 2014 kWh	Summer 2014 kWh	Annual kWh	Days Avail.	Annual Load Factor
Project Living Proof*	3.15	1,031	339*[2]	131*[2]	954*[2]	2,455	244	13.31%
Paseo High School *[3]	99.18	26,773	14,366	24,873	43,184	109,196	337	13.61%
Innovation Park*[4]	5.00	1,760	1,156	1,941	1,245	6,102	323	15.74%
UMKC Student Union*[5]	5.28	0	1,042	2,160	2,366	5,568	268	16.40%
Blue Hills*[6]	10.08	798	1,955	4,095	4,515	11,363	305	15.40%
Total/Average*[7]	122.69	30,362	18,858	33,200	52,264	134,684	- - -	**15.74%**

Note:

- * *Project Living Proof unit date is for original system operation from September 2012 to August 2013.*
- *[2] *Project Living Proof unit data unreliable from 1/17/2013 thru 5/15/2013 due to demo house activities.*
- *[3] *Paseo HS unit unavailable from 4/14/2013 through 5/11/2014 due to a copper theft.*
- *[4] *Innovation Park unit data unavailable from 6/24/2014 through 7/28/2014 due to a meter failure and 5 misc. days for other reasons.*
- *[5] *UMKC Student Union unit data unavailable from 9/1/2013 through 12/5/2013 due to incomplete installation.*
- *[6] *Blue Hills unit data unavailable from 9/1/2013 through 10/30/2013 due to incomplete installation.*
- *[7] *The Average Annual load factor is the weighted average excluding Project Living Proof and Paseo High School units.*

The total energy produced by quarter follows the expected pattern: highest in summer (June-August), lower in the spring and fall, and lowest in the winter (December-February). Because of incomplete data from individual sites, it was difficult to draw any conclusions by simple inspection of the totals. In subsequent analysis, a composite load profile for all systems will be developed.

While the energy produced by a site varied significantly throughout the year, the maximum kW produced on a good day did not vary significantly throughout the year. Instead, the energy produced was a factor of the length of production and the number of good production days. The following Figures provide illustrations of the load profiles for the best and worst solar production days by season for several of the key installations.

Figure 3-139: Solar Generation Profile – Paseo High School 100 kW

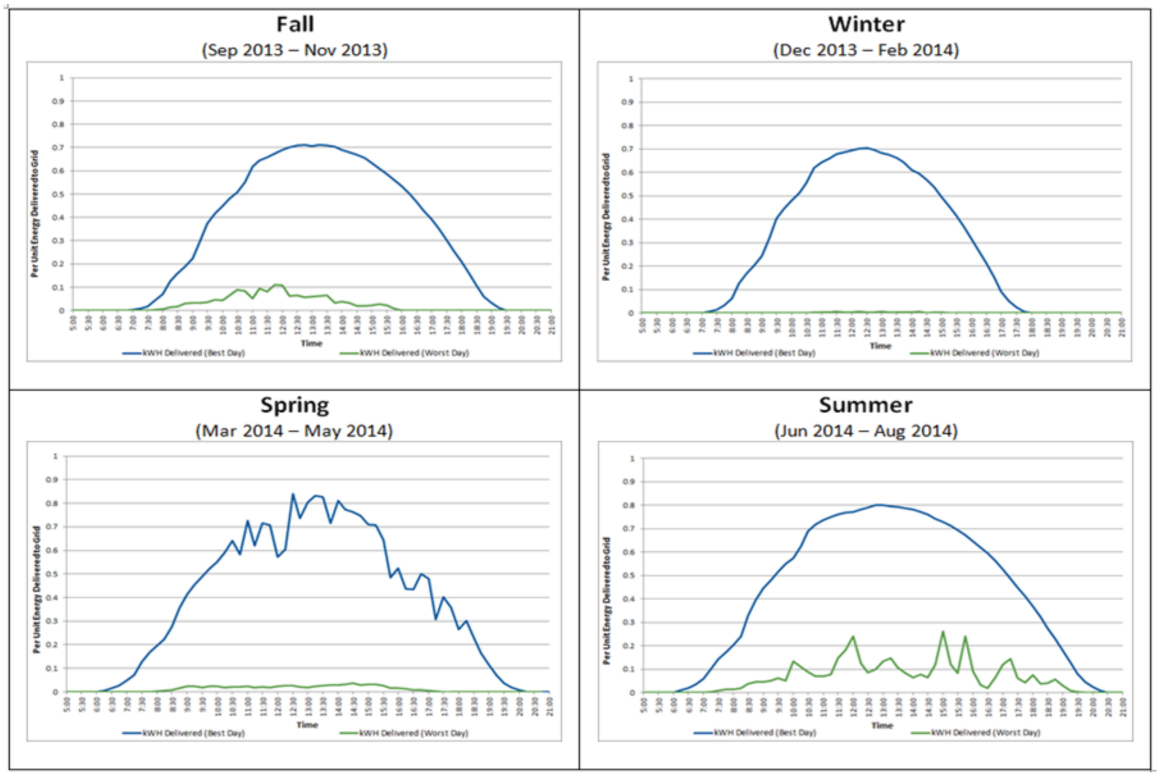


Figure 3-140: Solar Generation Profile – Innovation Park 5 kW

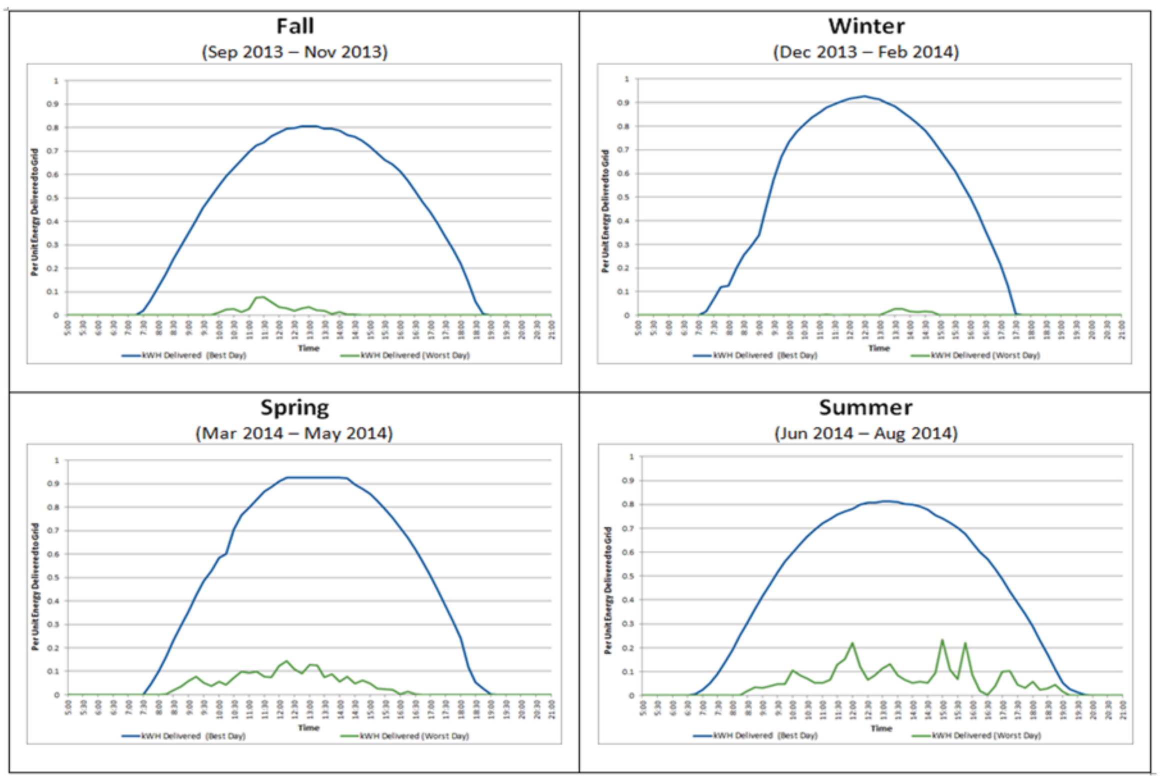


Figure 3-141: Solar Generation Profile – Blue Hills 10.08 kW

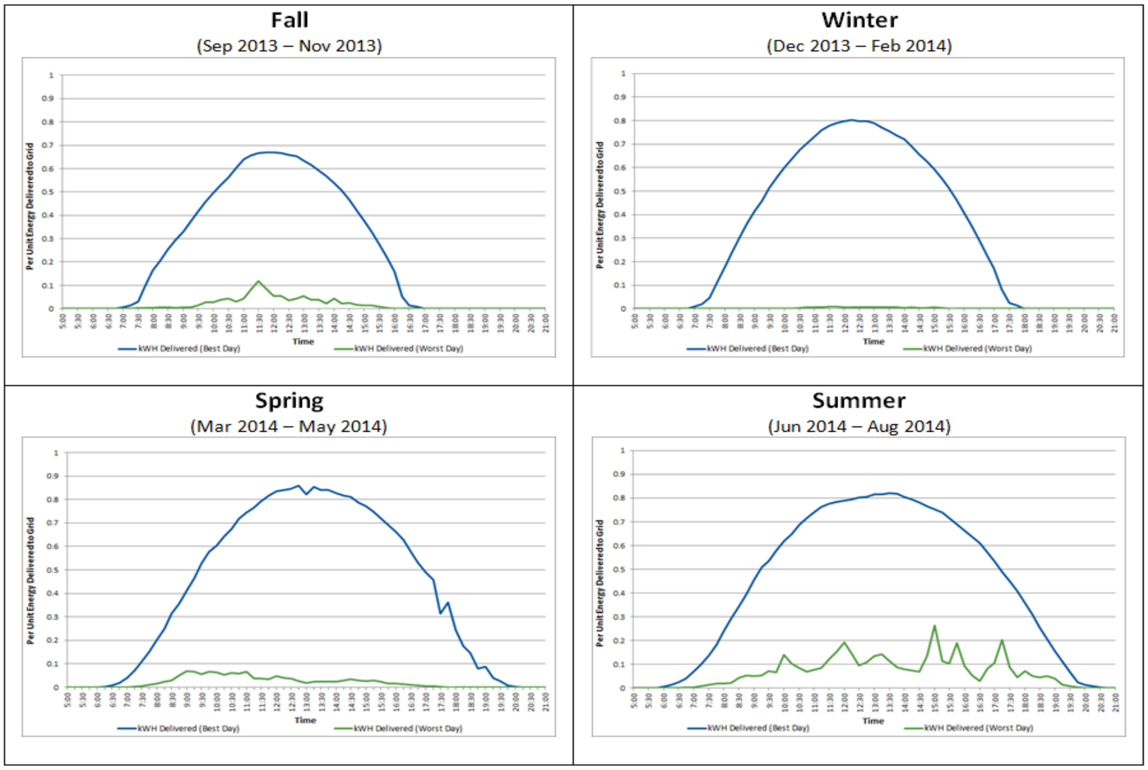
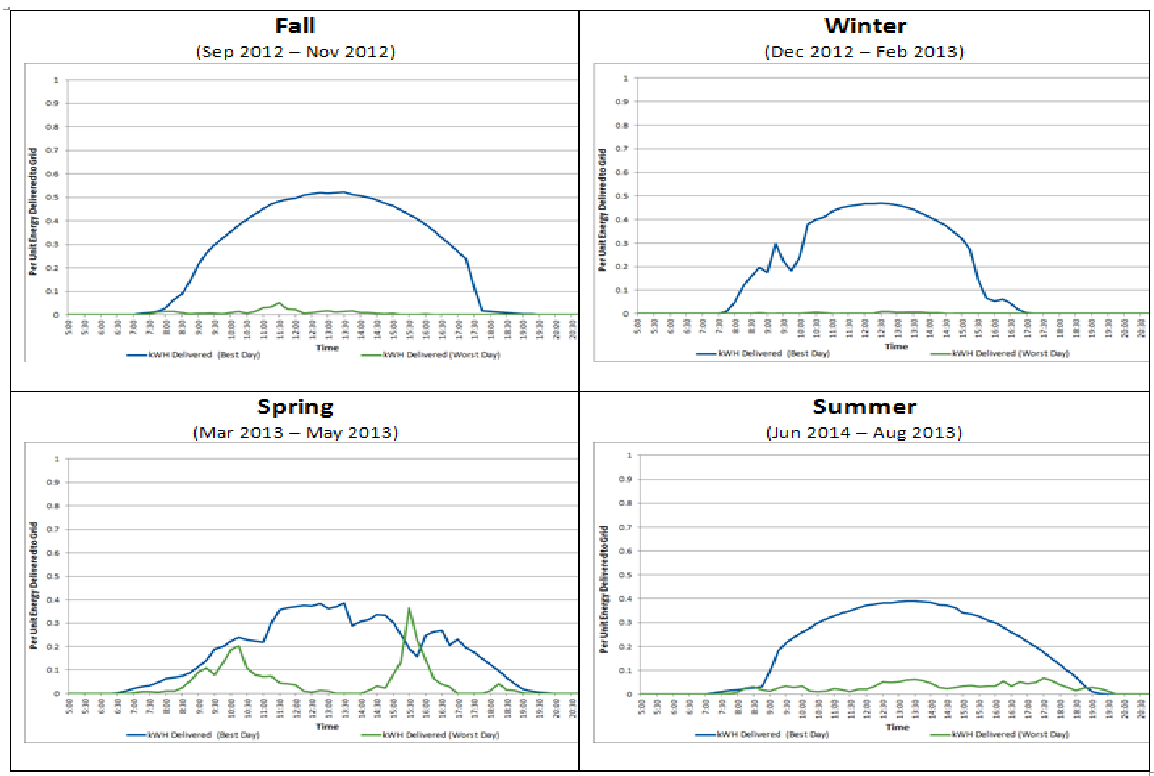


Figure 3-142: Solar Generation Profile – Project Living Proof 3.15 kW



3.4.8.1.2.3 Grid Energy Consumed by Solar Generation

The project team performed an analysis of the data collected on the PV systems to quantify the amount of energy consumed by PV system inverters when they were not generating energy from the solar panel. The kWh consumed by the PV system was captured in 15-minute interval data using the AMI net meter and stored in KCP&L's DMAT for analysis purposes. As noted in previous sections, each of the demonstration solar systems was offline for several days for various reasons. The loss of system availability caused us to modify the annual load factor calculation based on the available days.

Table 3-102 provides a summary of the energy consumed by the PV systems by season, along with the analysis performed. Discovery that the energy consumed by the PV inverter was relatively insignificant provided a pleasant surprise. On average, the PV systems consumed 3.1 kWh annually for each kW of solar generation capacity. Additionally, the micro-inverter installation consumed only 1.2 kWh annually for each kW of solar capacity, less than half of the traditional central inverter installations.

Table 3-102: SmartGrid PV Energy Received From the Grid

System Location	Solar Rating (kW)	Invert. Rating (kW)	Fall 2013 kWh	Winter 2014 kWh	Spring 2014 kWh	Summer 2014 kWh	Annual kWh	Days Avail.	Annual Load Factor*
Paseo High School	99.18	100.00	88	104	52	69	313	337	0.039%
Innovation Park	5.00	4.80	3	4	3	2	12	323	0.032%
UMKC Student Union	5.28	5.00	3	3	3	3	12	268	0.037%
Blue Hills (micro-invert.)	10.08	9.45	1	3	3	3	10	305	0.014%
Total/Weighted Average	119.54	119.25	95	114	61	77	347	- - -	0.036%

Note: The Annual Load Factor calculation is based on the Inverter Rating.

3.4.8.1.2.4 Capacity Coincidence of Solar Generation

Another key objective of the Distributed Rooftop Solar Generation demonstration and analysis was to understand the coincidence of solar generation in the Kansas City area with annual system peaks, which typically occur between 4 PM and 5 PM in July or August. Table 3-103 summarized the solar generation output recorded during the system peak hours for 2013 and 2014. This analysis shows that solar generation in the Kansas City area only contributes 40% to 55% of its solar rating at system peak. A system peak event in early July would lead to an expectation for solar coincidence as high as 55%. But as peak events occur later in the year, the coincidence reduces – to 40% by late August.

Table 3-103: PV Generation Coincident with System Peak

System Location	Solar Rating (kW)	2013 Peak Hr. 7/9, 4-5pm		2013 Peak Hr. 8/30, 4-5pm		2014 Peak Hr. 8/25, 4-5pm	
		kW	%Rating	kW	% Rating	kW	% Rating
Paseo High School	99.18	54.04	54.48%	44.18	44.54%	40.78	41.12%
Innovation Park	5.00	2.62	52.40%	2.34	46.80%	2.43	48.60%
UMKC Student Union*	5.28	N/A		N/A		2.49	47.15%
Blue Hills*	10.08	N/A		N/A		4.71	46.73%
KCMO Swope Park Office*	10.00	N/A		N/A		4.24	42.40%
Total		38.05	**54.39%**	31.974	**44.65%**	41.54	**42.18**

Note: Crosstown and installations with Sunverge storage units were excluded from the analysis.
**Installations were not complete for the 2013 system peaks.*

3.4.8.1.2.5 Composite Solar Generation Load Profile

One of the key objectives of the Distributed Rooftop Solar Generation demonstration and analysis was to understand the solar generation characteristics in Kansas City and to develop a composite per unit solar generation load profile that can be used to incorporate the impact of solar generation on customer, circuit, and system level analysis.

The kWh produced by the PV systems was captured in 15-minute interval data using the AMI net meter and stored in KCP&L's DMAT for analysis purposes. As noted in previous sections, each of the demonstration solar systems was offline for several days for various reasons. For this analysis, data were used from the three sites that had the most complete production data for the final year of the operational period: Innovation Park, UMKC Student Union, and Blue Hills. Solar production interval data for each system were extracted from the DMAT and a composite per unit solar production value was calculated for each interval. The composite solar production value was calculated as the weighted average (based on solar rating) of the actual kWh generated by each individual system.

A summary of the composite solar energy production load curve developed through this analysis is summarized and presented in Table 3-104, Figure 3-143, and Figure 3-144. The composite solar production indicates that a 1.0 kW-DC of solar PV will produce 1396 kWh, 0.5% more than estimated by the PV Watts Calculator, annually, for an annual production load factor of 15.94%.

To aid in subsequent customer benefit cost analysis, the 15-minute composite generation profile was analyzed further to determine the kWh that could be expected to be produced during the typical residential peak usage times (4-8 PM M-F). Annually, the 1.0 kW-DC of solar PC would be expected to produce 145 kW, approximately 10% of its annual production, during these peak residential usage times.

Table 3-104: PV Generation Coincident with System Peak

Year	Month	No. of Days	On-Peak Energy (4 PM-8 PM M-F) (kWh)	Off-Peak Energy (kWh)	Total Energy (kWh)	PVWatts - AC Energy (kWh)	Load Factor
2013	Sept.	30	14.71	121.98	136.68	119	18.98%
2013	Oct.	31	10.48	112.21	122.69	110	16.49%
2013	Nov.	30	0.92	81.80	82.72	77	11.49%
2013	Dec.	31	0.29	55.14	55.44	73	7.45%
2014	Jan.	31	1.50	83.84	85.34	85	11.47%
2014	Feb.	28	3.44	62.22	65.66	88	9.77%
2014	March	31	13.17	117.98	131.15	122	17.63%
2014	April	30	17.43	103.06	120.49	131	16.73%
2014	May	31	19.33	131.59	150.92	148	20.29%
2014	June	30	19.87	118.80	138.67	144	19.26%
2014	July	31	26.88	138.90	165.78	149	22.28%
2014	Aug.	31	17.71	122.90	140.62	142	18.90%
Total		365	**145.75**	**1,250.42**	**1,396.16**	1,388	**15.94%**

Figure 3-143: Monthly Composite Solar Energy Production

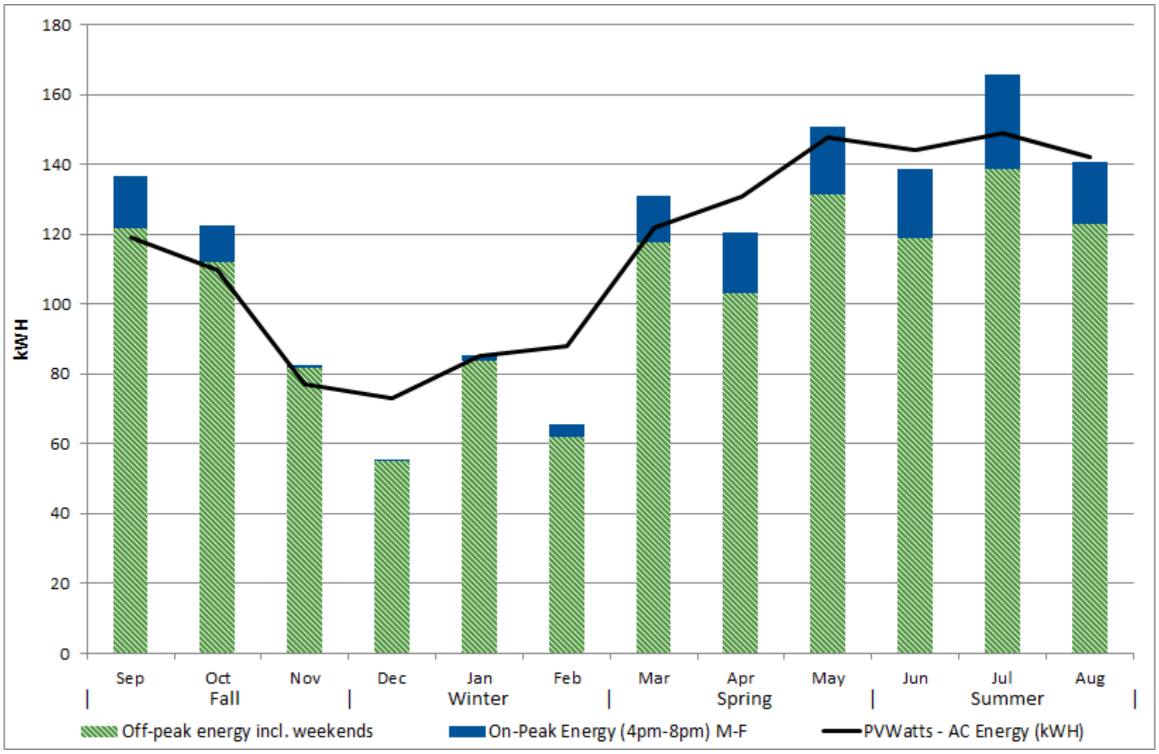
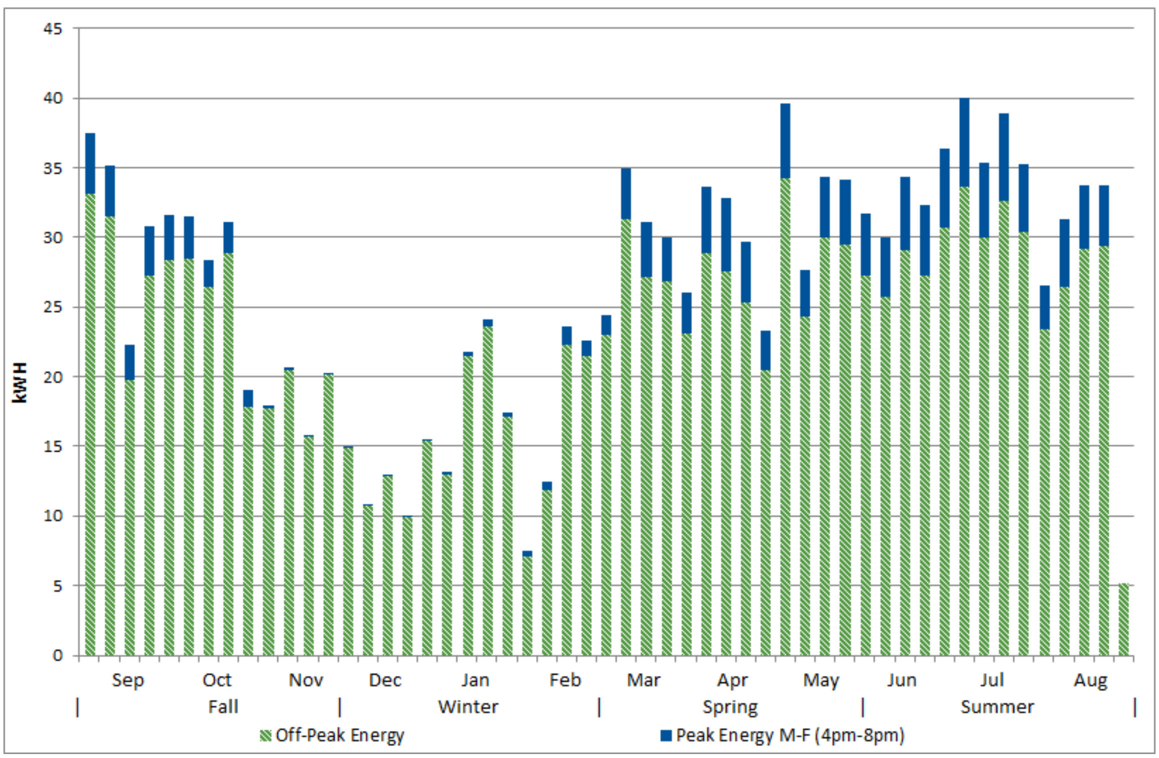
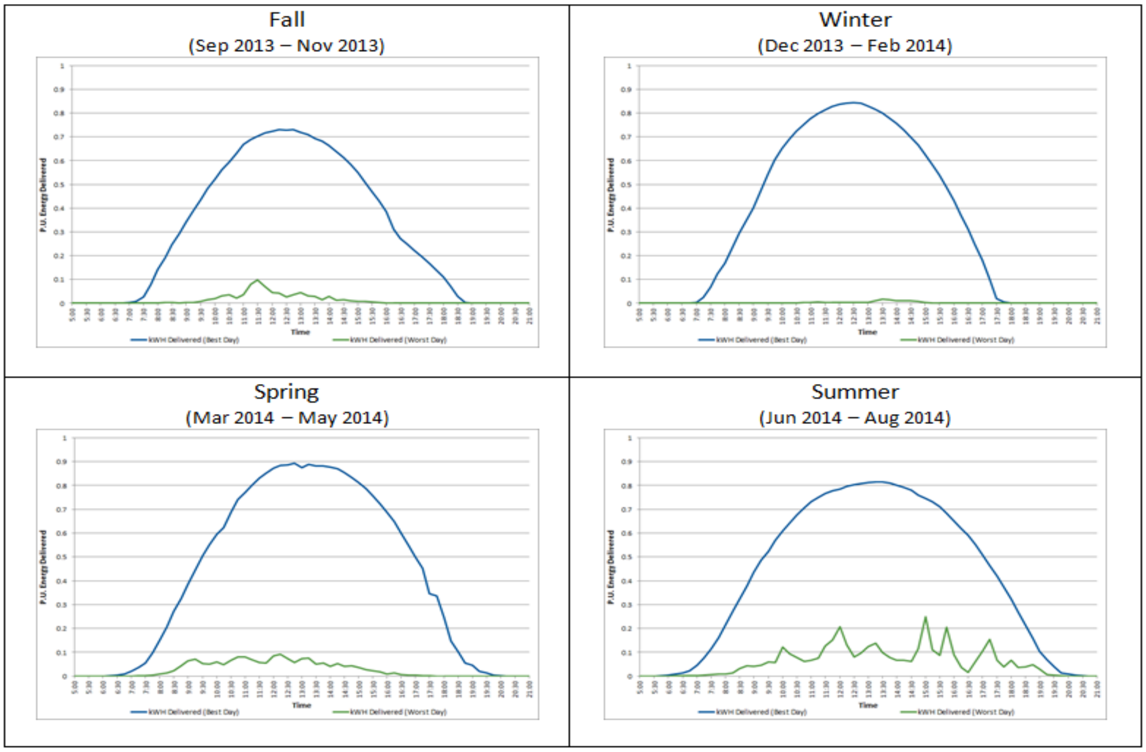


Figure 3-144: Weekly Composite Solar Energy Production



The following figure provides illustrations of the composite PV production load profiles for the best and worst solar production days by season.

Figure 3-145: Composite Solar kW – Typical Day



3.4.8.1.2.6 Issues and Corrective Actions

The following issues and corrective action were encountered during the performance of the Distributed Rooftop Solar Generation operational testing and analysis.

Table 3-105: Issues and Corrective Actions

Issue	Corrective Action
• KCP&L legal determined that a long-term rooftop lease would be a property encumbrance requiring approval of both the property owner and the mortgage insurance holder.	• Site selection was refocused on locations that were owned outright by property owners. Unfortunately, this excluded most potential residential properties.
• The PLP installation was installed as a net metered installation. Due to operational issues with the HAN, it was switched to a grid-connected site for HAN operational testing.	• Project Living Proof installation data were presented where available, but excluded from most of the solar generation analysis.
• The Sunverge energy components installed on several installations distorted the solar generation AMI data available from the DMAT.	• Installations with Sunverge units were excluded from the solar generation analysis.
• Construction delays and operational issues prevented all of the systems from being functional for the entire operational analysis period.	• Analysis focused on the final year, which had the best operational performance. Analysis methods also were based on the available units.

3.4.8.1.3 Findings

Results obtained in the execution and analyses of the Distributed Rooftop Solar Generation operational demonstration are summarized in the sections below.

3.4.8.1.3.1 Discussion

KCP&L installed 170 kW of solar generation systems at nine locations using a variety of solar panel and inverter technologies on installations that included a small residential roof, small and large commercial rooftops, and a ground mount installation.

It was determined that the maximum electric generation output hour that a solar installation could be expected to achieve in the Kansas City was, on average, 84% of its solar nameplate rating. The individual site values ranged from 72.9% to 93% of nameplate, with the variations due to the differences in solar panel and inverter technologies along with the orientation and angle at which the panels were installed.

The New PVWatts Calculator, released in the fall 2014, estimate that a rooftop solar installation in Kansas City would produce 1,389 W-AC per kW-DC annually for an annual solar production load factor of 15.85%. Analysis of the project's three newest installations showed an average, annual solar production load factor of 15.74%, just slightly below the PV Watts Calculator estimates. When factoring in the impact of the data loss experienced on project sites, it is believed that the new NREL Calculator provides very credible estimates of the solar generation for sites in Kansas City.

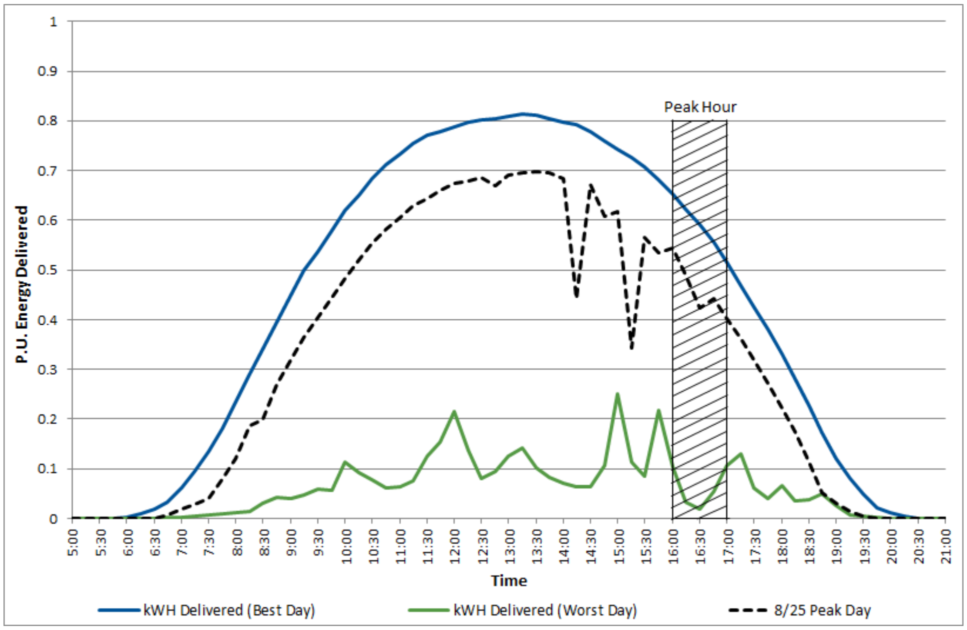
Further analysis showed that the energy consumed by the PV inverter when it was not generating energy was relatively insignificant. On average, the PV systems consumed 3.1 kWh annually for each kW of solar generation capacity. Additionally, the micro-inverter installation consumed only 1.2 kWh annually for each kW of solar capacity, less than half of the consumption at traditional central inverter installations.

Understanding the coincidence of solar generation to the KCP&L load profile and system peak was one of the key objectives of the Distributed Rooftop Solar Generation demonstration and analysis. The KCP&L annual system peak typically occurs between 4 PM and 5 PM in July or August. Analysis shows that solar generation in the Kansas City area would only contribute 40% to 55% of its solar rating at system peak. If a system peak event occurred in early July, solar coincidence as high as 55% may be expected. But as system peak events occur later in the year, the coincidence would be reduced – to 40% by late August.

One of the key objectives of the Distributed Rooftop Solar Generation demonstration and analysis was to understand the solar generation characteristics in Kansas City and to develop a composite per-unit solar generation load profile that could be used to incorporate the impact of solar generation on customer-, circuit-, and system-level analysis. The composite solar energy production load curve that was developed indicates that each1.0 kW-DC of solar PV would produce 1,396 kWh annually, 0.5% more than estimated by the PV Watts Calculator. That would produce an annual production load factor of 15.94%, of which 145 kW, or approximately 10% of its annual production, would be produced during peak residential usage times (4 PM-8 PM).

Below, Figure 3-146 illustrates the best, worst, and summer peak day solar generation production curves based on the composite production model. The figure shows that based on the composite generation profile, a solar generation system would have contributed, on average, 47.5% of its solar rating during the 2014 system peak hour on August 25. This factor can be used for estimating coincidence in an hourly energy market. However, for capacity (kW) planning purposes it is evident that the solar capacity contribution drops off significantly during the peak hour. At 4 PM the solar capacity of a site would be 53.9% of its solar rating, and at 5 PM the capacity would be reduced to 42.2% of its rating. Because the solar capacity varies so significantly based on the time of year and on time of day, one must be careful to select the appropriate capacity coincidence factors for the analysis being performed.

Figure 3-146: Composite Best, Worst and Summer Peak Day Profile



3.4.8.1.3.2 Expectations vs. Actuals

The following table provides a comparison of the Expected Results and the Actual Outcomes for the Distributed Rooftop Solar Generation operational test.

Table 3-106: Expected Results vs. Actual Outcomes

Expected Results	Actual Outcome
• Determine the percent of nameplate that solar generation systems in Kansas City could be expected to produce and verify the annual kWh solar production estimates produced by the NREL PVWatts Calculator.	• Determined that, on average, solar generation would provide, at maximum production, 84% of its solar rating, and validated the NREL PVWatts Calculator solar production estimates.
• Determine the coincidence of solar generation with system annual peak, expressed as a percentage solar generation nameplate rating.	• Determined that the coincidence of solar generation with KCP&L system peak could range from 40% to 55%, depending on when in July or August the peak occurs.
• Development of a composite per unit solar generation profile for customer-, circuit-, and system-level analysis.	• Developed a composite 15-minute per unit solar generation profile.
• Determine the go-forward viability of a leased rooftop business model for utility-owned distributed solar generation.	• Determined that the project's prepaid rooftop lease model encumbered the property and added too many complications for most property owners. Less-restrictive alternative models should be explored.

3.4.8.1.3.3 Computational Tool Factors

The following table lists the values derived from the Distributed Rooftop Solar Generation operational test analysis that will be used as inputs to the SmartGrid Computational Tool.

Table 3-107: Computational Tool Values

Name	Description	Value
Annual Distributed Generation Production (MWh)	The annual amount of generation produced by distributed generation sources.	246.5 MWh
Distributed Generation Use at Annual Peak Time (MW)	The amount of distributed generation capacity available to meet annual peak demand.	0.0745 MW
Reduced Annual Generation Cost	Reduced total cost of producing or procuring electricity to serve load.	$9,399
Reduced CO_2 Emissions (tons)	CO_2 emissions from central generating sources	221.78 tons
Reduced SOx Emissions (tons)	Sox emissions from central generating sources	0.3144 tons
Reduced NOx Emissions (tons)	NOx emissions from central generating sources	0.2365 tons
Reduced $PM_{2.5}$ Emissions (tons)	$PM_{2.5}$ emissions from central generating sources	0.00252 tons

- Distributed Generation Use at Annual Peak Time (MW) – Based on the composite solar generation hourly production coincident with the demonstration's 2014 system peak hour, this value is calculated as follows:

  (176.6 kW x 42.2 %) ÷ 1,000 kW/MW = 0.0745 MW

- Annual Distributed Generation Production (MWh) – Based on the demonstration's composite solar generation production model, this value is calculated as follows:

  (176.6 kW x 1,396 kWh/kW) ÷ 1,000 kWh/MWh = 246.5 MWh

- Reduced Annual Generation Cost ($) – Based on the average hourly generation production costs for 2013 this value is calculated as follows:

  Annual Distributed Generation Production (MWh) x Avg. Daytime Generation Cost-6 AM -8 PM ($/MWh)

  246.5 MWh x $38.13/MWh = $9,399

- Reduced CO_2, SOx, NOx, and PM-2.5 Emissions (tons) – Based on the factors derived from the 2010 emission values contained in the 2014 update of the DOE Emissions & Generation Resource Integrated data base for the SPP North subregion, these values are calculated as follows:

  CO2 Emissions – Annual Distributed Generation Production (MWh) x (lbs CO_2/MWh) ÷ (lbs/ton)

  246.5 MWh x 1,799.45 lbs CO_2/MWh ÷ 2,000 lbs/ton = 221.78 tons CO_2

  SOx Emissions – Annual Distributed Generation Production (MWh) x (lbs SOx/MWh) ÷ (lbs/ton)

  246.5 MWh x 2.5511 lbs SO_2/MWh ÷ 2,000 lbs/ton = 0.3144 tons SOx

  NOx Emissions – Annual Distributed Generation Production (MWh) x (tons NOx/MWh)

  246.5 MWh x 1.9186 lbs NOx/MWh ÷ 2,000 lbs/ton = 0.2365 tons NOx

  $PM_{2.5}$ Emissions – Annual Distributed Generation Production (MWh) x (tons PM2.5/MWh)

  246.5 MWh x 0.00001022 tons $PM_{2.5}$/ MWh = 0.00252 tons $PM_{2.5}$

  Where: ton $PM_{2.5}$/MWh =

  12.27 MMBTU/MWh ÷ 19.21 MMBTU/ton-coal x 0.000016 ton $PM_{2.5}$/ton coal = 0.00001022

3.4.8.1.4 Lessons Learned

Throughout the conduct of the operational testing and analysis of the Distributed Rooftop Solar Generation function, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- Any agreements for siting utility-owned solar generation on customer property should be structured in a manner that does not create unmanageable property encumbrances for current and future owners.
- NREL's New PVWatts Calculator, released in the fall 0f 2014, provides very credible estimates for sites in and around Kansas City. It estimates that a rooftop solar installation in Kansas City will produce 1,389 W-AC per kW-DC annually for an annual solar production load factor of 15.85%.
- This analysis determined that that the coincidence of solar generation with the KCP&L system peak could range from 40% to 55%, depending on when in July or August the peak condition occurs. If a system peak event occurs in early July, solar coincidence as high as 55% may be expected. But as peak events occur later in the year, the coincidence reduces – to 40% by late August.

3.4.9 Storing Electricity for Later Use

Remote control of electricity storage (ES) inflow/outflow reduces energy costs and enhances power generation and transmission and distribution capacity utilization. The following sections present information regarding electricity storage function operational tests, analysis, and results.

3.4.9.1 Electric Energy Time Shift

The Electric Energy Time Shift application involves storing electricity when the price of electricity is low and discharging that electricity when the price of electricity is high. The energy that is discharged from the energy storage could be sold via the wholesale market, sold under terms of a power purchase agreement, or used by an integrated utility to reduce the overall cost of providing generation during peak times.

3.4.9.1.1 Overview

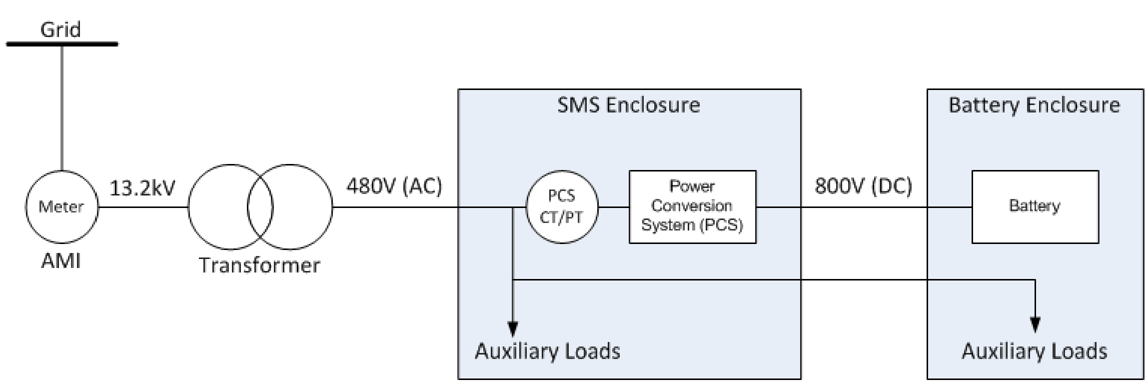
The following sections provide an overview of the operational demonstration, testing, and evaluation methodology used for the Energy Time Shift operational test.

3.4.9.1.1.1 Description

A 1.0 MW/1.0 MWh-capable, grid-connected Battery Energy Storage System has been installed adjacent to the Midtown Substation with direct interconnect to a single 13.2-kV circuit. A daily charge and discharge cycle was implemented to demonstrate and evaluate the operational benefit of using the BESS for the electric energy time shift application.

Figure 3-147 shows the interconnection of BESS to the utility grid. The AMI meter is connected on the high side (13.2-kV) of the BESS distribution transformer and records the 15-minute interval data of energy received and delivered by the BESS. The BESS distribution transformer steps down the 13.2-kV to 480-V AC. The 480-V network then supplies power to auxiliary loads such as those for air conditioning, lighting, control systems, etc. in the battery and SMS enclosures. The SMS uses the Power Conversion System (PCS) electronics to convert AC voltage to DC voltage and vice versa. The PCS control CTs and PTs in the SMS enclosure record data of power output of PCS and battery combined, at 10-second intervals. The SMS connects to the battery through an 800-V DC line.

Figure 3-147: Battery-Inverter Interconnection



3.4.9.1.1.2 Expected Results

The operational demonstration of the grid connected battery in this application was expected to yield the following:

- The BESS would operate at greater than 70% efficient with respect to net energy output versus input.
- The PCS and battery combined round trip AC-AC efficiency would be approximately 85%. (EPRI Case Study – KCP&L Grid-Connected Battery, November 2012, PureWave Community Energy Storage System – S&C)
- Utility electric production costs could be reduced by charging the battery with low cost Off-Peak energy and discharging it at higher cost production times.

3.4.9.1.1.3 Benefit Analysis Method/Factors

The SGCT and ESCT identified the following benefits derived from energy storage systems ability to offset Energy Time Shift.

Figure 3-148: Benefits of Energy Time Shift

				Utility/Ratepayer						Societal			
Location	Market	Owner	Application	Optimized Generator Operation	Deferred Generation Capacity Investments	Deferred Transmission Investments	Deferred Distribution Investments	Reduced Electricity Losses	Reduced Electricity Cost	Reduced CO2 Emissions	Reduced SOx Emissions	Reduced NOx Emissions	Reduced PM Emissions
Distribution	Regulated	Utility	Electric Energy Time-shift	AB	AB		AB	AB	PB	SB	SB	SB	SB

Note: Primary benefits (PB) are quantified in this section. Secondary benefits (SB) and additional benefits (AB) will be addressed in later sections.

The DOE SGCT was used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits were quantified.

- Optimized Generation Operation

Benefits were calculated using SGCT formulas. The following factors was measured, projected, or calculated during the application operation and/or demonstration.

Optimized Generation Operation

- (Reduced) Annual Generation Cost ($)

Additionally, the DOE ESCT was used to perform the benefit analysis for a utility owned GES system. The following Stationary Energy Storage applications were combined in this analysis.

- Primary Application – Electric Energy Time Shift
- Secondary Application – Electric Supply Capacity
- Secondary Application – T&D Upgrade Deferral

ESCT Primary Benefit for Electric Energy Time Shift:

- Reduced Electricity Costs (Utility/Ratepayer)

3.4.9.1.1.4 Testing Methodology

The following points provide an overview of how the operational demonstration and testing for this application was accomplished:

- Energy delivered to and received from the BESS was measured on the high side of the BESS interconnection transformer through the AMI system deployed as part of the project. All AMI data collected were stored in KCP&L's MDM and DMAT systems.
- Energy delivered to and received from the PCS (and battery) was measured in the SMS HMI utilizing the PCS CTs/PTs. All the data collected were stored in the SMS HMI.
- A weekly daily charge/discharge cycle was implemented to demonstrate and evaluate the operational benefit of using the battery for electric energy time shift applications. Charging occurred daily from 1-6 AM and discharge occurred from 3-7 PM.
- Individual seasonal testing and data collection periods were conducted to evaluate the potential impact of seasonal auxiliary loads on overall BESS efficiency.

3.4.9.1.1.5 Analytical Methodology

The following points provide an overview of the analytical methods that were used to evaluate the impact and benefits of this application:

- AMI 15-minute interval load data for the BESS were extracted from the KCP&L's DMAT.
- 10-second interval data of the PCS were extracted from the SMS HMI.
- The 10-second interval data of the PCS were converted to 15-minute interval data for comparison with the 15-minute interval AMI data.
- The DMAT has built-in functionality that enabled calculation of the following hourly load profiles:
  - BESS Energy Discharged to grid.
  - BESS Energy Received from grid.
- The Daily Round Trip Efficiency of PCS and battery was calculated as (Daily Energy Delivered from the PCS and battery/Daily Energy Received by PCS and battery).
- The Daily Round Trip Efficiency of BESS was calculated as (Daily Energy Delivered to the grid/Daily Energy Received from the grid).
- An annual daily charge/discharge profile for the BESS was constructed using the DMAT load profile and temperature data for the application operational testing periods.
- The Annual BESS Efficiency was calculated as (Annual BESS Energy Delivered to the grid/Annual BESS Energy Received from the grid).
- The Annual Reduced Utility Electricity Cost will be calculated by the Smart Grid Computational Tool and Energy Storage Computational Tool in subsequent sections.

3.4.9.1.2 Plan Execution and Analysis

The following sections provide details regarding the functional tests performed, data collected, and analysis performed for the Energy Time Shift operational test.

3.4.9.1.2.1 Daily Charge and Discharge Operation

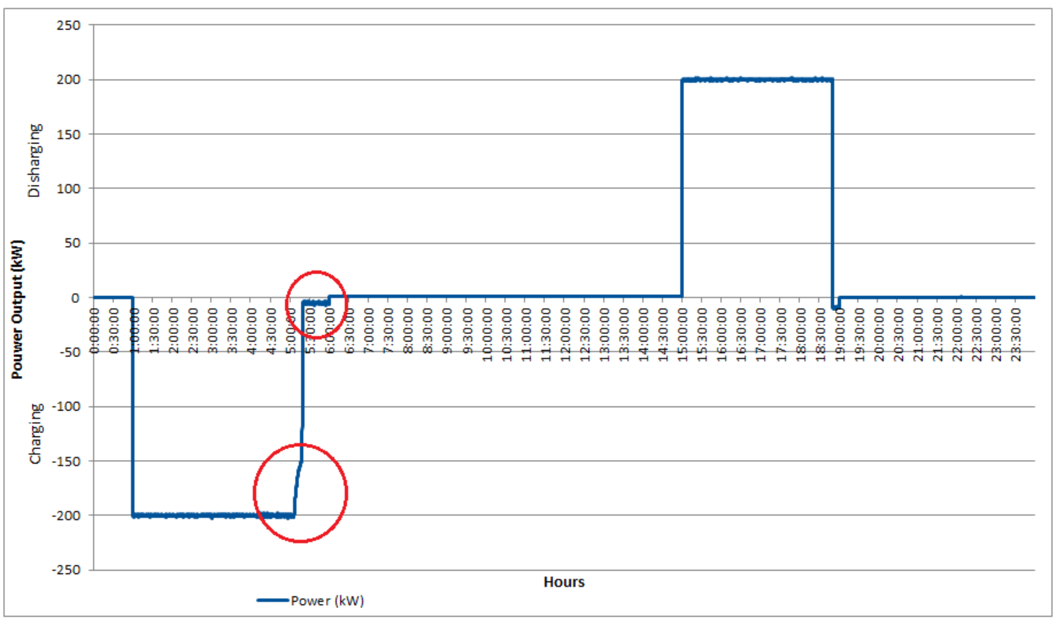
A review of the manufacturer's operation manual identified a recommendation that the battery should not be routinely discharged below a 20% charge level to protect the battery and maintain its useful life. This operational constraint limits the output of the 1.0 MWh Lithium polymer battery to 800 kWh from a full charge.

The BESS was set to charge daily from 1 AM to 6 AM and discharge from 3 PM to 7 PM local time. This coincides with the system and residential peak load times and is consistent with the TOU peak pricing time period. To achieve a full charge and discharge, the following settings were configured in the SMS:

- The PCS discharge rate was set to 200 kW to deliver approximately 800 kWh during the 4-hour discharge period.
- The PCS charge rate was set to 200 kW to provide a full charge, up to 1 MWh, during the 5-hour charge period.
- The PCS State of Charge (SOC) threshold was lowered from 20% to 15%. This allowed the battery to discharge beyond the recommended discharge limit to see that the PCS could achieve the scheduled discharge throughout the required discharge period.
- The PCS Ramp Rate was set to 20 kW/second. With this setting it took 10 seconds to ramp up charge, or ramp up discharge, to the set power of 200 kW.
- Per manufacturer's recommendation for optimum performance of the PCS and battery modules, the internal temperature setting of the SMS and Battery enclosure was set to:
  - 68^{o} F for heat setting
  - 70^{o} F for cool setting

Figure 3-149 shows the 10-second interval daily charge and discharge cycles under these settings. The SMS HMI records 10-seconds gross output value of the PCS and battery combined on the AC side of the PCS.

Figure 3-149: Daily Charge and Discharge Cycle of PCS and Battery Combined



As illustrated in the figure above, the SMS lowers the charging current to protect the battery from overcharging. The circled areas in the figure show how the SMS reduces the charge rate as the battery approaches the full charge state and then the "trickle" charging at the end of charging cycle.

During the BESS charge cycle and nonoperational or idle periods, the AMI metering records the power the BESS receives from the grid, including all auxiliary loads and power (recorded by the SMS HMI) to charge the battery. During the discharge cycle, the AMI metering records the power the BESS delivers to the gird. The AMI-recorded discharge power is less than the discharge power recorded by the SMS HMI because the auxiliary loads are now supplied by the output of the PCS. Due to the auxiliary power source shifting during the discharge cycle, the net impact on the grid is measured at the SMS HMI and not the AMI metering. This is depicted in Figure 3-150 which shows the AMI metering and the PCS metering from the SMS HMI for a daily charge/discharge cycle.

Figure 3-150: Daily 15-Minute Charge and Discharge Cycle from AMI and SMS

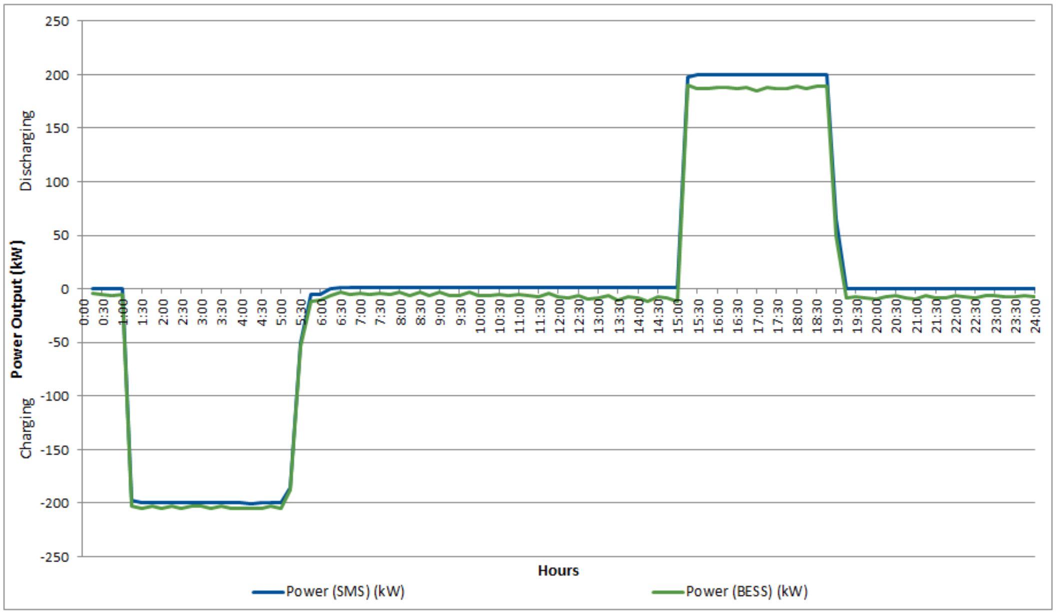
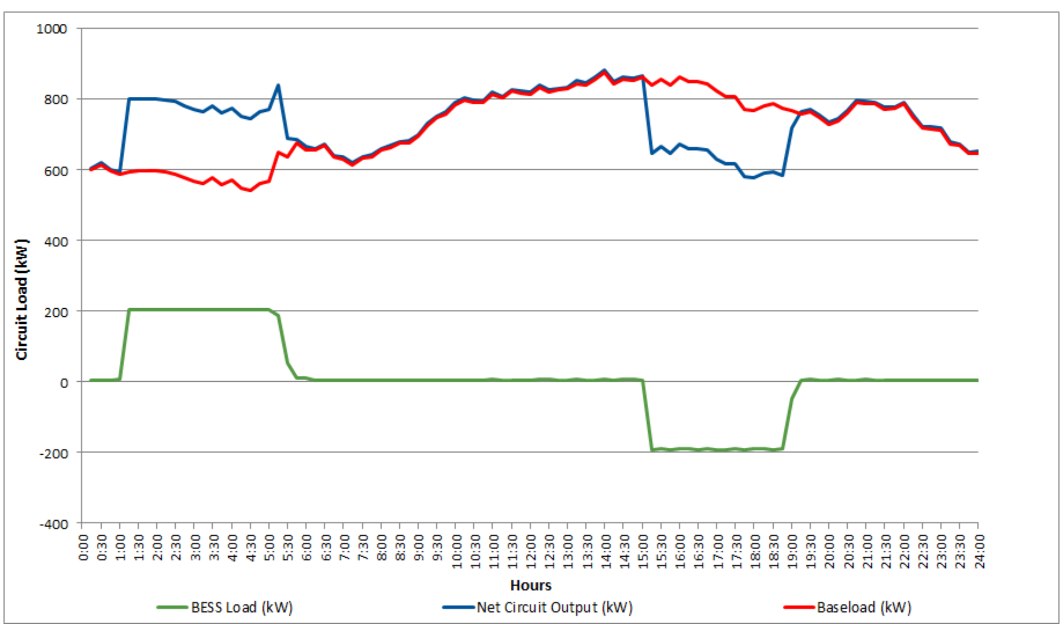


Figure 3-151 shows the net impact in the circuit from the BESS daily charge and discharge cycle.

Figure 3-151: Net Battery and Circuit Load Profile



3.4.9.1.2.2 Daily Round Trip Efficiency of PCS and Battery Combined

At the beginning of the project, it was anticipated that the efficiency of PCS and battery combined would be about 85%. During the Site Acceptance Test, the efficiency of battery was measured to be 92%. With the projected PCS efficiency of 96% (902836 SMS Guide Specification Rev 4.pdf), the efficiency of PCS and battery combined is expected to be about 88%. The purpose of this analysis is to verify the efficiency of the PCS and battery combined.

The round trip efficiency of the PCS and battery is calculated as follow:

$$RTE\ of\ PCS - Battery\ combined = \frac{Energy\ Delivered\ by\ PCS\ \&\ Battery}{Energy\ Received\ by\ PCS\ \&\ Battery} \times 100\%$$

Table 3-108 shows the energy required to charge the battery, energy discharged by the battery and the corresponding round trip efficiency after the CT positions were changed. These values were measured over many days and random dates were selected for inclusion in the table to illustrate the daily variation of the test results. The RTE of the PCS and battery combined when calculated as an average of all daily tests is 89.81%.

Table 3-108: Daily Round Trip Efficiency of PCS and Battery Combined

Date	Energy from PCS & Battery (kWh)	Energy to PCS & Battery (kWh)	Efficiency (%)
5/3/2014	772.97	860.59	89.82%
5/13/2014	765.06	858.46	89.12%
5/20/2014	769.56	857.51	89.74%
6/2/2014	770.81	860.63	89.56%
6/10/2014	772.97	860.60	89.82%
6/27/2014	771.48	860.13	89.69%
7/5/2014	771.36	858.22	89.88%
7/14/2014	755.13	843.68	89.50%
7/22/2014	768.95	857.57	89.67%
7/26/2014	772.52	856.29	90.22%
7/30/2014	774.16	852.88	90.77%
8/8/2014	773.33	861.14	89.80%
8/13/2014	768.81	856.96	89.71%
8/18/2014	766.90	860.85	89.09%
8/26/2014	772.17	862.21	89.56%
Average of all samples			**89.81%**

Based on system specification documents provided by the vendors at project initiation, the battery was rated at 90% efficiency and the PCS was rated at 95% efficiency. As a result, the expected efficiency of the PCS and battery combined was 86.4%.

During the Site Acceptance Test the round-trip efficiency of battery was measured to be 92%. Therefore, with a measured average efficiency for the PCS and battery combined of 89.81%, the actual PCS efficiency can be calculated as 97.6%. Table 3-109 below shows the efficiency of the PCS, the battery, and then the PCS and battery combined.

Table 3-109: Efficiency of PCS and Battery

Component	Specification	Actual
Battery	90.0%	92.0%
PCS	96.0%	97.6%
PCS and Battery Combined	86.4%	89.8%

3.4.9.1.2.3 Daily Round Trip Efficiency of the BESS

At the beginning of the project, it was expected that the BESS would operate at efficiency greater than 70% with respect to net energy output versus input. The AMI records the power received from and delivered to the battery along with the power delivered to the auxiliary loads and the losses in the PCS and distribution transformer. Hence, the overall system or BESS efficiency is lower than that of the PCS and battery combined. The purpose of this analysis is to verify the round-trip efficiency of BESS.

Based on the daily charge and discharge cycle, the round trip efficiency of the BESS is calculated as:

$$RTE\ of\ BESS = \frac{Energy\ Recieved\ by\ BESS}{Energy\ Delivered\ by\ BESS} \times 100\%$$

Early in the recordings and monitoring, the project team saw significant daily variation in efficiency and found correlation with the average daily temperature. Therefore, the project team analyzed the daily change in efficiency based on the temperature. Table 3-110 shows the energy delivered by the grid to charge the BESS, energy discharged by the BESS, and variation of round-trip efficiency with temperature. These values were measured during many days and test data were selected for inclusion in the table to illustrate the variation of the test results based on temperature. Details will be provided in the next section.

Table 3-110: Daily Round Trip Efficiency of the BESS

Daily Average Temperature (F)	Energy from BESS (kWh)	Energy to BESS (kWh)	Efficiency (%)
2	699.16	1118.18	62.52%
7	722.12	1071.56	67.39%
12	719.00	1056.00	68.09%
19	724.36	1044.12	69.38%
23	721.70	1025.36	70.39%
28	724.78	1013.74	71.50%
32	727.81	994.32	73.20%
36	738.36	975.94	75.66%
41	734.72	958.30	76.67%
47	731.22	949.34	77.02%
53	736.96	936.32	78.71%
59	732.06	948.78	77.16%
63	737.38	944.44	78.08%
70	718.90	947.66	75.86%
77	724.64	980.88	73.88%
82	719.93	996.43	72.25%
85	710.78	1010.66	70.33%
Average of all samples			**74.66%**

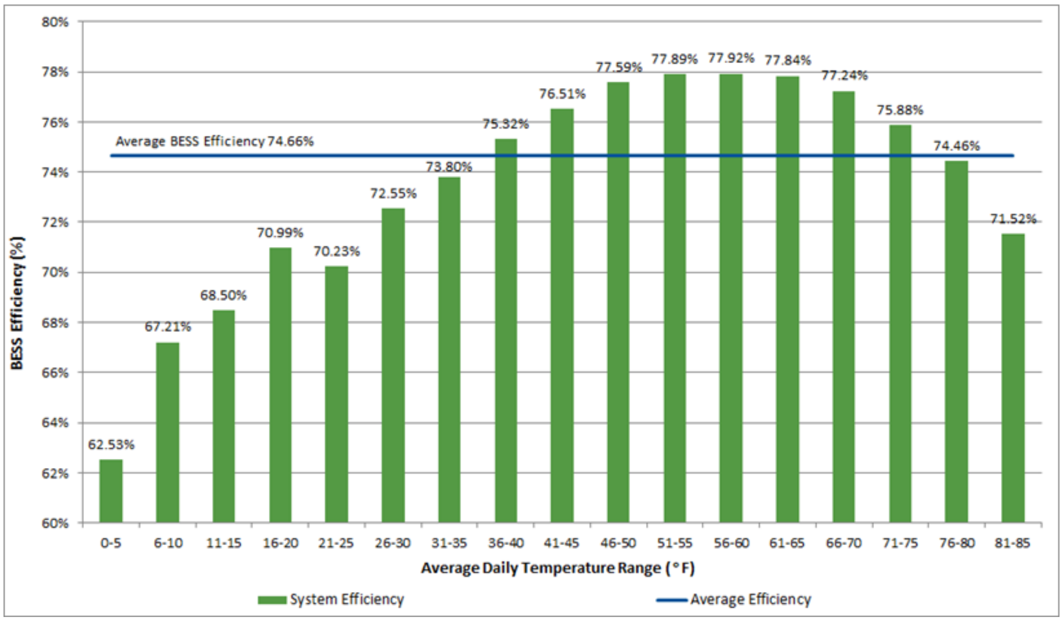
The daily round-trip efficiency varied from 62% when the average temperature was 2° F, to a maximum of 78%, when the average temperature was between 53° F and 63° F. During the analysis, it was noted that as the temperature increased beyond 63° F, the efficiency of the BESS decreased.

3.4.9.1.2.4 Round Trip Efficiency versus Temperature

In analyzing the daily round-trip efficiency of BESS, it was found that the efficiency of BESS correlated to the daily average temperature. A graph of daily efficiency with respect to the daily average temperature was plotted to understand the correlation. Figure 3-152 shows the BESS efficiency with respect to the daily average temperature.

The figure shows that at lower average temperatures, the RTE of BESS was lower. As the temperature increased, the RTE of BESS increased. The RTE of BESS reached its maximum when the average temperature of the day was between 50° F to 65° F. And as the temperature increased further, the RTE of BESS started to decrease. Figure 3-7 also shows that the average of all BESS daily efficiency samples was 74.66%. The highest round trip efficiency of 78.71% for BESS was achieved when the average daily temperature was 53° F.

Figure 3-152: BESS Efficiency with Respect to Daily Average Temperature



The lower efficiency on days with lower and higher average temperatures is due to the heating and cooling systems running frequently to maintain the temperature in the enclosure. During the winter the heating system was running frequently to maintain 68° F in the battery and PCS enclosure, while during the summer the cooling system was maintaining the indoor temperature of 70° F. When the daily average temperature was between 55° F and 65° F, the heating and cooling system did not have to operate frequently to maintain the indoor temperature.

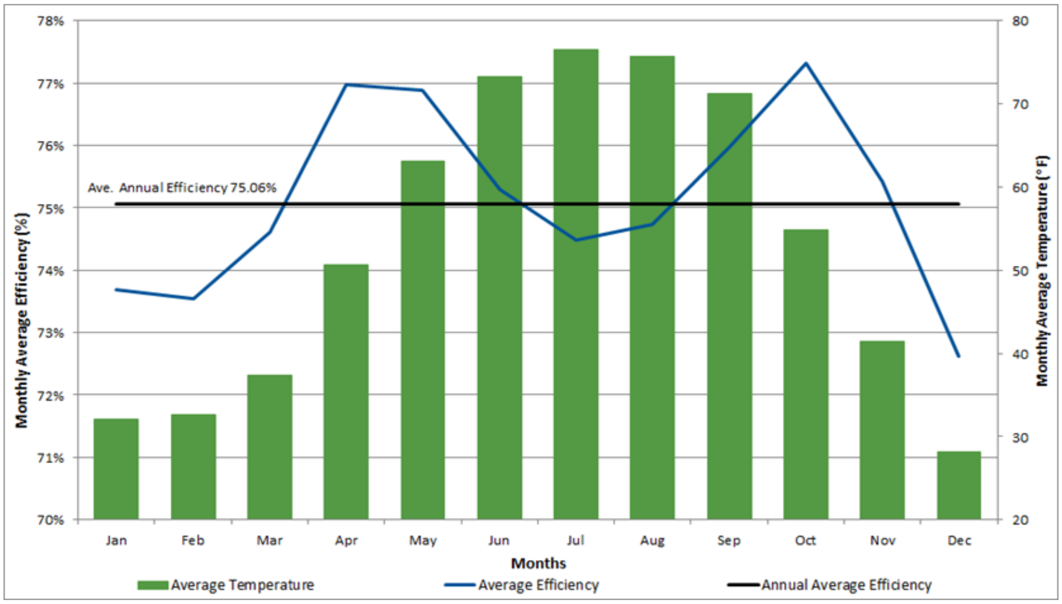
3.4.9.1.2.5 Annual Round-Trip Efficiency of BESS

During the operational test period the BESS could not be dedicated for daily charge and discharge cycle due to maintenance, post-implementation operational issues, and various other BESS and SGDP testing. The BESS was scheduled for daily charge and discharge whenever possible. The 15-minute interval data of energy required to charge and energy discharged by the BESS were collected by the AMI and stored in the DMAT along with the 15-minute interval temperature data. An average energy delivered from and to the BESS for each daily temperature was then calculated.

An annual BESS charge/discharge profile for2013 was constructed by populating any missing daily energy delivered from and to the BESS using these values and the recorded average daily temperature. This way, values were determined for energy delivered by BESS and energy delivered to BESS for entire 365 days of 2013.

Figure 3-153 shows the average monthly temperature and the corresponding round-trip efficiency of the BESS.

Figure 3-153: BESS Efficiency with Respect to Average Monthly Temperature for 2013



As indicated in the figure, the efficiency of BESS decreased in periods of higher and lower temperatures, indicating the need for improved insulation and more-efficient HVAC units on the SMS and battery enclosures.

Based on the daily energy charge/discharge profile constructed for 2013, the annual total energy supplied by the grid to the BESS was calculated to be 355.29 MWh, and the annual total energy delivered to the grid by the BESS was calculated to be 266.68 MWh, resulting in annual round-trip efficiency of 75.06%. The annual RTE of 75.06% was slightly better than the 74.66% average of daily samples and considerably better than the 70% RTE originally anticipated for the BESS.

3.4.9.1.2.6 Issues and Corrective Actions

The following issues and corrective actions were encountered during performance of the Energy Time Shift operational testing and analysis.

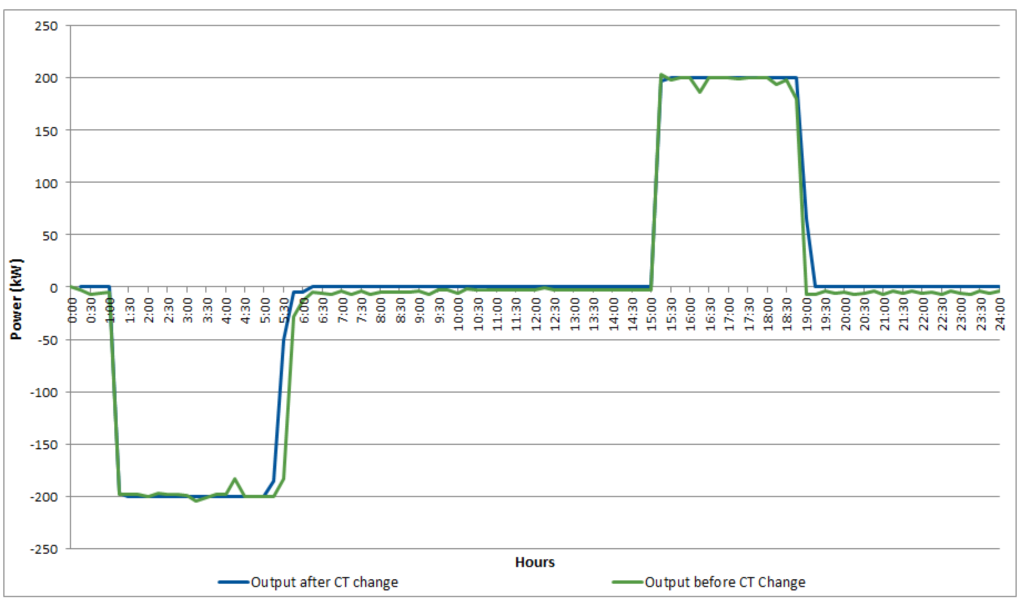
Table 3-111: Issues and Corrective Actions

Issue	Corrective Action
• Manufacturer operating guideline that battery should not be routinely discharged below 20% of rating.	• Limited scheduled BESS discharge to 800 kWh.
• The SMS HMI was connected to AMI metering to facilitate “islanding” re-sync. This distorted control of PCS output with auxiliary loads.	• The SMS HMI was changed to internal (480V line) PCS CT/PTs. • This allowed SMS to control PCS based on output of PCS only.
• In analyzing 10-second interval data, it was found that there were spikes in PCS and battery power output every 2 hours. The spikes and dips were caused by a 6-	• RTAC (Real Time Automation Controller) was programmed to stop requesting time sync with SMS. • The logic was also changed in RTAC to set SMS in

hour (5 hours during DST) time shift in SMS data. (Issue A below)	UTC zone, and to set the rest of the system in CST with DST enabled.
• Fluctuation in the PCS and battery output during the charging cycle. The output looked similar to "Fuller Brush." (Issue B below)	• The vendor, S&C, changed the regulator settings in SMS. • Fine tuning settings in SMS made the output smooth.
• Output of PCS and battery varied up to 15 kW during nonoperational period. (Issue C below)	• A thorough check of connections revealed that some auxiliary loads were connected on the PCS side of the PCS CT/PTs. • The auxiliary loads were reconnected to the grid side of the PCS CT/PTs.
• Frequently recurring under voltage alarm in Battery Management System and SMS.	• The vendor, Kokam, placed ferrites in DC cables and verified grounding to eliminate high-frequency noises.
• Toward the end of discharge cycle, the PCS and battery output showed that the battery charged for 10 minutes. (See Figure 3-13.)	• The vendor, S&C, made necessary changes in the SMS settings to eliminate charge during the discharge cycle.

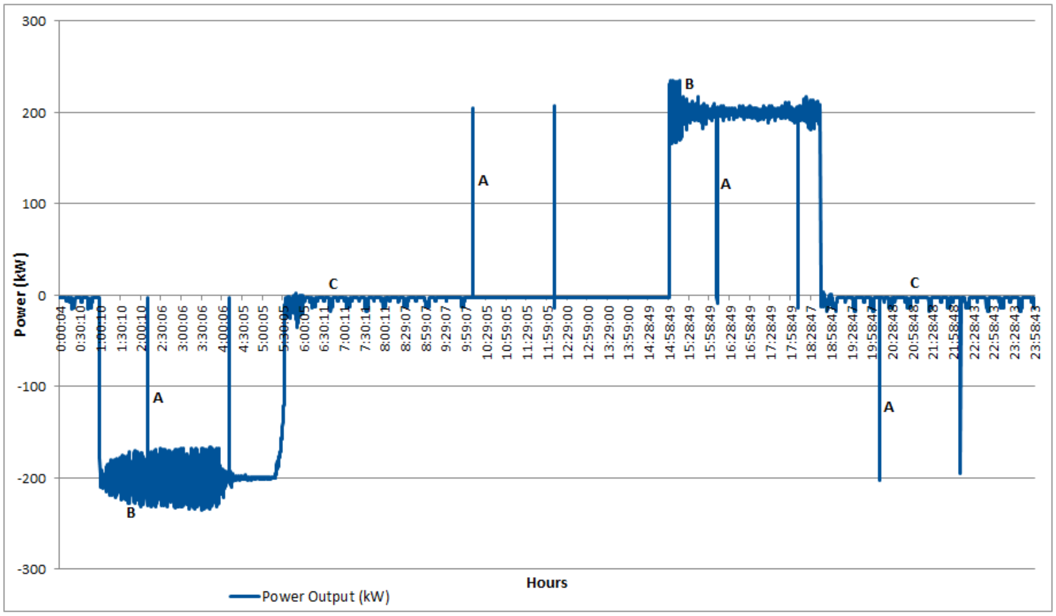
The CTs/PTs used for the SMS PCS HMI was initially connected to the BESS 13.2-kV metering CTs/PTs on the high side of the distribution transformer to aid in synchronized recovery from islanding. This caused SMS to capture the output of the battery and inverter, along with the power consumed by the auxiliary loads and transformer losses. After the SMS PCS HMI connection was changed to the internal SMS CT/PT on the source side of the PCS, the data recorded by the SMS should have included the output from the battery and inverter only. Figure 3-154 shows the output from SMS before and after the CTs/PTs were changed. It can be seen that the output was smoother and appeared to exclude the auxiliary loads.

Figure 3-154: PCS and Battery Output before and after CT Change



Further inspection of the SMS PCS 10 second interval output data identified several additional issues. Figure 3-155 shows the 10-second interval output of battery inverter combined and illustrates the issues mentioned above.

Figure 3-155: PCS and Battery Power Output with Issues



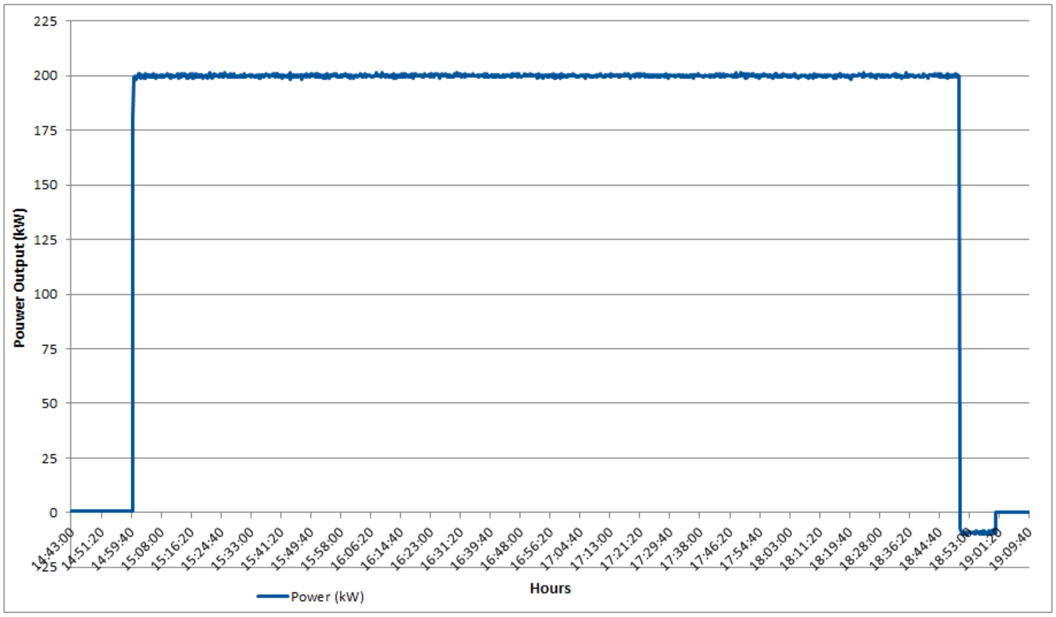
Issue A – "Spikes": The power output of the PCS and battery dropped to zero during charge and discharge period and spiked to 200 kW during the idle period. Upon examination, it was determined that these spikes were occurring every two hours and caused a 6-hour time-shift (5-hour time shift during daylight savings time) in SMS data. It was found that the Real Time Automation Controller (RTAC) was syncing its time with SMS every 2 hours. Since the SMS was in Universal Time Coordinated (UTC) zone and RTAC in local Central time zone, the RTAC was requesting time sync with SMS and caused a 5-/6-hour time shift. The RTAC code was adjusted to set SMS in UTC, and logic was changed to stop time syncing every 2 hours.

Issue B – "Fuller Brush" Effect: The output of PCS and battery was fluctuating during the charging and discharging period. During the charge cycle, the output fluctuated for first few hours and then settled after that, resembling "Fuller Brush." During the discharge cycle, the output fluctuated the entire discharge period. The vendor changed the regulator setting in the SMS and fine-tuned the settings, resulting in a stable output.

Issue C – High Power Consumption during idle period: The auxiliary loads – such as HVAC, lighting, control systems, etc. – is supplied by the grid during the charging and idle period and supplied by the battery during the discharging period. After the PCS control CTs/PTs were changed to the internal 480-V line, the SMS HMI still showed some abnormal usage during idle times. When the auxiliary load connections were checked, it was found that some were connected between the PCS and PCS control CTs/PTs. The auxiliary loads were reconnected to the grid side of the PCS CTs/PTs.

After the CT position change, the adjusted wiring and fine-tuning of the regulator setting, the output of the PCS and battery was monitored and reviewed. It was found that at the end of discharge cycle, the battery charged for 10 minutes at 8 kW to 10 kW. The vendor made setting changes in SMS to eliminate this issue.

Figure 3-156: Last 10 Minutes of Charging during Discharge Cycle



3.4.9.1.3 Findings

The results obtained in the execution and analysis of the Energy Time Shift operational testing are summarized in the sections below.

3.4.9.1.3.1 Discussion

The 1.0 MW/1.0 MWh grid-connected BESS is set to operate on fixed charge/discharge schedule whenever possible. The BESS was scheduled to charge for 5 hours, from 1 AM to 6 AM local time (a minimum system load period); and discharge for 4 hours, from 3 PM to 7 PM local time, which coincides with residential peak load and the TOU peak-pricing time period. Since the BESS is only capable of discharging 80% of its rated storage capacity, the battery was set to discharge 200 kW/Hr for 4 hours, a total of 800 kWh.

During the BESS Site Acceptance Test and the daily RTE testing conducted under this operational test plan, the efficiencies of the BESS and its major components were measured or calculated. The table below provides a summary comparison of these findings and the original project or manufacturer component specifications. In all cases, the products' field efficiency performance was better than the product/project specification.

Component	Specification	Actual
Battery	90.0%	92.0%
PCS	96.0%	97.6%
PCS and Battery Combined	86.4%	89.8%
BESS (Annual)	70.00%	75.06%

Critical for this analysis was understanding where auxiliary loads were connected and how the SMS HMI controlled the PCS, and thus the output of the BESS. The SMS HMI controlled the PCS based on the PCS CTs/PTs located on the AC side of the PCS. Because the net impact to the grid during discharge was measured at the PCS CTs/PTs, the energy rating of the BESS should be further reduced from the battery vendors 80% derating, to factor in the PCS efficiency. The 1.0 MWh hour battery can only deliver a 780-kWh. (1,000 x 80% x 97.6% = 780) net impact to the grid on a routine basis.

During the analysis, it was found that the daily RTE of BESS varied significantly with a correlation to the average daily temperature. The daily RTE varied from 62%, when the average daily temperature was 2° F, to a maximum of 78.7%, when the average daily temperature was 53° F. The average of all daily RTE samples was 74.6%. Above-average RTEs were achieved when daily average temperatures were between 35° F and 75° F, but the best RTEs were achieved between 50° F and 65° F. This suggests that the average RTE of BESS may be improved by focusing on the auxiliary loads and installing improved insulation and more-efficient HVAC units on the SMS and battery enclosures.

Using the energy charge/discharge profile constructed for 2013, based on the recorded daily average temperature, the annual total energy supplied by the grid to the BESS was calculated to be 355.29 MWh, and the annual total energy delivered to the grid by the BESS was calculated to be 266.68 MWh, resulting in annual round trip efficiency 75.06%. The annual RTE of 75.06% was slightly better than the 74.66% average of daily samples and considerably better than the 70% RTE that originally had been anticipated for the BESS.

3.4.9.1.3.2 Expectations vs. Actuals

The following table provides a comparison of the Expected Results and the Actual Outcomes for the Energy Time Shift operational test.

Table 3-112: Expected Results vs. Actual Outcome

Expected Results	Actual Outcome
• The system is expected to operate at greater than 70% efficient with respect to net energy output versus input.	• The annual average BESS efficiency was calculated to be 74.58%, which is higher than expected.
• The PCS and battery combined round trip AC-AC efficiency was expected to be greater than 85%.	• The efficiency of the PCS and battery combined was calculated to be 89%, higher than expected.
• Utility electric production costs will be reduced by charging the battery with low cost Off-Peak energy and discharging it at higher cost production times.	• With an annual RTE of 75%, it was determined that for any energy time shift savings to occur, the average daily Off-Peak energy cost must be less than 75%.

3.4.9.1.3.3 Computational Tool Factors

The following table lists the values derived from the Energy Time Shift operational test analysis that will be used as inputs to the SmartGrid Computational Tool and the Energy Storage Computational Tool.

Table 3-113: Computational Tool Values

Name	Description	Value
Total Energy Discharged for Energy Time Shift (MWh)	The total amount of energy discharged from the energy storage device and used for arbitrage purposes during a year.	266.68 MWh
Electric Storage Efficiency (%)	Ratio of total energy discharged to total energy charged.	75.06%
Reduced Annual Generation Cost	Reduced total cost of producing or procuring electricity to serve load.	$2,963.07
Reduced Electricity Costs (Utility/Ratepayer)	Charging energy storage device when demand is low and discharging when demand is high may decrease a utilities energy cost.	$2,963.07

- <u>Reduced Annual Generation Cost ($) –</u> Based on the 2014 hourly energy costs in the SPP Day Ahead Energy Market, this value is calculated as follows:

  Total Energy Discharged for Energy Time-Shift x [Avg. Peak Generation Cost 3-7 PM ($/MWh) – (Avg. Off-Peak Generation Cost 1-6 AM ($/MWh)/Energy Storage Efficiency (%))]

  266.68 MWh x [$41.46/MWh – ($22.78/MWh ÷ 0.7506)] = $2,963.07

- <u>Reduced Electricity Costs (Utility/Ratepayer) ($) –</u> This calculation is the same as the Reduced Annual Generation Cost calculation above.

3.4.9.1.4 Lessons Learned

Throughout the conduct of the operational testing and analysis of the BESS for Energy Time Shift function, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- In the analysis of round-trip efficiency of BESS, it was noticed that the round-trip efficiency of BESS was dependent on the daily average temperature. To improve operational performance of any future BESS implementation, specifications should focus on improving the efficiency of auxiliary loads and installing improved insulation and more efficient HVAC units on the SMS and battery enclosures.
- The placement of auxiliary loads relative to the SMS PCS CTs/PTs is critical for proper control of battery operation. The auxiliary loads must be connected on the grid side of the SMS PCS CTs/PTs so that the SMS is directly monitoring the AC output of the PCS.
- Site acceptance testing needs to include microanalysis of charge/discharge cycles to identify any irregularities and fine-tune the settings to get the desired and smooth power output.
- Due to the nature of lithium ion batteries and inverter, a 1.0 MWh battery is not, functionally, 1.0 MWh battery. The 1.0 MWh battery can only can only deliver a 780-kWh (1,000 x 80% x 97.6% = 780.0) net impact to the grid.
- If the battery had been selectively discharged solely based on SPP locational marginal prices in the day-ahead or real-time markets which were established March 01, 2014, significantly greater economic benefits could have been achieved.

3.4.9.2 Electric Supply Capacity

As demand on the electricity grid grows from year-to-year, the need to install additional generation capacity to meet this demand also grows. The Electric Supply Capacity application involves using energy storage to defer and/or to reduce the need to invest in new generation capacity. In a regulated market, a utility may install a marginal amount of energy storage to meet capacity needs thus deferring the need to invest in a larger conventional generation solution. In a deregulated market, in which the electric supply capacity market is evolving, this application could involve selling energy storage capacity to the market in order to generate a capacity credit revenue stream for a non-utility merchant. However, this market is evolving and in some markets, generation capacity cost is included in wholesale energy prices.

3.4.9.2.1 Overview

The following sections provide an overview of the operational, demonstration, testing, and evaluation methodology used for the Electric Supply Capacity operational test.

3.4.9.2.1.1 Description

A 1.0 MW/1.0 MWh-capable, grid-connected Battery Energy Storage System has been installed adjacent to the Midtown Substation with direct interconnect to a single 13.2-kV circuit. The grid interconnection and internal component connections of the BESS are illustrated in Figure 3-147 and described earlier in the Electric Time Shift Operational Test section. DMS based BESS control functions have been implemented to discharge the BESS during time of peak generation requirements, including:

- Block Discharge Mode for operator-defined fixed discharge
- DERM mode for discharge in response to DR events

3.4.9.2.1.2 Expected Results

The operational demonstration of the grid-connected battery in this application was expected to yield the following:

- Demonstration of controlled operation of battery at time of system peak via operator-initiated events and DERM-initiated DR events.
- Determination of the effective MW peak reduction for a 1.0 MWh battery.

3.4.9.2.1.3 Benefit Analysis Method/Factors

The SGCT and ESCT identified the following benefits derived from energy storage systems' ability to offset Electric Supply Capacity.

Figure 3-157: Benefits of Electric Supply Capacity

				Utility/Ratepayer						Societal			
Location	Market	Owner	Application	Optimized Generator Operation	Deferred Generation Capacity Investments	Deferred Transmission Investments	Deferred Distribution Investments	Reduced Electricity Losses	Reduced Electricity Cost	Reduced CO2 Emissions	Reduced SOx Emissions	Reduced NOx Emissions	Reduced PM Emissions
Distribution	Regulated	Utility	Electric Supply Capacity			PB							

Note: Primary benefits (PB) are quantified in this section. Secondary benefits (SB) and additional benefits (AB) will be addressed in later sections.

The DOE SGCT was used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits was quantified.

- Deferred Generation Capacity Investments

Benefits were calculated using SGCT formulas. The following factors were measured, projected or calculated during the application operation and/or demonstration.

Deferred Generation Capacity Investments

- Energy Storage Use at Annual Peak Time (MW)

Additionally, the DOE ESCT was used to perform the benefit analysis for a utility owned BESS. The following Energy Storage applications were combined in this analysis.

- Primary Application – Electric Energy Time Shift
- Secondary Application – Electric Supply Capacity
- Secondary Application – T&D Upgrade Deferral

ESCT Primary Benefit for Electric Energy Time Shift:

- Deferred Generation Capacity Investment (Utility/Ratepayer)

3.4.9.2.1.4 Testing Methodology

The following points provide an overview of how the operational demonstration and testing for this application was accomplished:

- Energy delivered to and received from the BESS was measured on the high side of the BESS interconnection transformer through the AMI system deployed as part of the project. All data collected were stored in KCP&L's MDM and DMAT systems.
- Energy delivered to and received from the PCS (and battery) was measured in the SMS HMI utilizing the PCS CTs/PTs. All data collected were stored in the SMS HMI.
- BESS discharge for electricity supply capacity was initiated in two ways; 1) the distribution grid operator manually initiated a scheduled "Block Mode" discharge, or 2) the DERM scheduled a DR event for the BESS.
- Multiple discharge events were conducted to evaluate the potential maximum discharge levels that were sustained for 1-, 2-, 3-, and 4-hour discharge events.

3.4.9.2.1.5 Analytical Methodology

The following points provide an overview of the analytical methods that were used to evaluate the impact and benefits of this application:

- AMI 15-minute interval load data for each BESS discharge for this application were extracted from the MDM System through KCP&L's DMAT.
- PCS 10-second interval data were extracted from the SMS HMI for each discharge event.
- Multiple discharge events were analyzed to verify the potential maximum discharge levels that were sustained for 1-, 2-, 3-, and 4-hour discharge events.
- Historical hourly system energy production load profile data were analyzed to determine the optimum block discharge level and duration to maximize the BESS capacity reduction.
- Due to other project operational testing requirements, it was not possible to initiate a battery discharge event at system peak; instead, the impact was determined for when the BESS would be normally available.

3.4.9.2.2 Plan Execution and Analysis

The following sections provide details regarding the functional tests performed, data collected, and analysis performed for the Electric Supply Capacity operational test.

3.4.9.2.2.1 Block Discharge Operation

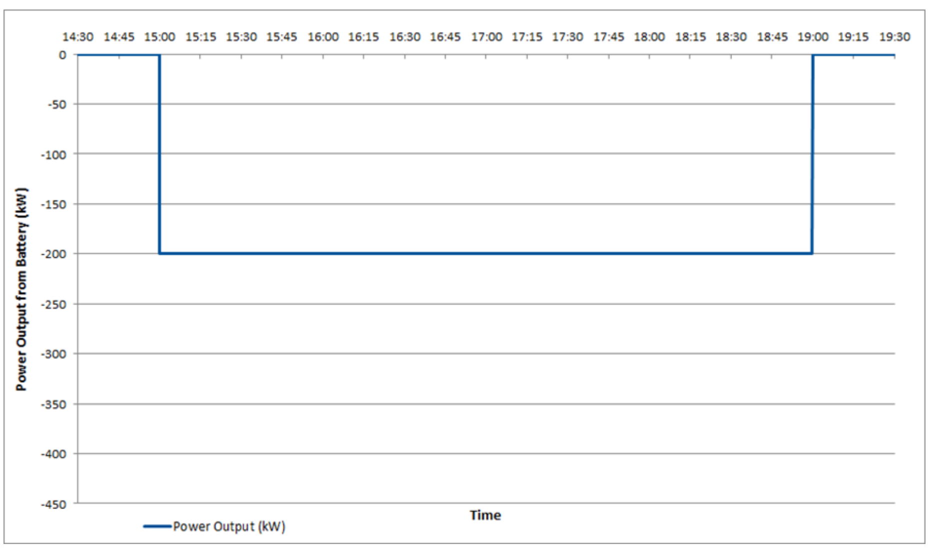
A review of the manufacturer's operation manual identified a recommendation that the battery should not be routinely discharged below a 20% charge level to protect the battery and maintain its life. This operational constraint limits the output of the 1.0-MWh Lithium polymer battery to 800 kWh from a full charge. Additional BESS testing determined the efficiency of the PCS to be 97.6%. Because the net impact to the grid during discharge is measured on the AC side of the PCS, the energy rating of the BESS should be further reduced to factor in the PCS efficiency. The 1.0-MWh battery can only deliver a net impact of 780 kWh (1,000 x 80% x 97.6% = 780) to the grid on a routine basis.

However, since the BESS will only be used for the Electric Supply Capacity function a few hours per year, KCP&L determined that 800 kWh would be a reasonable output for the BESS as measured at the PCS. Any loss of battery life due to this additional draw-down of the battery would be acceptable.

With this operational constraint, the BESS is capable of discharging at 800 kW for 1 hour, 400 kW for 2 hours, 266 kW for 3 hours, and 200 kW for 4 hours. It would require a BESS with rated capacity of 1.0 MW/1.25 MWh to produce 1.0 MW of capacity for 1 hour.

The following figures illustrate these battery discharge cycles. Figure 3-158 shows the ideal output of battery during discharge cycles for 4 hours, and Figure 3-159 shows the ideal output of battery for 2 hours.

Figure 3-158: Ideal Battery Discharge Cycle for 4 Hours



For most of the block discharge operations, the BESS was set to discharge for 4 hours from 3 PM to 7 PM local time. This coincides with the utility's system and residential peak load times and is consistent with the TOU peak-pricing time period. To achieve a full 800-kWh discharge, the following settings were configured in the SMS:

- The PCS Discharge Rate was set to 200 kW to deliver 800 kWh over the 4-hour discharge period.
- The PCS Ramp Rate was set to 20 kW/second. It took 10 seconds to ramp up and discharge at the set power of 200 kW.

- The battery was set to discharge from 2:55 PM to 7:05 PM (with current operational experience these could now be set to 2:59 PM and 7:01 PM) to allow the ramping up and down outside of the discharge period.
- The PCS State of Charge (SOC) threshold was lowered from 20% to 15%. This allowed the battery to discharge beyond the recommended discharge limit to ensure that the battery would achieve the scheduled discharge over the required discharge period.

Figure 3-159: Ideal Battery Discharge Cycle for 2 Hours

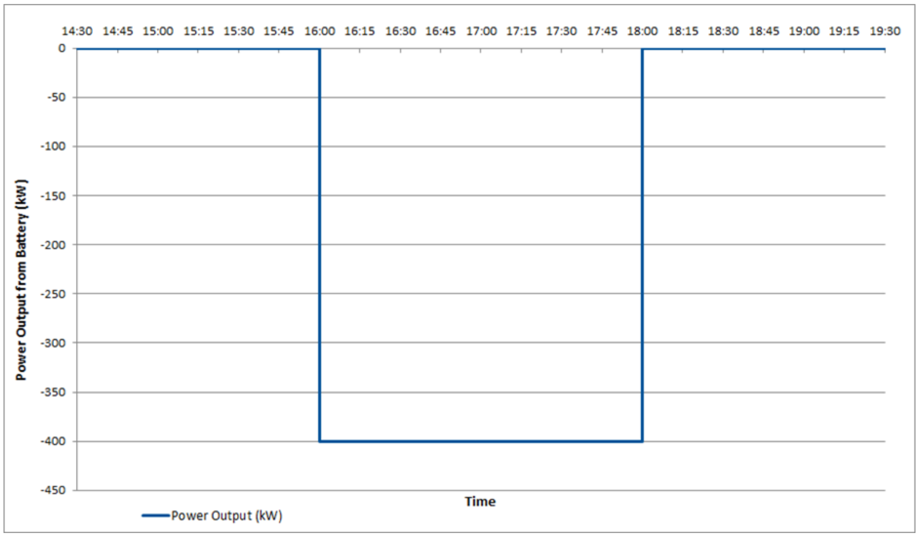
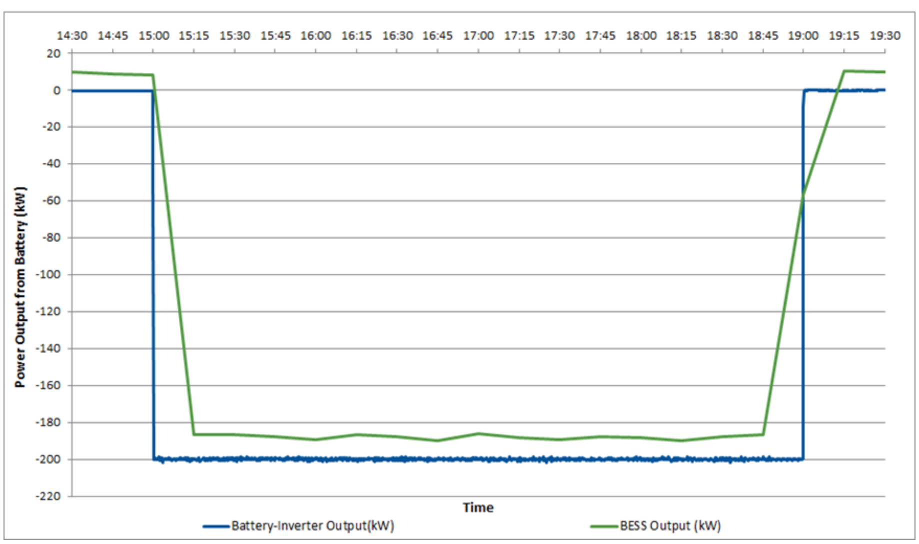


Figure 3-160 shows the battery discharge cycle under these typical settings. The BESS output is measured by the AMI in 15-minute intervals on the primary side of the transformer. The AMI records the net output of the BESS (entire system) which includes the battery, SMS, transformer and the auxiliary loads (air conditioner, lighting, control systems, etc.). The SMS HMI records the AC output of the PCS in 10-second intervals. When the battery is in a discharge cycle, the power delivered to the grid is lower than the set value of 200 kW, as the battery provides the power to the auxiliary loads (which are normally fed from the grid). Hence, during discharge the net grid impact of the BESS is that which is recorded by the PCS.

Figure 3-160: Typical Battery Discharge Cycle for 4 Hours



It is important to understand the relationship of these metering points and their relationship to the auxiliary loads. For capacity credits it is important to control the discharge based on the PCS outputs, as they reflect the impact of the BESS discharge on the grid. The AMI metering records the net energy delivered to and received from the BESS and is used to calculate the overall efficiency of the BESS.

3.4.9.2.2.2 Potential System Peak Load Reduction

The KCP&L project team performed an analysis to identify the potential system peak load reduction that might be realistically achievable with battery energy storage systems. For this analysis, hourly load data of the KCP&L system were collected for 2012 and 2013. Figure 3-161 below shows the hourly annual load profile of the KCP&L system for the year 2012, during which a peak load of 3,642 MW was achieved. In 2013 a similar load profile was produced, but a maximum load of only 3,382 MW was registered. Figure 3-162 shows the daily minimum and maximum loads for 2012 and provides a better visualization of the daily and seasonal load functions.

Figure 3-161: KCP&L 2012 System Hourly Load Profile

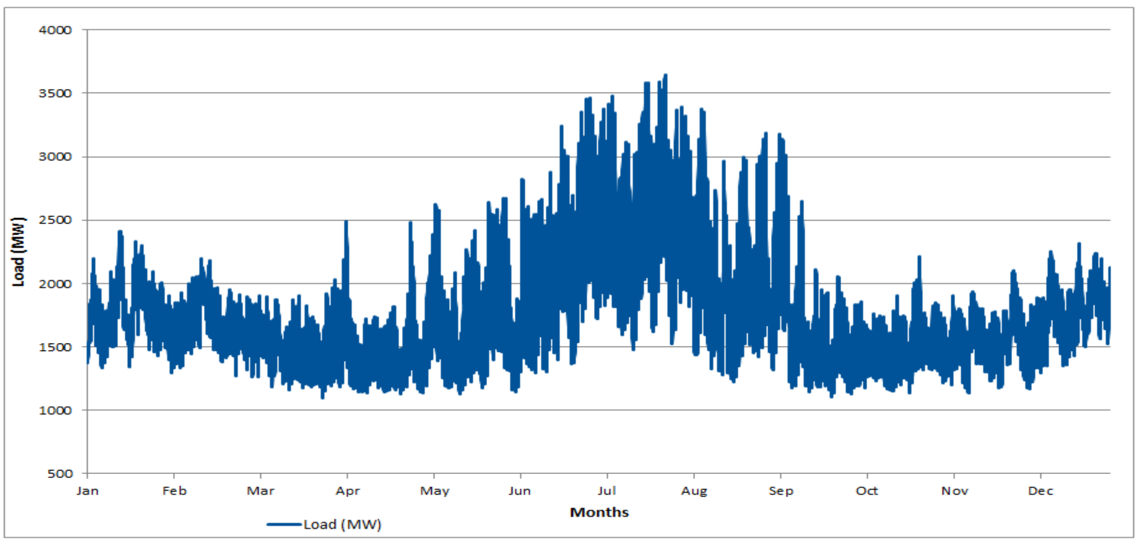


Figure 3-162: 2012 Daily System Minimum and Maximum Loads

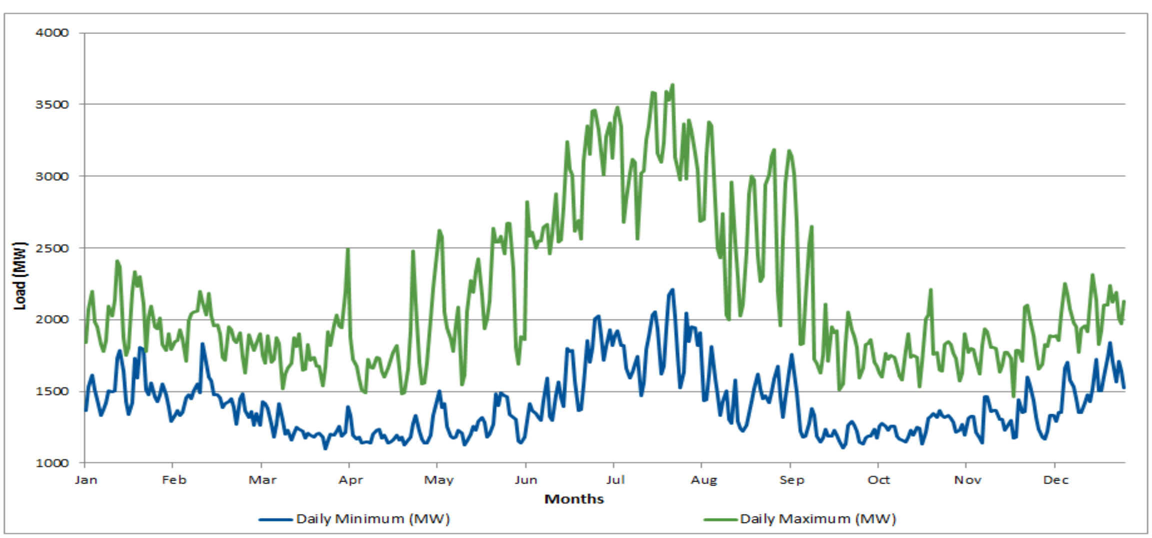


Figure 3-163 shows the annual load duration curves for the KCP&L system for 2012 and 2013. The inset shows a detailed view of the curve for the top 5% of loads. The area under the load-duration curve represents the energy demanded by the system, and the curve illustrates the relationship between energy use and generating capacity needs.

The load-duration curves show that the minimum annual load is about 30% of the peak load, and the inset shows that there are only 25 to 30 hours a year during which the loads exceed 95% of the peak load.

Figure 3-163: System Load Duration Curves

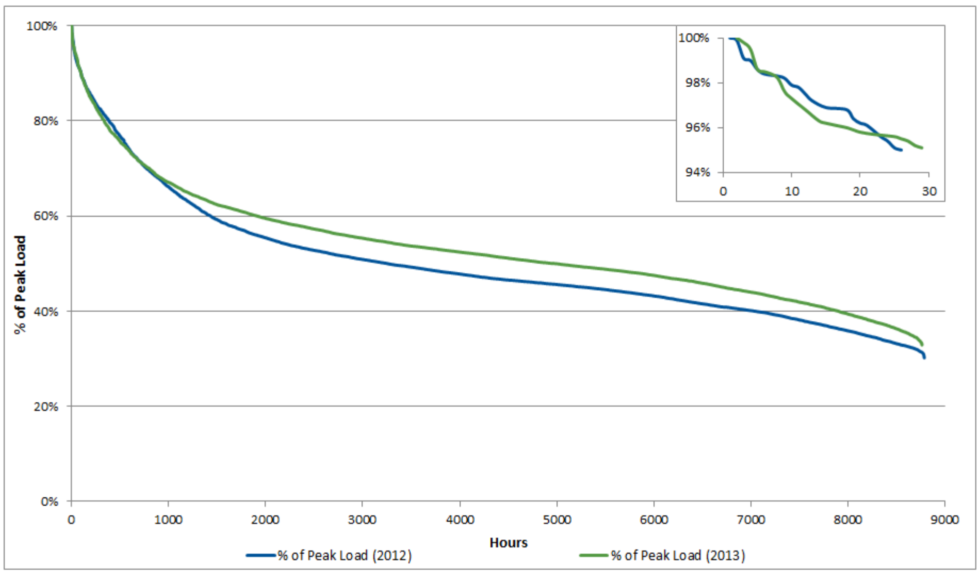


Figure 3-164 plots the number of hours when the load was 95% or higher of peak load. This chat shows that to achieve a 5% capacity reduction, DR or energy storage resources would be required for 25-30 hours annually. Additionally, to achieve a 1.5% capacity reduction these resources would only be required for 5-6 hours annually.

Figure 3-164: Hours with Load Higher than 95% of Peak Load

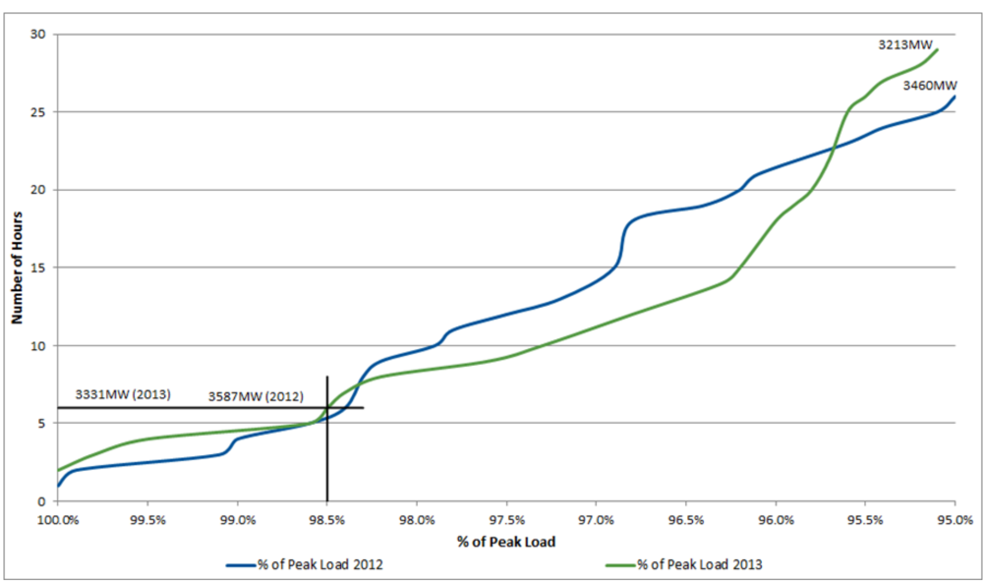


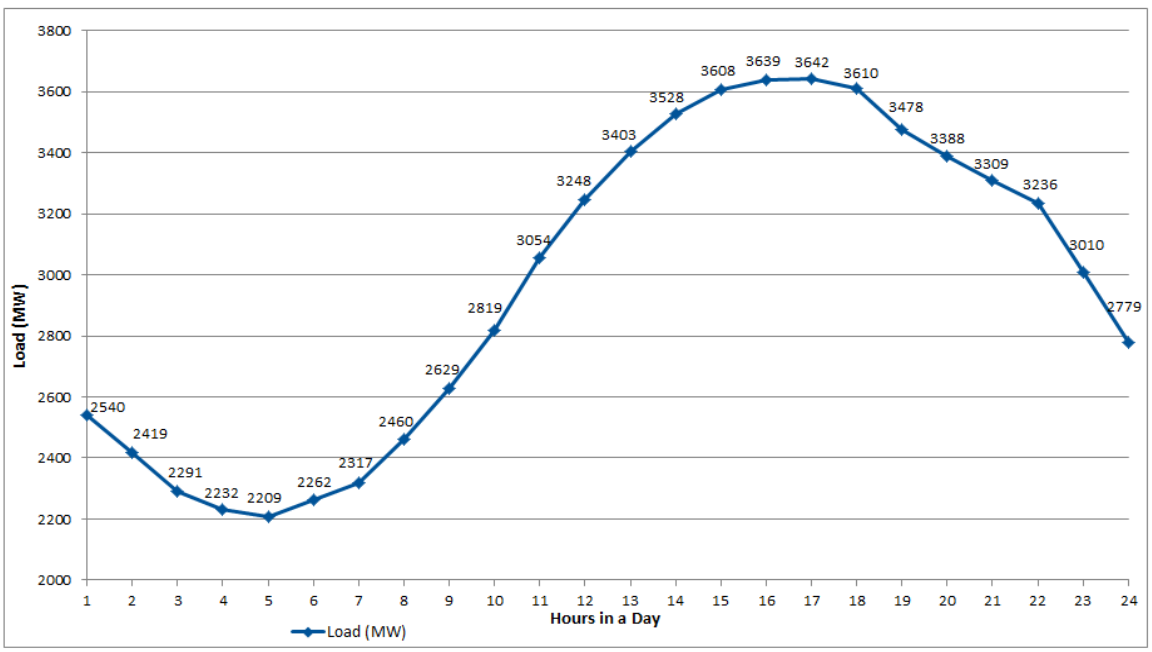
Table 3-114 shows the distribution of top hourly system loads for 2012. The 2012 peak hour of 3,642 MW is highlighted in red. The four additional hourly loads greater than 98.5% of peak (a 55 MW reduction) are highlighted in green and occur over two separate days. The additional hourly loads greater than 95% of the peak (a 182 MW reduction) are highlighted in yellow and occur over seven separate days (nine in 2013). The table also shows that for 1% of peak load reduction (36.4 MW), all of the hours occur on the peak load day and are bounded by the dark border.

Table 3-114: 2012 Top System Hourly Loads

Date\Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
6/27/2012	2169	2028	1904	1834	1798	1843	1915	2081	2245	2443	2669	2850	3032	3187	3328	3411	3456	3441	3375	3260	3144	3062	2849	2605
6/28/2012	2403	2242	2139	2063	2006	2011	2062	2220	2431	2592	2815	3017	3160	3267	3374	3441	3461	3446	3388	3252	3168	3093	2859	2602
7/5/2012	2229	2082	1992	1924	1887	1923	1977	2131	2362	2584	2807	3005	3160	3255	3344	3397	3414	3375	3323	3203	3077	3009	2778	2525
7/6/2012	2319	2163	2052	1951	1920	1929	1980	2123	2351	2572	2841	3049	3209	3325	3404	3452	3482	3435	3338	3224	3085	2989	2786	2563
7/7/2012	2360	2205	2059	1970	1895	1842	1818	1936	2167	2445	2705	2945	3095	3186	3249	3301	3342	3333	3281	3092	2968	2891	2699	2492
7/17/2012	2229	2107	1990	1924	1881	1930	2012	2171	2386	2590	2793	2964	3111	3160	3221	3303	3352	3310	3241	3156	3081	3003	2794	2542
7/18/2012	2358	2220	2127	2056	2033	2079	2164	2320	2495	2692	2918	3138	3310	3433	3531	3582	3585	3568	3500	3402	3312	3224	2991	2743
7/19/2012	2560	2415	2246	2108	2056	2108	2195	2311	2480	2700	2898	3083	3224	3348	3453	3541	3579	3551	3467	3357	3210	3098	2866	2600
7/20/2012	2396	2222	2083	1978	1934	1961	2012	2139	2296	2490	2644	2788	2915	3011	3077	3142	3162	3138	3041	2905	2787	2663	2476	2251
7/21/2012	2052	1896	1778	1697	1650	1637	1618	1717	1899	2108	2304	2491	2657	2801	2922	3022	3088	3097	3048	2936	2826	2734	2551	2365
7/22/2012	2169	2005	1896	1793	1733	1707	1676	1728	1926	2160	2431	2649	2841	2967	3081	3154	3208	3237	3224	3140	3015	2939	2718	2510
7/23/2012	2306	2137	2030	1956	1936	1980	2030	2198	2415	2650	2898	3121	3286	3424	3505	3564	3592	3582	3513	3410	3292	3208	2960	2722
7/24/2012	2544	2399	2269	2191	2168	2206	2268	2378	2561	2775	2980	3183	3324	3417	3484	3529	3530	3527	3434	3340	3232	3160	2945	2727
7/25/2012	2540	2419	2291	2232	2209	2262	2317	2460	2629	2819	3054	3248	3403	3528	3608	3639	3642	3610	3478	3388	3309	3236	3010	2779
7/26/2012	2519	2288	2158	2076	2021	2074	2148	2205	2279	2342	2390	2423	2524	2660	2836	3003	3116	3135	3097	2990	2843	2742	2503	2280

Figure 3-165 shows the hourly loads for the 2012 system peak day. The peak load day was determined to be on 7/25/2012, with a peak load of 3,642 MW. This daily load curve will be further analyzed for the battery operation.

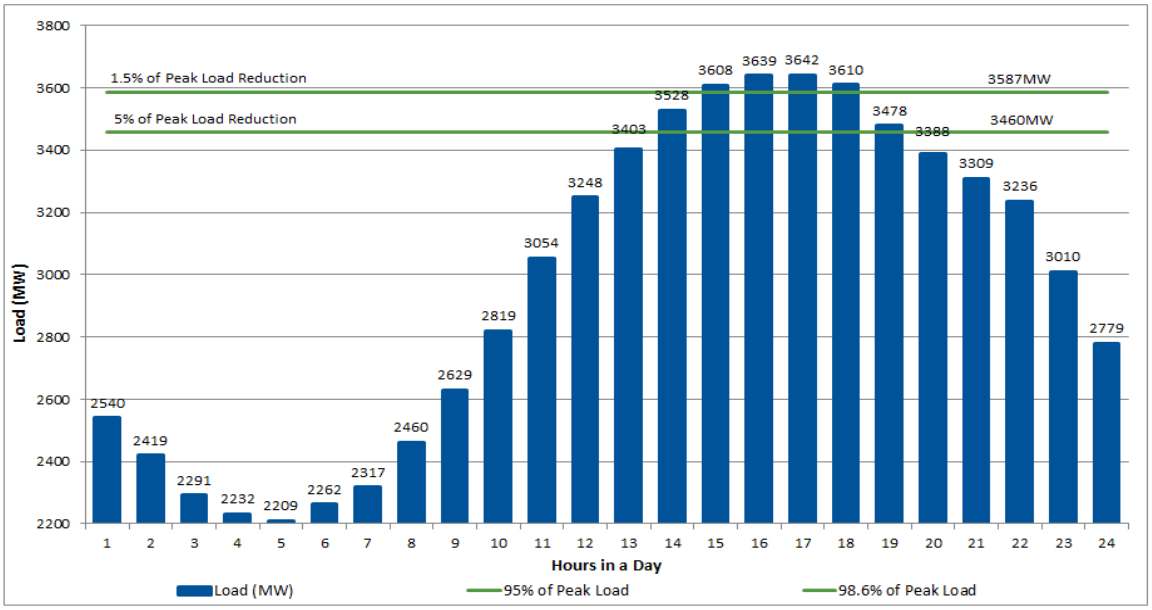
Figure 3-165: Daily Load Curve for 2012 Peak Day



3.4.9.2.2.3 Battery Storage Requirements to Achieve Peak Load Reduction

The KCP&L project team performed an analysis to identify the energy storage requirements needed to achieve the potential system peak load reductions presented in the previous section. Based on the historical load data, year 2012 had the highest peak load of 3,642 MW. A 5% load reduction would limit the peak load to 3,460 MW, while a 1.5% load reduction would limit the peak load to 3,587 MW. Figure 3-166 illustrates these potential reductions.

Figure 3-166: Load Curve for Peak Load Day for 2012



An iterative analysis of the 2012 annual hourly load data was performed to determine the BESS-stored energy requirement to achieve various levels of peak load reduction. Table 3-115 provides a compilation of this analysis and shows the BESS requirements to achieve up to 5% peak load reduction.

Table 3-115: Inverter Rating versus Storage Capacity

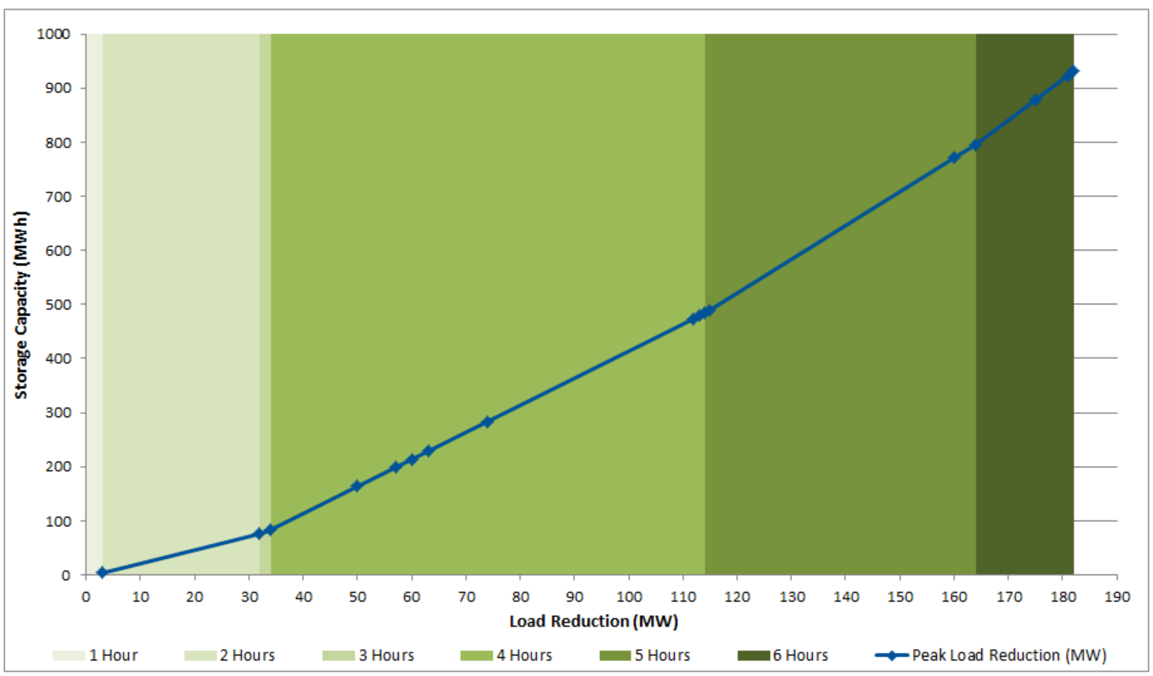
Peak Load = 3,642 MW							
Hourly Load (MW)	% of Peak Load	Peak Day Hours of Operation	Days of Operation	Peak Day Energy Req. (MWh)	Peak Load Reduction (MW)	Storage Capacity (MWh	Ratio
3639	0.08	1	1	3	3	3.75	1.25
3610	0.88	2	1	61	32	76.25	2.38
3608	0.93	3	1	67	34	83.75	2.46
3592	1.37	4	1	131	50	163.75	3.28
3585	1.57	4	2	159	57	198.75	3.49
3582	1.65	4	3	171	60	213.75	3.56
3579	1.73	4	3	183	63	228.75	3.63
3568	2.03	4	4	227	74	283.75	3.83
3530	3.08	4	4	379	112	473.75	4.23
3529	3.10	4	5	383	113	478.75	4.24
3528	3.13	4	5	387	114	483.75	4.24
3527	3.16	5	5	392	115	490.00	4.26
3482	4.39	5	5	617	160	771.25	4.82
3478	4.50	5	6	637	164	796.25	4.86
3467	4.81	6	6	703	175	878.75	5.02
3461	4.97	6	6	739	181	923.75	5.10
3460	5.00	6	7	745	182	931.25	5.12

For select system load levels up to a 5% peak load reduction, the table shows the Peak Day Energy required to limit the system load to the reduced load level indicated. It also lists the number of Peak Day Hours the BESS would be operated and the Days of Operation that the BESS would be needed to maintain the reduced system load level. The Storage Capacity column factors in the 80% manufacturer derating and provides the battery capacity required to deliver the Peak Day Energy (MWh) required. The Ratio column computes the optimum MWh/MW ratio for the fleet of BESS resources to achieve the indicated peak load reduction. This table shows that to act as a resource for Electric Supply Capacity, the BESS assets should be configured with between 2.5 MWh and 5.0 MWh of storage capacity for each MW of inverter capacity.

The table also shows that the BESS resources, when operated for capacity reduction, on a single day annually could achieve up to a 1% reduction in system peak. When operated in this manner two days annually, a 1.5% reduction in system peak could be achieved, and so on: a reduction of 1.75% for three days, 3% for four days, and 4.5% for five days. To achieve a 5% reduction in system peak demand, the BESS resources would need to operate over seven days (nine days for 2013 load data). Based on this analysis, the BESS resources could be operated for other grid purposes and benefits over 355 days of the year.

Figure 3-167 is a graph of Table 3-115 data showing the BESS storage capacity required to achieve various levels of peak load reduction. The shaded areas of the plot illustrate the number of peak day hours that the BESS would need to operate. The figure shows that to achieve a reduction in peak demand of 1% to 5% there would be a very linear relationship between the MW demand reduction and the MWh capacity required to achieve the reduction.

Figure 3-167: Inverter Rating vs. Storage Capacity



3.4.9.2.2.4 Issues and Corrective Actions

The following issues and corrective actions were encountered during the performance of the Electric Supply Capacity operational testing and analysis.

Table 3-116: Issues and Corrective Actions

Issue	Corrective Action
• Per manufacturer recommendation, battery should not be routinely discharged below 20% of rating.	• Limited scheduled BESS discharge to 800 kW. • Set minimum threshold to 15% of capacity for discharge events.
• Determined that battery required a minimum ramp rate to smoothly transition to full power discharge.	• Set ramp rate of 20 kW/second. • Adjusted discharge times to allow for ramp up/down.
• Other operational analyses precluded dispatching BESS at system peak.	• Performed the BESS capacity dispatch events as scheduling allowed, but analyzed the impact of event as if it had occurred at peak.

3.4.9.2.3 Findings

The results obtained in the execution and analyses of Electric Supply Capacity operational testing are summarized in the sections below.

3.4.9.2.3.1 Discussion

The 1.0 MW/1.0 MWh grid-connected BESS is only capable of discharging 80% of its rated storage capacity; therefore, the BESS is only capable of reducing peak load by 0.8 MW for 1 hour, 0.4 MW for 2 hours and 0.2 MW for 4 hours. Based on KCP&L's 2012 and 2013 system load profiles, the BESS could have been used for a single hour each year and achieved the full 800-kW peak load reduction.

The highest KCP&L system peak load for 2012 and 2013 was 3,642 MW, recorded in 2012. Analysis of the 2012 system loads found that all of the top 1% of loads occurred over 4 hours on the peak day, making it possible to achieve 36 MW of demand reduction by operating any installed BESS (or other DR assets) on a single day. Analysis showed that 1.5% of the highest loads occurred over 5-6 hours each year but occurred on two separate days. The analysis of the 2012 and 2013 data also showed that the top 5% of system loads occurred for a total of 26-30 hours over seven to nine individual days. To achieve a full 5% (182 MW) demand reduction, BESS and other DR assets would need to be operated seven to nine days for a total of 26-30 hours.

Additional analysis was performed to determine the storage capacity and rating of the BESS resources that would be needed to obtain up to 5% peak load reduction for 2012. Using the hourly load data, the battery storage capacity necessary for providing the required energy to achieve associated demand reduction was calculated. The following table summarizes the BESS capacities that would be required to achieve various levels of demand reduction based on 2012 load data.

Table 3-117: BESS Requirements for Demand Reduction

Demand Reduction (MW)	Percent Reduction (%)	Inverter Capacity (MW)	Storage Capacity (MWh)	Peak Day Hours	Days Operated	MW/MWh Ratio
1		1	1.25	1	1	1.25
3	~.1	3	3.75	1	1	1.25
34	~1	34	84	3	1	2.46
57	~1.5%	57	199	4	2	3.49
112	~3	112	474	4	4	4.23
164	4.5	164	637	5	6	4.86
182	5	182	931	6	7	5.12

To achieve small demand reductions where the BESS is only needed for a 1-hour discharge, the ratio of storage capacity to inverter rating is 1.25 due to the consideration that only 80% of battery capacity can be dischargeable. Similarly, for load reduction of 1% of the peak load, the ratio of storage capacity to inverter rating increased to 2.5 and the storage system needs to operate for 3 hours. For 5% peak load reduction, the ratio significantly increased to 5 and the BESS needs to operate for 6 hours on a peak load day. This analysis shows that when acting as a resource for Electric Supply Capacity, the optimal configuration of BESS assets would be to install between 2.5 MWh and 5.0 MWh of storage capacity for each MW of inverter capacity.

3.4.9.2.3.2 Expectations vs. Actuals

The following table provides a comparison of the Expected Results and the Actual Outcomes for the Electric Supply Capacity operational test.

Table 3-118: Expected Results vs. Actual Outcome

Expected Results	Actual Outcome
• Demonstrate controlled operation of battery at time of system peak via operator-initiated events and DERM-initiated DR events.	• The BESS was used to reduce the peak load by: – Discharging at a fixed rate by the operator – Discharging in response to DERM Demand Response events.
• Determination of the effective MW peak reduction for a 1-MWh battery.	• Identified that the manufacturer recommendation that the battery charge level should not fall below 20% of rating, to prevent battery damage or significantly reduce battery life. Successfully discharged full 800 kWh (80% of capacity) over 1-, 2-, and 4-hour events.

3.4.9.2.3.3 Computational Tool Factors

The following table lists the values derived from the Electric Supply Capacity operational test analysis that will be used as inputs to the SmartGrid Computational Tool and the Energy Storage Computational Tool.

Table 3-119: Computational Tool Values

Name	Description	Calculated Value
Energy Storage Use at Annual Peak Time (MW)	The size of the generation investment deferred as a result of installing energy storage.	0.8 MW
Generation Capacity Deferred (MW) (ESCT)	The size of the generation investment deferred as a result of installing energy storage.	0.8 MW

3.4.9.2.4 Lessons Learned

Throughout the conduct of the operational testing and analysis of the BESS for Electricity Supply Capacity function, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- The manufacturer's recommendation – that the battery should not be routinely discharged below a 20% charge level, to protect the battery and maintain its life – must be factored in when sizing the battery storage component for any BESS.
- For BESS resources operated for Electric Supply Capacity, the optimal economic configuration of BESS assets is to install between 2.5 MWh and 5.0 MWh of storage capacity for each MW of inverter capacity.
- BESS and other DR resources may need to operate for up to 6 hours daily for aggressive (above 5%) demand reduction targets and require some BESS assets to have 6.0 MWh of storage capacity for each MW of inverter capacity. While the current KCP&L daily system load profile indicates that longer operation would be required to achieve these increased levels of load reduction, it is believed that solar and other DG and DR programs could modify the daily system load shape to a point where significant load reduction could be achieved within a 6-hour peak load period.

3.4.9.3 T&D Upgrade Deferral

Transmission and Distribution (T&D) Upgrade Deferral application involves installing Energy Storage in order to delay transmission and/or distribution system upgrades. The value of this application is derived from the fact that storage can be used to provide enough incremental capacity to defer the need for a large "lump" investment in T&D equipment. If using an energy storage device to defer a T&D investment, proper consideration must be given to reliability. T&D capital investments must maintain the extremely high reliability of the electric delivery system. Therefore, any energy storage solution that defers the need for a T&D investment must similarly maintain the reliability of the system. For energy storage deployments this means ensuring that the storage solution has enough redundancy or modularity such that the effective reliability of the solution is adequate.

3.4.9.3.1 Overview

The following sections provide an overview of the operational, demonstration, testing, and evaluation methodology used for the T&D Upgrade Deferral operational test.

3.4.9.3.1.1 Description

A 1.0-MW-/1.0-MWh-capable grid-connected Battery Energy Storage System has been installed adjacent to the Midtown Substation, with direct interconnect to a single 13.2-kV circuit. The grid interconnection and internal component connections of the BESS are illustrated in Figure 3-147 and described earlier in the Electric Time Shift Operational Test section. DMS-based control functions have been implemented for load-following discharge of the battery to demonstrate and evaluate the operational benefit of using the BESS for electric T&D Upgrade Deferral applications. The operator can select from the following grid-level targets for the load-following function:

- Station Power Transformer
- Distribution Substation Bus
- Distribution Circuit

3.4.9.3.1.2 Expected Results

The operational demonstration of the grid connected battery in this application was expected to yield the following:

- Demonstrate load following discharge of battery based on real-time transformer, bus, and circuit loadings.
- Using several representative company distribution circuit load profiles, determination of a representative distribution circuit peak reduction (kW) that can be achieved for a 1.0-MWh battery.

3.4.9.3.1.3 Benefit Analysis Method/Factors

The SGCT and ESCT identified the following benefits derived from energy storage systems ability to offset Transmission and Distribution Upgrade Deferral.

Figure 3-168: Benefits of Transmission and Distribution Upgrade Deferral

				Utility/Ratepayer						Societal			
Location	Market	Owner	Application	Optimized Generator Operation	Deferred Generation Capacity Investments	Deferred Transmission Investments	Deferred Distribution Investments	Reduced Electricity Losses	Reduced Electricity Cost	Reduced CO2 Emissions	Reduced SOx Emissions	Reduced NOx Emissions	Reduced PM Emissions
Distribution	Regulated	Utility	Transmission & Distribution (T&D) Upgrade Deferral	AB	AB		PB	AB		AB	AB	AB	AB

Note: Primary benefits (PB) are quantified in this section. Secondary benefits (SB) and additional benefits (AB) will be addressed in later sections.

The DOE SGCT was used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits were quantified.

- Deferred Distribution Capacity Investments

Benefits were calculated using SGCT formulas. The following factors were measured, projected or calculated during the application operation and/or demonstration.

Deferred Distribution Capacity Investments

- Distribution Feeder Load Reduction (MW)
- Capital Carrying Charge of Distribution Upgrade ($/yr)

Additionally, the DOE ESCT was used to perform the benefit analysis for a utility owned GES system. The following Stationary Energy Storage applications were combined in this analysis.

- Primary Application – Electric Energy Time Shift
- Secondary Application – Electric Supply Capacity
- Secondary Application – T&D Upgrade Deferral

ESCT Primary Benefit for Electric Energy Time Shift:

- Deferred Distribution Investments (Utility/Ratepayers)

3.4.9.3.1.4 Testing Methodology

The following points provide an overview of how the operational demonstration and testing for this application was accomplished:

- Energy delivered to and received from the BESS was measured on the high side of the BESS interconnection transformer through the AMI system deployed as part of the project. All AMI data collected were stored in KCP&L's MDM and DMAT systems.
- BESS discharge for T&D Upgrade Deferral was initiated in by the distribution grid operator. The operator was able to manually set BESS to Load Following Mode in the DMS. The operator would select both the load point (station transformer, bus, or circuit) on the grid to follow, and the maximum load level to maintain.
- Multiple load following discharge events were conducted to evaluate the potential distribution load reduction that could be achieved under various heavy load conditions.

3.4.9.3.1.5 Analytical Methodology

The following points provide an overview of the analytical methods that were used to evaluate the impact and benefits of this application:

- AMI interval load data for each BESS discharge for this application were extracted from the MDM System through KCP&L's DMAT.
- Multiple load following discharge events were analyzed to evaluate the potential distribution load reduction that can be achieved under various loading conditions.
- Historical load profiles for other KCP&L substations and circuits that are substantially different from the SmartGrid Demonstration Circuits were analyzed to identify typical load profiles for which the BESS would have the greatest potential to defer distribution upgrades.
- The level of discharge for T&D Upgrade deferral that is coincident with annual system peak will be determined.

3.4.9.3.2 Plan Execution and Analysis

The following sections provide details regarding the functional tests performed, data collected, and analysis performed for the T&D Upgrade Deferral operational test.

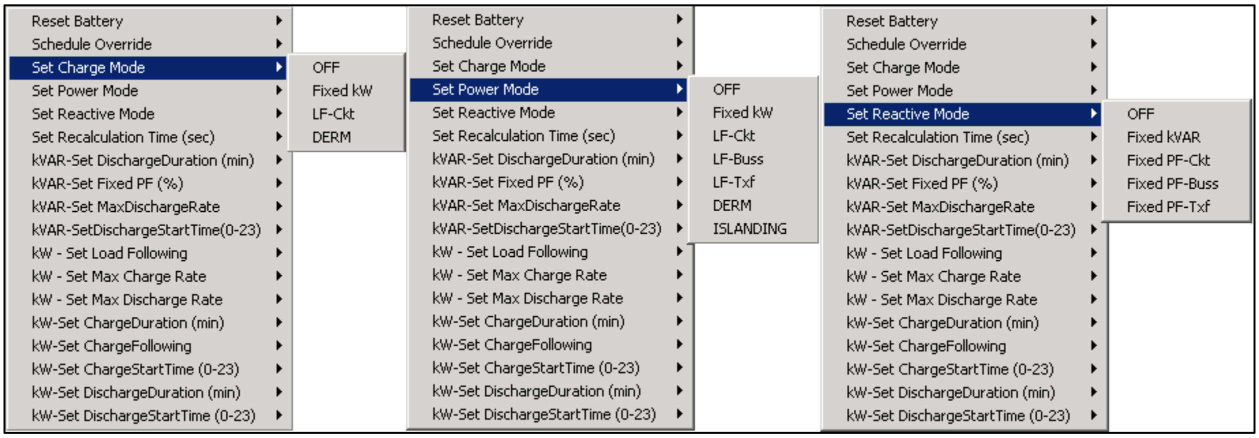
3.4.9.3.2.1 Load Following Operational Demonstration

A review of the manufacturer's operation manual identified a recommendation that the battery should not be routinely discharged below a 20% charge level to protect the battery and maintain its useful life. This operational constrain limits the output of the 1.0-MWh Lithium polymer battery to 800 kWh from a full charge. Additional BESS testing determined the efficiency of the PCS to be 97.6%. Because the net impact to the grid during discharge is measured on the AC side of the PCS, the energy rating of the BESS should be further reduced to factor in the PCS efficiency. The 1.0-MWh battery can only deliver a net impact of 780 kWh (1,000 x 80% x 97.6% = 780) to the grid on a routine basis.

However, since the BESS will only be used for the Transmission and Distribution Upgrade Deferral function a few days per year, KCP&L determined that 800 kWh would be reasonable output for the BESS as measured at the PCS. Any loss of battery life due to this additional draw down of the battery would be acceptable.

The remote operation of the BESS is controlled by the Operating Mode and parameters set by the distribution grid operator in the DMS. Figure 3-169 illustrates selections available to the grid operator to control the operations of the BESS. The BESS can be configured to operate in one of three Load Following Modes: Circuit, Buss, or Transformer.

Figure 3-169: BESS Operating Modes



For the T&D Upgrade Deferral operational demonstration the BESS was operated in Circuit Load Following (LF-Ckt) mode. While in LF-Ckt, the BESS output varies over a period of time to limit the load of the circuit to a specified level. The LF-Ckt mode requires that the following parameters be set by the grid operator.

- Load Following Threshold (kW-Set Load Following) – Maximum circuit load level that the load following algorithm will attempt to maintain
- Max Discharge Rate Allowed (kW-Set MaxDischargeRate) – Maximum rate that the load following algorithm may discharge the battery
- Discharge Start Time (kW-Set DischargeStartTime) – The hour that the BESS load following algorithm may begin discharging to maintain the load following threshold
- Discharge Duration (kW-Set DischargeDuration) – The length of time the load following algorithm

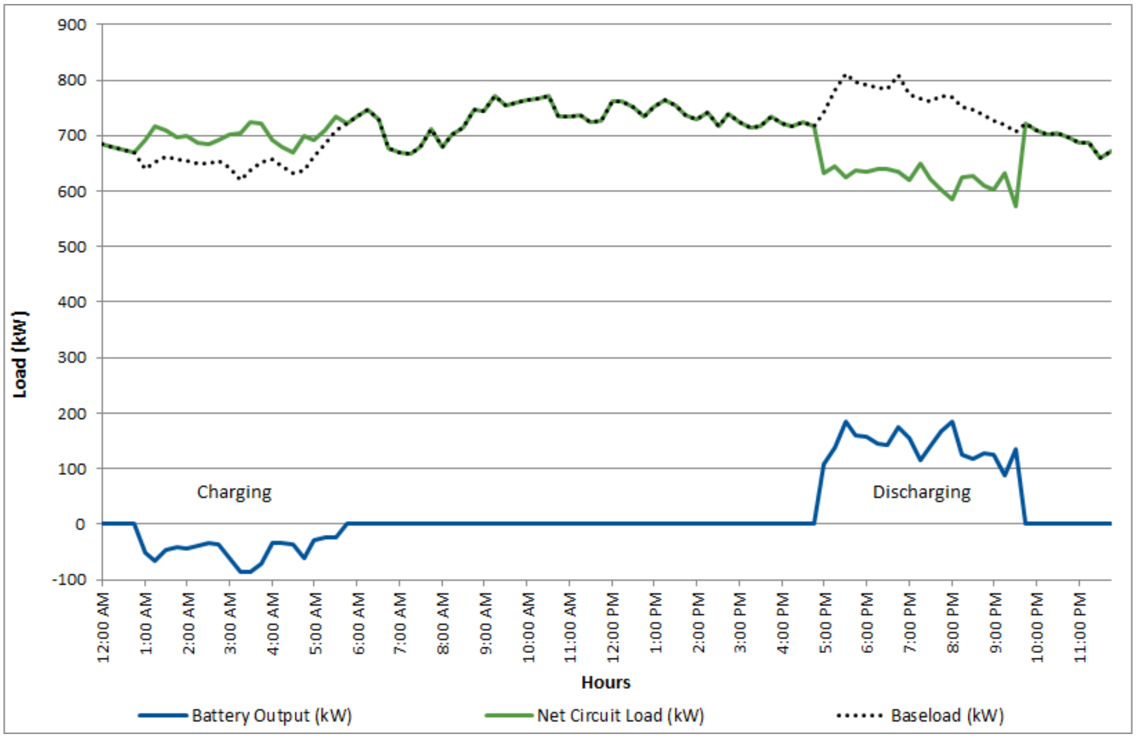
The BESS was installed on Circuit 7564, a lightly loaded radial circuit adjacent to Midtown Substation. The BESS Operating Modes parameters outlined in Table 3-120 were used during the T&D Upgrade Deferral Demonstration.

Table 3-120: BESS Operating Mode Parameters During Load Following Demonstration

	Parameter	Setting
Charge	Charge Mode	Load Following (LF-Ckt)
	Charge Start Time	1:00AM (1)
	Charge Duration	5 hours (300 minutes)
	Max. Charge Rate Allowed	200kW
	Charge Following Threshold	700kW
Discharge	Discharge Mode	Load Following – Circuit (LF-Ckt)
	Discharge Start Time	5:00PM (17)
	Discharge Duration	5 hours (300 minutes)
	Max. Discharge Rate Allowed	200kW
	Load Following Threshold	650kW

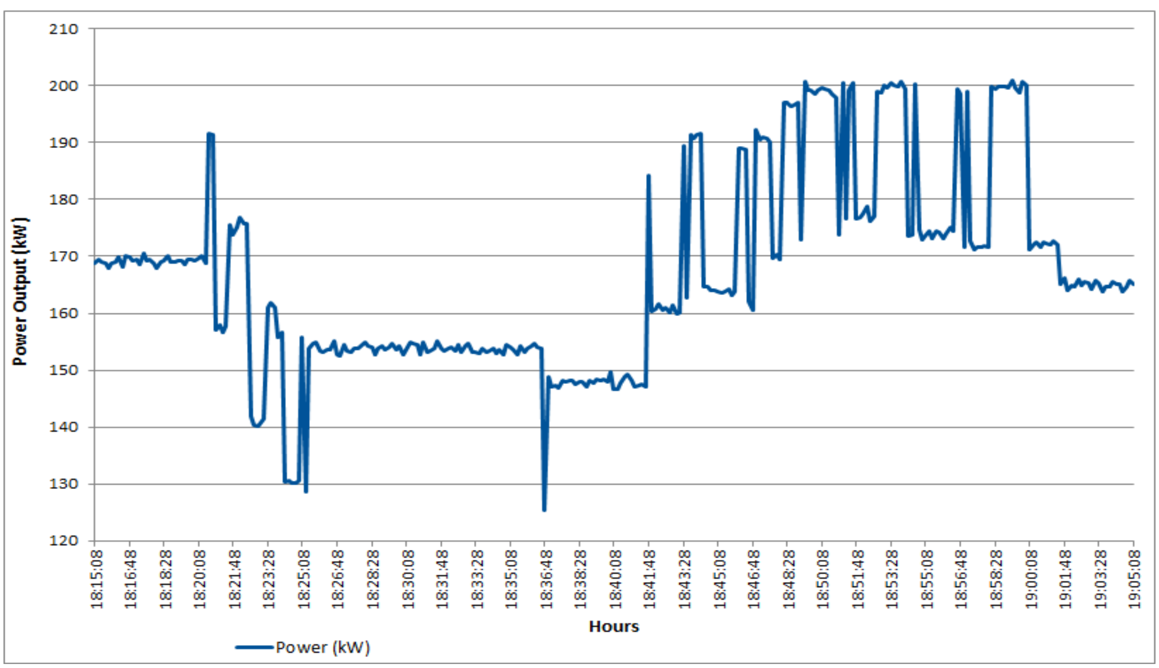
The battery charges and discharges up to 800 kWh energy to moderate the feeder load based on the operating parameters. Figure 3-170 (which illustrates the results of a field demonstration of the BESS in LF-Ckt mode) shows the net impact in the circuit as measured by the AMI 15-minute interval data, from the BESS load following algorithm. While not as tight as expected, the figure shows that the load following algorithm generally maintained the circuit load at the desired level.

Figure 3-170: BESS Load Following Impact – Circuit 7564



Because the BESS Storage Management System (SMS) did not provide a load following function, the project team implemented a rudimentary load following algorithm in a local controller. While the local controller could rapidly alter the SMS outputs, the wide fluctuations in local load in conjunction with the relay deadband settings (Figure 3-171, below) made it virtually impossible for the local controller to precisely maintain the circuit loading at the desired load following threshold setting.

Figure 3-171: BESS Load Following Discharge

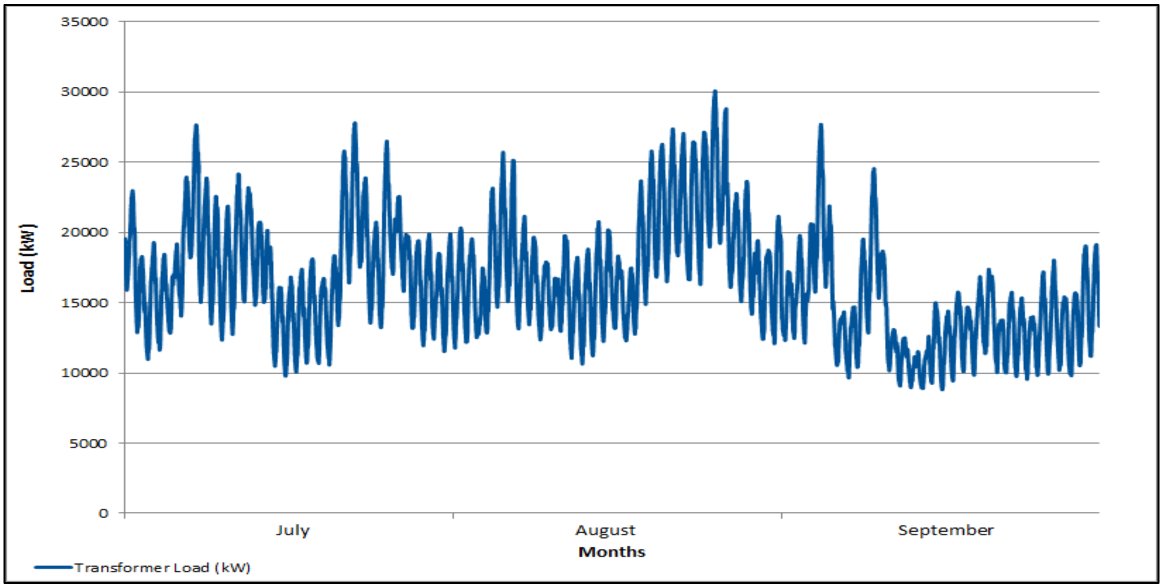


3.4.9.3.2.2 Baseline Load Data for T&D Capacity Analysis

To determine the potential of a BESS to provide T&D capacity reductions, the project team selected a representative substation transformer, residential circuit, and commercial circuit on which to perform the analysis.

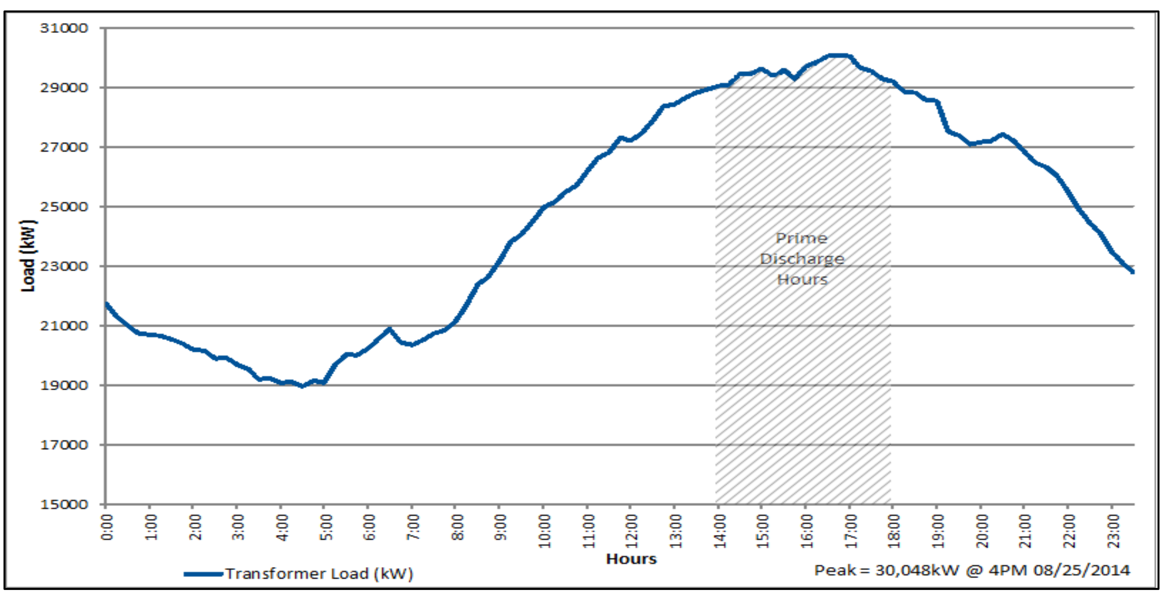
Hourly data for the SmartGrid substation transformer 5-6 was captured and recorded in the DMS HIS. Figure 3-172 below shows the hourly load profile for the last quarter of the operational testing period (July-Sept 2014) for the substation transformer serving eight (8) circuits on busses 5 and 6.

Figure 3-172: 2013 Hourly Load Profile Transformer 5-6



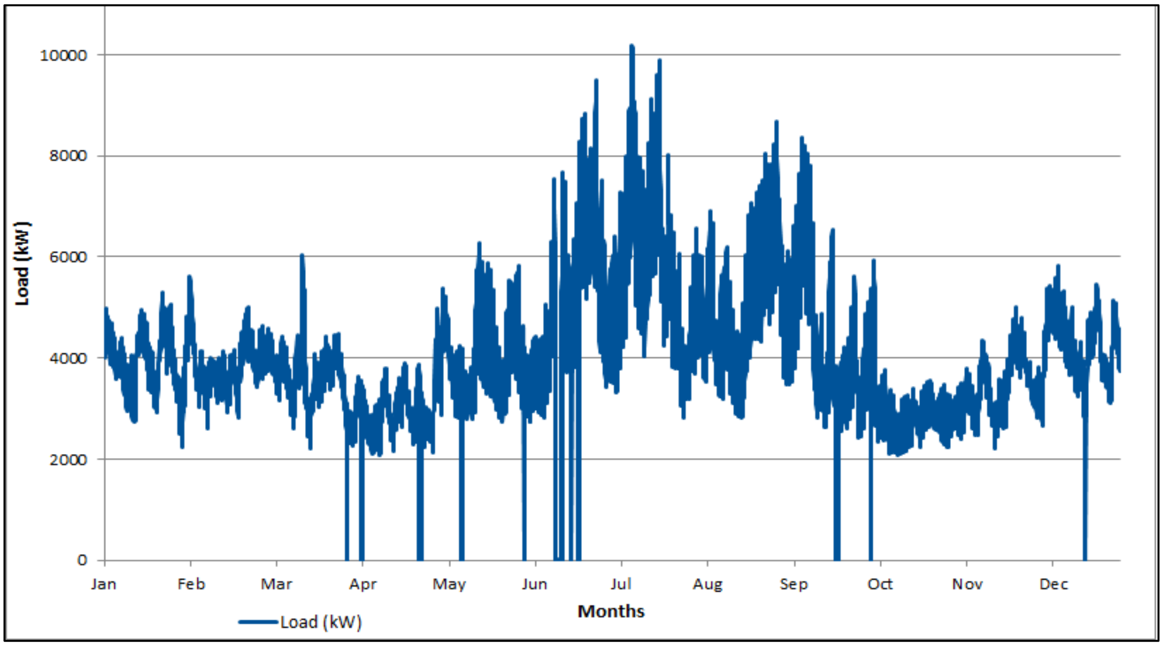
For transformer 5-6 the peak under normal load conditions was 5,315 kW and occurred, coincident with the KCP&L system annual peak, at 5:00 PM on August 25, 2014. Figure 3-173 below shows the 15-minute load profile of the substation transformer for this day. This daily load curve was further analyzed for this function.

Figure 3-173: 2013 Peak Normal Day Load Profile Transformer 5-6



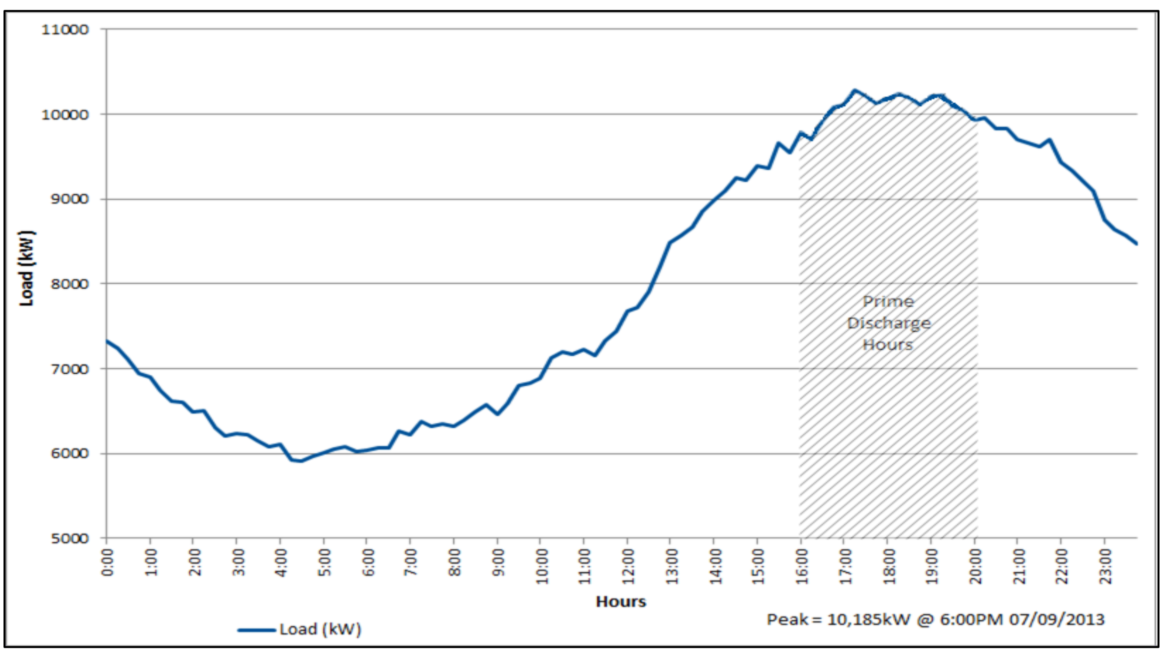
Hourly load data for SmartGrid feeders were captured and recorded in the DMAT. Figure 3-174 below shows the hourly annual load profile during 2013 for SmartGrid Circuit 7571, a predominately residential feeder.

Figure 3-174: 2013 Annual Load Profile Circuit 7571



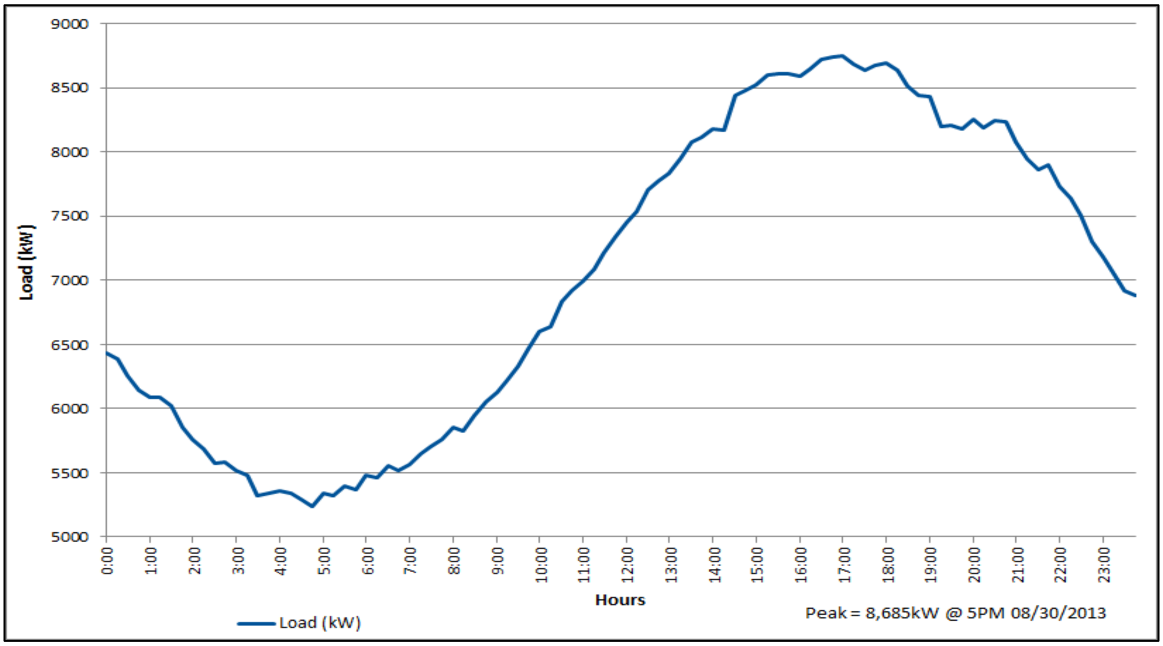
For circuit 7571 the peak load of 10,185 kW occurred at 6:00 PM on July 9, 2013, due to a contingency switching condition. Figure 3-175 below shows the 15-minute load profile of the circuit for this day. This daily load curve was further analyzed for this function.

Figure 3-175: 2013 Peak Day Load Profile Circuit 7571



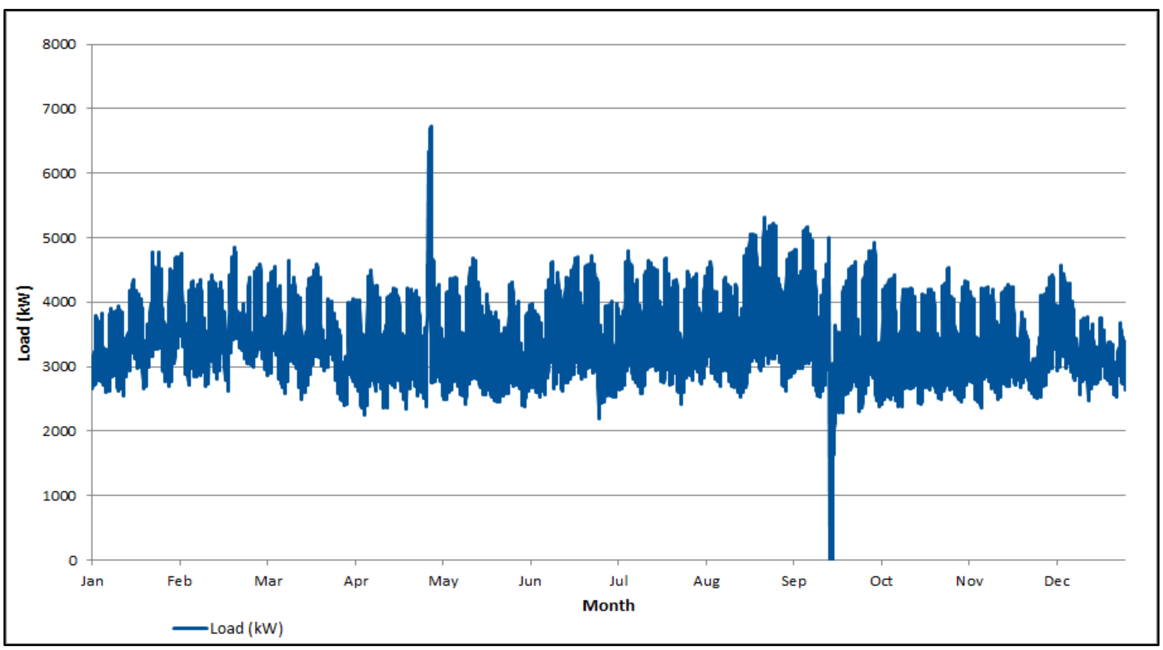
For circuit 7571 the circuit peak under normal load conditions was 8,685 kW and occurred at 5:00 PM on August 30, 2013. Figure 3-176 below shows the 15-minute load profile for the circuit for this day. This daily load curve was further analyzed for this function.

Figure 3-176: 2013 Peak Normal Day Load Profile Circuit 7571



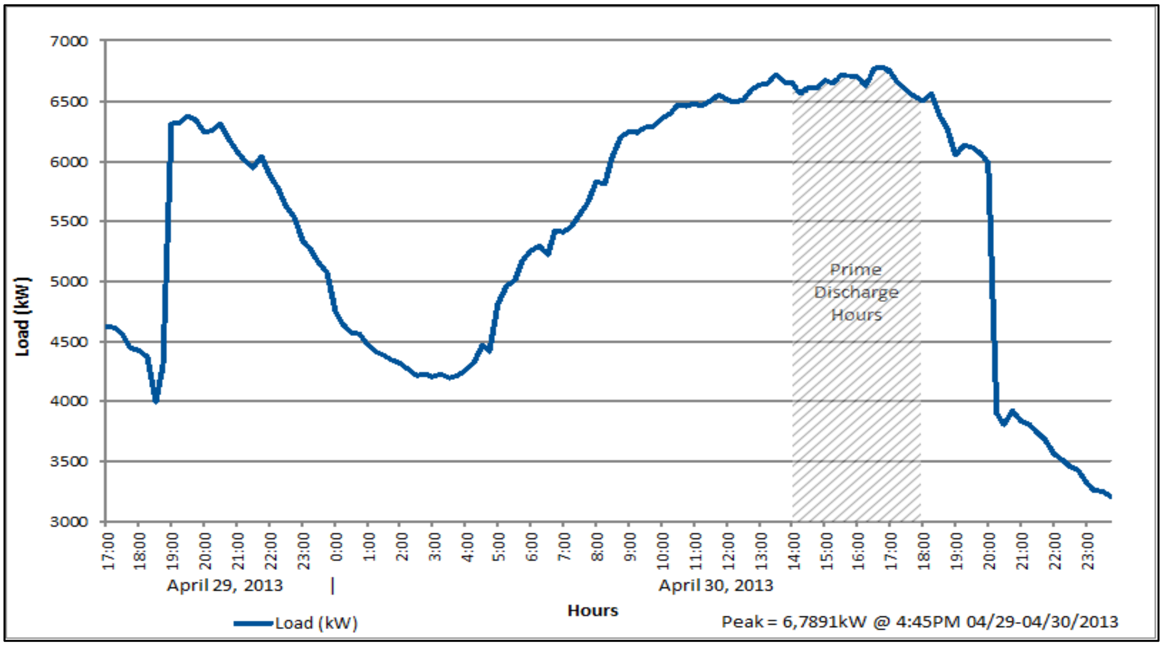
Similarly, hourly data for a SmartGrid commercial feeder was captured and recorded in the DMAT. Figure 3-177 below shows the hourly annual load profile for the year 2013 for SmartGrid Circuit 7514, a predominately commercial feeder.

Figure 3-177: Annual Load Profile Circuit 7514



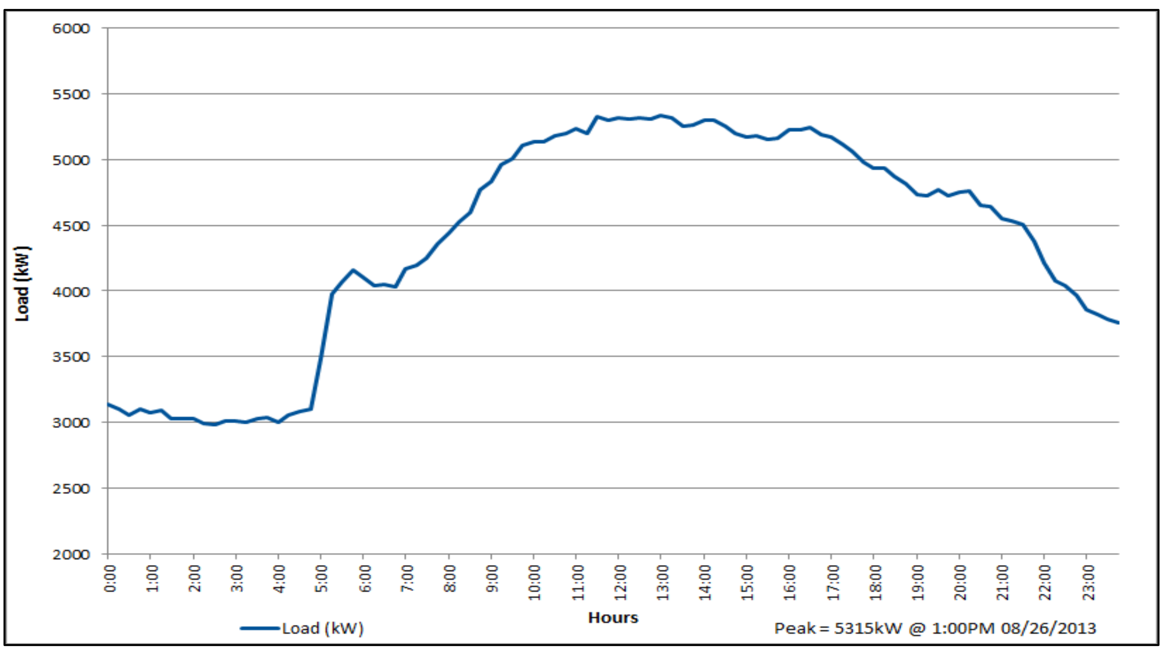
For circuit 7514 the peak load of 6.789 kW occurred at 4:45 PM on April 30, 2013 due to a contingency switching condition. Figure 3-178 below shows the 15-minute load profile for the day of the circuit peak. This daily load curve was further analyzed for this function.

Figure 3-178: 2013 Peak Day Load Profile Circuit 7514



For circuit 7514 the circuit peak under normal load conditions was 5,315 kW and occurred at 1:00 PM on August 26, 2013. Figure 3-179 below shows the 15-minute load profile of the circuit for this day. This daily load curve was further analyzed for this function.

Figure 3-179: 2013 Peak Normal Day Load Profile Circuit 7514



3.4.9.3.2.3 Potential Feeder Peak Load Reduction

The project team performed an analysis to identify the potential transformer and circuit peak load reduction that may be realistically achievable with battery energy storage systems. For this analysis, hourly load data, presented in the previous section, was analyzed. Figure 3-180 below shows the hourly annual load profile for the two circuits under normal and contingency switching conditions.

Figure 3-180: Feeder Load Duration Curve

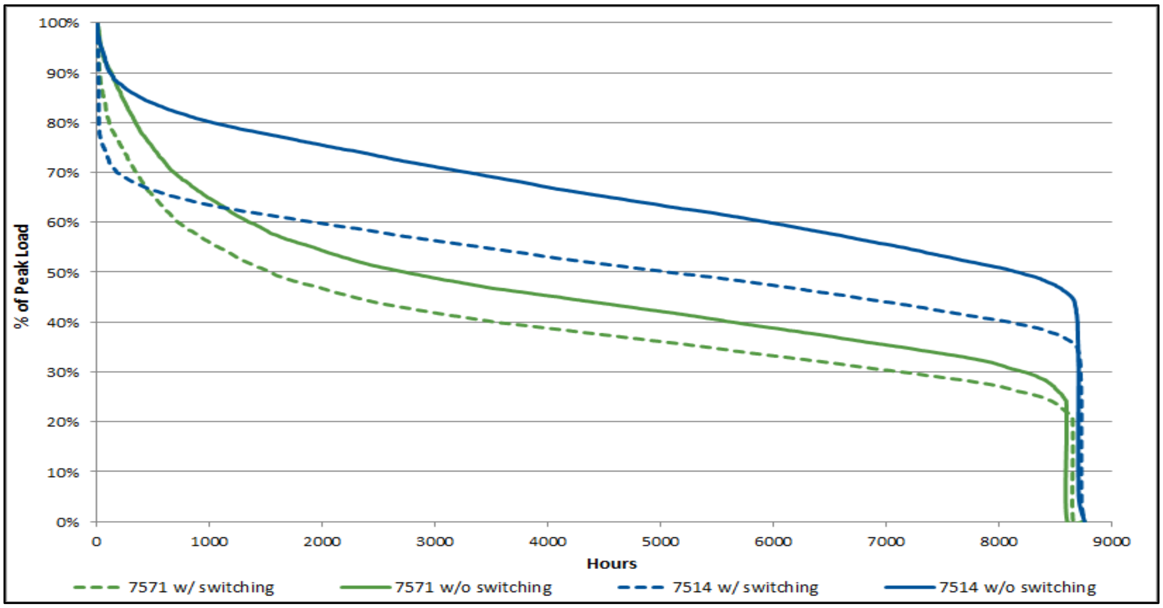
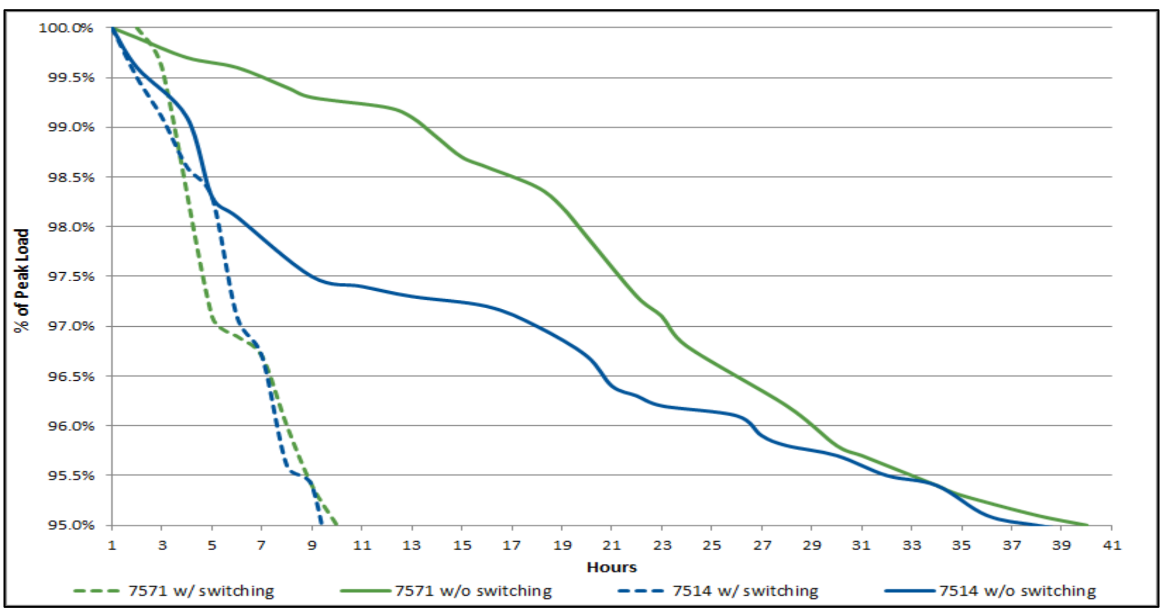


Figure 3-181 plots the number of hours when the load was 95% of peak load or higher. This chart shows that to achieve a capacity reduction of 5% under normal load condition, DR or energy storage resources would be required 40 hours annually. But, since most circuit peak loads occur during contingency switching conditions, a capacity reduction of 5%would only require the use of DR and energy storage resources 10 hours annually.

Figure 3-181: Hours with Load Higher than 95% of Peak Load



The project team performed an analysis to determine the number of hours and days a BESS would be required in order to achieve various levels of load reduction on the substation transformer and circuits being studied. Each table shows Peak Day Hours the BESS would be operated along with the Days and Total Hours of Operation that the BESS would be needed to maintain the reduced system load level. The Prime Hours of Operation column shows the number of total hours that fall within the 4-hour, prime-operation windows illustrated in the peak day load profile figures.

Table 3-121 below show the results of the analysis for substation transformer. This analysis shows that a BESS with a 1.5-MW discharge capacity could achieve a peak load reduction of approximately 5% and would have needed to operate on two days and would have discharged for 6 hours on the peak day.

Table 3-121: Transformer Peak Load Reduction Potential – Transformer 5-6

Peak Day Time	Peak Load (kW)	Max. LF. Discharge (kW)	Peak Reduction (%)	Peak Day Hours of Operation	Days of Battery Operation	Total Hours of Operation	Prime Hours of Operation	Prime Operations (%)
8/25 5:00 PM	29,928	250	0.84%	1	1	1	1	100.0%
		500	1.67%	3	1	3	3	100.0%
		750	2.51%	4	1	4	4	100.0%
		1,000	3.34%	4	1	4	4	100.0%
		1,250	4.18%	6	1	6	4	66.7%
		1,500	5.01%	6	2	7	5	71.4%
		1,750	5.85%	6	2	9	7	77.8%
		2,000	6.68%	6	2	9	7	77.8%
		3,000	10.02%	9	6	26	20	76.9%
		4,000	13.37%	11	11	57	39	68.4%

Table 3-122 below shows the results of the analysis of the residential circuit under contingency switching conditions. This analysis shows that a BESS with 500-kW discharge capacity could achieve approximately a 5% peak load reduction and would have needed to operate on two days and would have discharged for 5 hours on the peak day. Similarity, a BESS with a 1.0-MW discharge capacity could have achieved approximately a 10% peak load reduction, but it would have been required to discharge over 8 hours on the peak day.

Table 3-122: Feeder Peak Load Reduction Potential – Circuit 7571

Peak Day Time	Peak Load (kW)	Max. LF. Discharge (kW)	Peak Reduction (%)	Peak Day Hours of Operation	Days of Battery Operation	Total Hours of Operation	Prime Hours of Operation	Prime Operations (%)
7/9 5:00 PM	10,185	125	1.23%	3	1	3	3	100.0%
		250	2.45%	3	1	3	3	100.0%
		500	4.91%	5	2	9	8	88.9%
		750	7.36%	7	4	16	12	75.0%
		1,000	9.82%	8	4	23	16	69.6%
		1,250	12.27%	9	7	35	22	62.9%
		1,500	14.73%	9	11	57	36	63.2%
		1,750	17.18%	11	11	78	41	52.6%
		2,000	19.64%	11	16	103	55	53.4%

Table 3-123 below shows the results of the analysis of the commercial circuit under contingency switching conditions. This analysis shows that a BESS with 500-kW discharge capacity could achieve approximately a peak load reduction of 7.5% and would have needed to operate on two days and would have discharged for 10 hours on the peak day. Similarity, a BESS with a 1.0-MW discharge capacity could have achieved peak load reduction of approximately 15%, but it would have been required to discharge over 12 hours on the peak day.

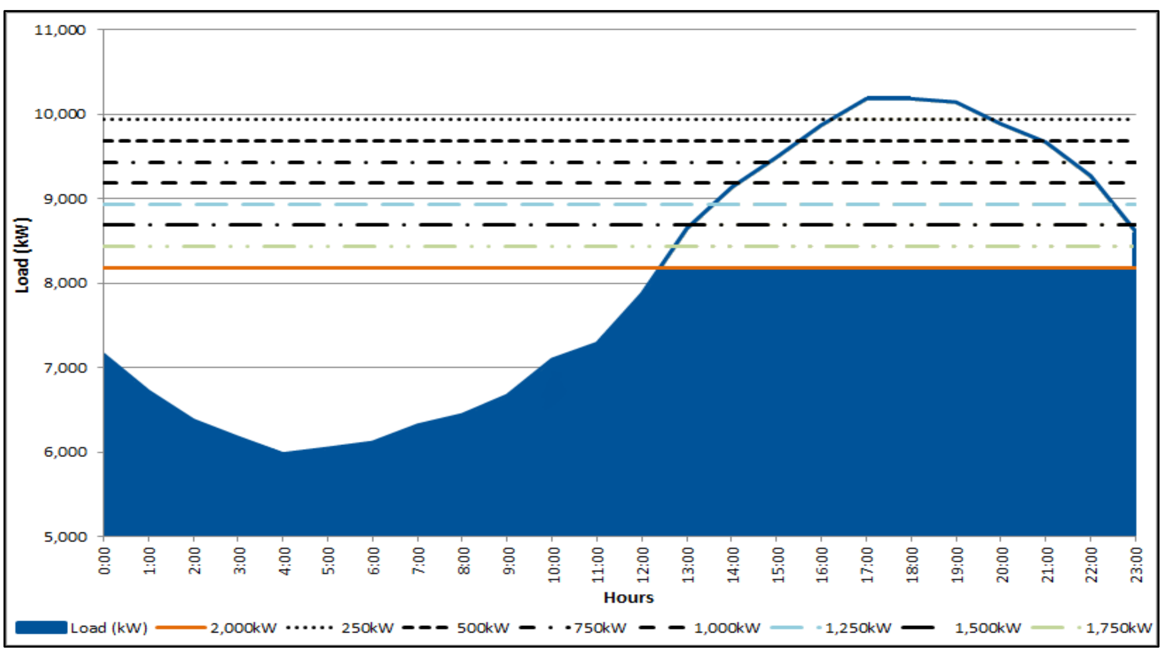
Table 3-123: Feeder Peak Load Reduction Potential – Circuit 7514

Peak Day Time	Peak Load (kW)	Max. LF Discharge (kW)	Peak Reduction (%)	Peak Day Hours of Operation	Days of Battery Operation	Total Hours of Operation	Prime Hours of Operation	Prime Operations (%)
4/30 4:00 PM	6,725	125	1.86%	5	1	5	4	80.0%
		250	3.72%	7	1	7	4	57.1%
		500	7.43%	10	2	12	4	33.3%
		750	11.15%	11	2	14	4	28.6%
		1,000	14.87%	12	2	15	4	26.7%
		1,250	18.59%	13	2	17	4	23.5%
		1,500	22.30%	14	3	22	5	22.7%
		1,750	26.02%	15	14	82	31	37.8%
		2,000	29.74%	15	27	169	67	39.6%

3.4.9.3.2.4 Battery Storage Requirements to Achieve Load Following

The KCP&L project team performed an analysis to identify the energy storage requirements needed to achieve the potential transformer and circuit peak load reductions presented in the previous section. An iterative analysis, illustrated in Figure 3-182, of the hourly load data for the respective peak days was performed to determine the BESS-stored energy requirement to achieve various levels of load reduction. The results of this analysis are presented in the following tables.

Figure 3-182: BESS kWh Required to Achieve Peak Reduction



Each table shows the Peak Day Energy required to limit the system peak load for various levels of load following discharge. Each table also lists the number of Peak Day Hours the BESS would be operated, and the Days of Operation that the BESS would be needed to maintain the reduced system load level. The Battery Capacity column factors in the 80% manufacturer derating and provides the battery capacity required to deliver the Peak Day Energy (MWh) required. The Ratio column shows the optimum MWh/MW ratio for the fleet of BESS resources to achieve the indicated peak load reduction.

Table 3-124 below show the results of the analysis for substation transformer. This analysis shows that a BESS with a 1.5-MW inverter would require a 6.7-MWh battery to achieve the 5% peak load reduction. The table also shows that for this transformer's load profile, a BESS optimally configured between 1 MW and 2MW would have a MWh/MW ratio between 3.25 and 5.25, which would be consistent with the optimal ratios identified in the BESS Electric Supply Capacity analysis.

Table 3-124: BESS kWh to Reduce Transformer Peak

Peak Day Time	Peak Load (kW)	Max. LF. Discharge (kW)	Peak Reduction (%)	Peak Day Hours of Operation	Days of Battery Operation	Total Hours of Operation	Peak Day Energy (kWh)	Battery Capacity kWh	Ratio
8/25 5:00 PM	29,928	250	0.84%	1	1	1	250	313	1.25
		500	1.67%	3	1	3	784	980	1.96
		750	2.51%	4	1	4	1,630	2,038	2.72
		1,000	3.34%	4	1	4	2,630	3,288	3.29
		1,250	4.18%	6	1	6	3,857	4,821	3.86
		1,500	5.01%	6	2	7	5,357	6,696	4.46
		1,750	5.85%	6	2	9	6,857	8,571	4.90
		2,000	6.68%	6	2	9	8,357	10,446	5.22
		3,000	10.02%	9	6	26	16,218	20,273	6.76
		4,000	13.37%	11	11	57	26,539	33,174	8.29

Table 3-125 below show the results of the analysis for the residential circuit. This analysis shows that a BESS with a 0.5-MW inverter would require a 2.5-MWh battery to achieve the 5% peak load reduction. The table also shows that for this circuits load profile, an optimally configured BESS larger than 0.5 MW would need to be configured with considerable storage with MWh/MW ratios significantly above 5.0, which could be an uneconomical deployment configuration.

Table 3-125: BESS kWh to Reduce Residential Peak

Peak Day Time	Peak Load (kW)	Max. LF. Discharge (kW)	Peak Reduction (%)	Peak Day Hours of Operation	Days of Battery Operation	Total Hours of Operation	Peak Day Energy (kWh)	Battery Capacity kWh	Ratio
7/9 5:00 PM	10,185	125	1.23%	3	1	3	335	419	3.35
		250	2.45%	3	1	3	710	888	3.55
		500	4.91%	5	2	9	1,850	2,313	4.63
		750	7.36%	7	4	16	3,393	4,241	5.66
		1,000	9.82%	8	4	23	5,230	6,538	6.54
		1,250	12.27%	9	7	35	7,431	9,289	7.43
		1,500	14.73%	9	11	57	9,681	12,101	8.07
		1,750	17.18%	11	11	78	12,324	15,405	8.80
		2,000	19.64%	11	16	103	15,074	18,843	9.42

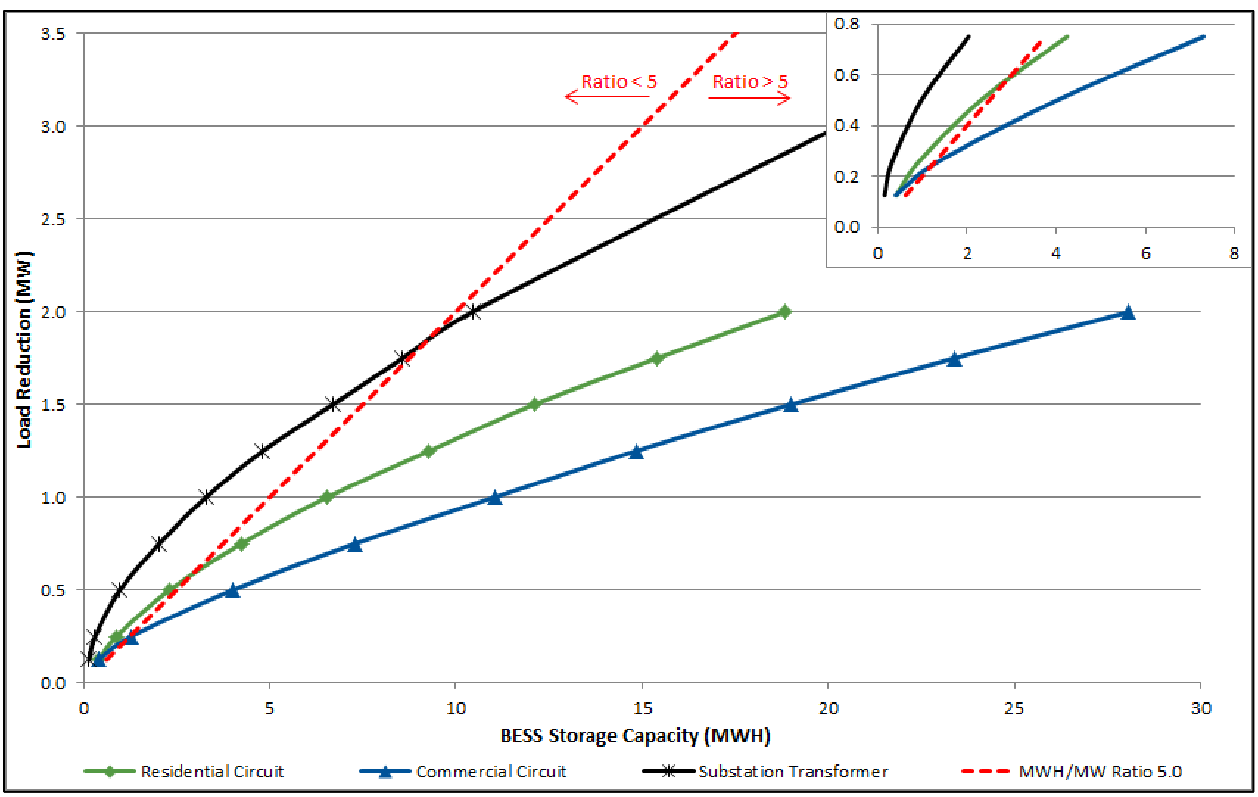
Table 3-126 below show the results of the analysis for the commercial circuit. This analysis shows that a BESS with a 0.5-MW inverter would require a 4.0-MWh battery to achieve a 7.5% peak load reduction. This BESS configuration to achieve this minimal load reduction would have a MWh/MW ratio of 8.0, which could lack economic viability.

Table 3-126: BESS kWh to Reduce Commercial Peak

Peak Day Time	Peak Load (kW)	Max. LF Discharge (kW)	Peak Reduction (%)	Peak Day Hours of Operation	Days of Battery Operation	Total Hours of Operation	Peak Day Energy (kWh)	Battery Capacity (kWh)	Ratio
4/30 4:00 PM	6,725	125	1.86%	5	1	5	324	405.0	3.24
		250	3.72%	7	1	7	1,026	1,283	5.13
		500	7.43%	10	2	12	3,218	4,023	8.03
		750	11.15%	11	2	14	5,836	7,295	9.73
		1,000	14.87%	12	2	15	8,827	11,034	11.03
		1,250	18.59%	13	2	17	11,877	14,846	11.88
		1,500	22.30%	14	3	22	15,197	18,996	12.66
		1,750	26.02%	15	14	82	18,712	23,390	13.37
		2,000	29.74%	15	27	169	22,462	28,078	14.04

Figure 3-183 is a graph of data from the previous tables and shows the BESS storage capacity required to achieve various levels of peak load reduction. The figure generally shows that a BESS with a MWh/MW ratio of 5.0 can achieve its MW rating in peak load reduction for substations, and that to achieve rated KW reduction for individual circuits may typically require the BESS to be configured with MWh/MW ratios significantly greater than 5.0.

Figure 3-183: Peak Load Reduction vs. Storage Capacity



3.4.9.3.2.5 Impact of Distributed Solar PV Generation

The previous analysis showed that to achieve significant levels of peak curtailment on residential and commercial circuits with load profiles similar to those studied, a BESS would be required to discharge in load a significant amount of stored energy over an extended period, often 4 to 12 hours. Configuring a BESS to deliver this amount of energy likely would be cost prohibitive. The project team performed an additional analysis to determine if a modest level of distributed solar PV generation would alter the capability of a BESS to provide T&D peak load reduction. The solar PV generation profile developed in the Distributed Rooftop Solar Generation operational test was used for this analysis.

Figure 3-184 and Table 3-127 summarize the results of this analysis for the substation transformer. This analysis shows that a 15% solar penetration (4.5 MW) would result in a 5% reduction in transformer loading at peak, shifting the peak hour from 4 PM to 7 PM. The analysis also shows that for the solar-adjusted transformer's load profile, an optimally configured 1.5-MW/6.0-MWh BESS, operating in load following mode over 6 hours, could achieve a 5% reduction in transformer peak load. Combined, the solar and BESS could achieve a 10% reduction in the transformer peak load.

Figure 3-184: Solar Adjusted Transformer Peak

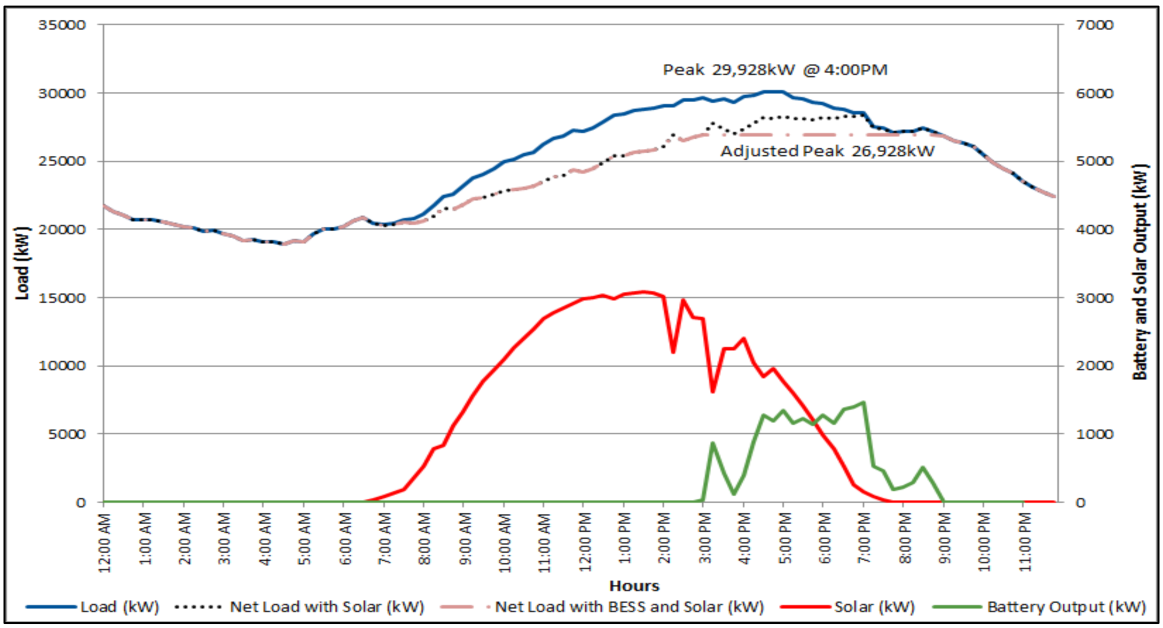


Table 3-127: Solar Adjusted Transformer Peak Analysis

Metric	Value
Original Transformer Peak	29,928 kW @ 4:00PM
Solar Capacity (15% peak)	4,489 kW
Solar Peak	3,077 kW @ 1:30 PM
Solar Adjusted Transformer Peak	28,391 kW @ 7:00 PM
Battery Discharge Duration	6 Hrs; 3:00 – 9:00 PM
Max. Battery Discharge	1,463 kW @ 7:00 PM
Battery Adjusted Transformer Peak	26,928 kW
% Peak Reduction with Battery	5.12 %
% Peak Reduction with Solar and Battery	10.0%
Total Battery Discharge	4,800 kWh
Total Battery Capacity Required	6,000

Figure 3-185 and Table 3-128 summarize the results of this analysis for the residential circuit. This analysis shows that a 15% solar penetration (1.5 MW) would result in less than a 1% reduction in circuit loading at peak but shifts the peak hour from 5 PM to 7 PM. The analysis also shows that for the solar adjusted residential circuit load profile, an optimally configured 1.0-MW/4.0-MWh BESS, operating in load following mode over 7 hours, could achieve a 9% reduction in circuit peak load. Combined, the solar and BESS could achieve a 9.8% reduction in the circuit peak load. This BESS with a MWh/MW ratio of 4.0 is consistent with the optimal ratios identified in the BESS Electric Supply Capacity analysis.

Figure 3-185: Solar Adjusted Residential Circuit Peak Day

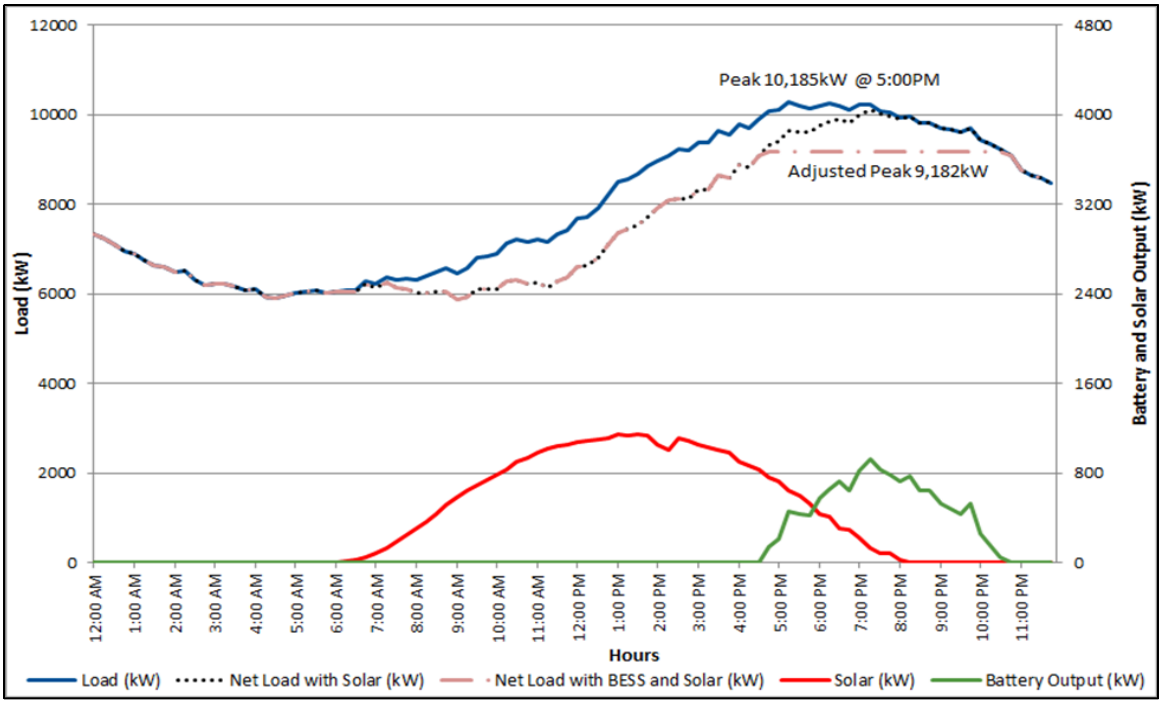


Table 3-128: Solar Adjusted Residential Circuit Peak Analysis

Metric	Value
Original Circuit Peak	10,185 kW @ 5:00 PM
Solar Capacity (15% peak)	1,528 kW
Solar Peak	1,140 kW @ 1:30 PM
Solar Adjusted Circuit Peak	10,105 kW @ 7:15 PM
Battery Discharge Duration	7 hours; 4:00 PM - 11:00 PM
Max. Battery Discharge	923 kW @ 7:15PM
Battery Adjusted Circuit Peak	9,182 kW
% Peak Reduction with Battery	9.1 %
% Peak Reduction with Solar and Battery	9.8 %
Total Battery Discharge	3,200 kWh
Total Battery Capacity Required	4,000 kWh

Figure 3-186 and Table 3-129 summarize the results of this analysis for the commercial circuit. This analysis shows that a 15% solar penetration (0.85 MW) would result in a modest 1.3% reduction in circuit loading, with only a slight shift in the timing of the peak load. The analysis also shows that for the solar adjusted commercial circuit load profile, a 1.0-MW/4.0-MWh BESS, operating in load following mode over 12 hours, could achieve a 10% reduction in circuit peak load. Combined, the solar and BESS could achieve an 11.5% reduction in the circuit peak load. This BESS, with a MWh/MW ratio of 4.0, is consistent with the optimal ratios identified in the BESS Electric Supply Capacity analysis.

Figure 3-186: Solar Adjusted Commercial Circuit Peak Day

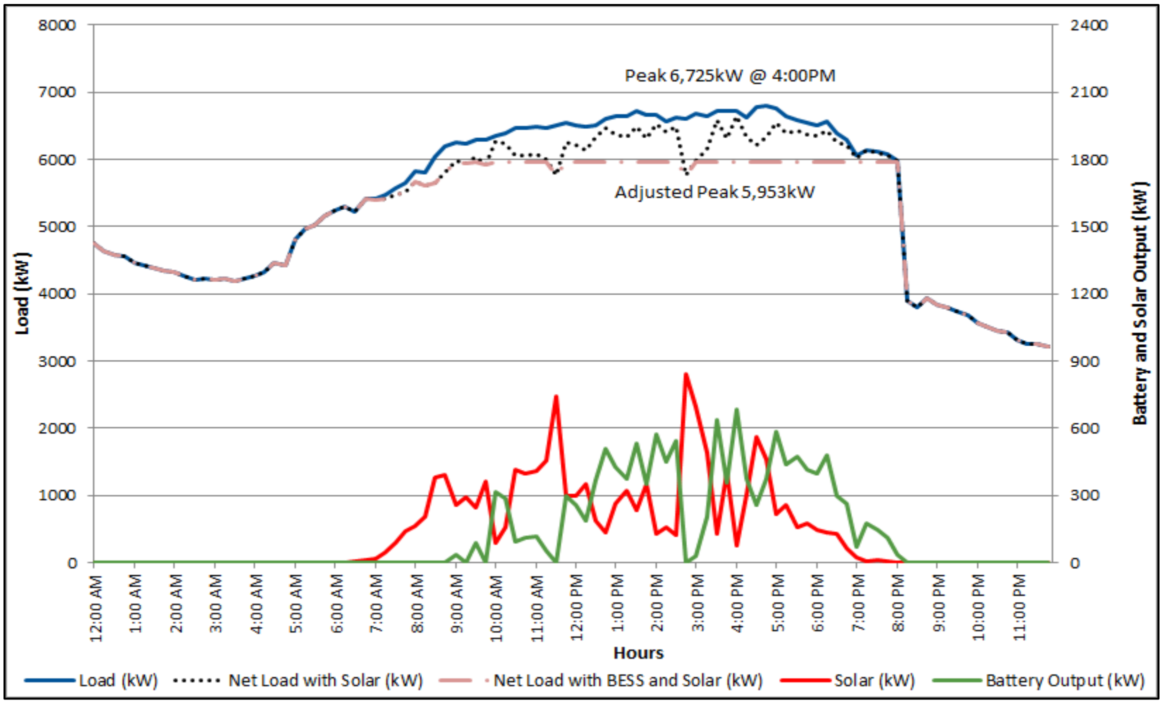


Table 3-129: Solar Adjusted Commercial Circuit Peak Analysis

Metric	Value
Original Circuit Peak	6,725 kW @ 4:00 PM
Solar Capacity (15% peak)	1,009 kW
Solar Peak	843 kW @ 2:45 PM
Solar Adjusted Circuit Peak	6,636 kW @ 4:45 PM
Battery Discharge Duration	12 hours; 9:00 AM - 9:00 PM
Max. Battery Discharge	683 kW @ 4:00PM
Battery Adjusted Circuit Peak	5,953 kW
% Peak Reduction with Battery	9.8 %
% Peak Reduction with Solar and Battery	11.5 %
Total Battery Discharge	3,200 kWh
Total Battery Capacity Required	4,000 kWh

3.4.9.3.2.6 Issues and Corrective Actions

The following issues and corrective actions were encountered during the performance of the T&D Upgrade Deferral operational testing and analysis.

Table 3-130: Issues and Corrective Actions

Issue	Corrective Action
• Per manufacturer recommendation, battery should not be routinely discharged below 20% of rating.	• Limited scheduled BESS discharge to 800 kW. • Set minimum threshold to 15% of capacity for discharge events.
• BESS SMS did not provide a load-following function, but did provide a DNP point to externally control SMS output.	• Team implemented a rudimentary load, following an algorithm in a local controller to manage the SMS output.
• Other operational demonstrations, testing, and analyses precluded dispatching BESS during T&D peak times.	• Performed the BESS T&D load following demonstration as scheduling allowed, but analyzed the impact of event as if it had occurred at peak.
• Circuit to which the BESS was connected was not a good representation of either residential or commercial circuits.	• Performed the BESS T&D Upgrade deferral following analysis on SGDP transformer and circuits that were more representative than typical urban circuits.
• Residential and commercial circuits required the BESS to be configured with a high MWh/MW ratio for MW reduction.	• Performed additional analysis to evaluate the impact of distributed Solar PV generation on MWh/MW ratios for T&D Upgrade Deferral.

3.4.9.3.3 Findings

The results obtained in the execution and analysis phase of the T&D Upgrade Deferral operational testing are summarized in the sections below.

3.4.9.3.3.1 Discussion

The 1.0-MW/1.0-MWh grid-connected BESS is only capable of discharging 80% of its rated storage capacity. Therefore the BESS — by discharging 800 kWh in Load Following Mode — is only capable of reducing the respective T&D component peak loads as follows:

- Substation Transformer 505 kW with LF discharge over 3 hours
- Residential Circuit 7571 280 kW with LF discharge over 3 hours
- Commercial Circuit 7514 217 kW with LF discharge over 5 hours

The BESS Storage Management System (SMS) did not provide a load following function, so to demonstrate this function the project team implemented a rudimentary load-following algorithm in a local controller. Although not as tight as expected, the AMI 15-minute interval data showed that the load following algorithm generally maintained the circuit load at the desired level. While the local controller could rapidly alter the SMS outputs, the wide fluctuations in local load — in conjunction with the relay deadband settings — made it virtually impossible for the local controller to precisely maintain the circuit loading at the desired load following threshold setting.

To determine of the potential of a BESS to provide T&D capacity reductions, the project team selected a representative substation transformer, residential circuit, and commercial circuit on which to perform the analysis. The annual hourly load profile data for these circuits was collected evaluated under normal and contingency switching conditions. Most distribution circuit capacity constraints occur during contingency switching operation. Therefore, the majority of the capacity reduction analysis was performed during the circuit peaks created during contingency switching operations.

The analysis, summarized in Table 3-131, shows the BESS configuration that could provide an approximate 5% reduction in peak load. To achieve peak reduction greater than 5% would require the BESS to be discharged over a significant portion of the day (8+ hours) and be configured with an MWh/MW ratio greater than 5.0, which could be economically unviable.

Table 3-131: BESS kWh to Reduce Peak by 5%

Distribution Component	Peak Load (kW)	Max. LF. Discharge (kW)	Peak Reduction (%)	Peak Day Hours of Operation	Days of Battery Operation	Total Hours of Operation	Battery Capacity kWh	Ratio
Sub. Transformer	29,928	1,500	5.01%	6	2	7	6,696	4.46
Residential Ckt.	10,185	500	4.91%	5	2	9	2,313	4.63
Commercial Ckt.	6,725	500	7.43%	10	2	12	4,022	8.03

While each distribution constraint had different characteristics, the analysis showed that to achieve significant levels of peak curtailment on residential and commercial circuits with load profiles similar to those studied would require a BESS to discharge in load a significant amount of stored energy over an extended period, often 4 to 12 hours. Configuring a BESS to deliver this amount of energy is likely cost prohibitive.

The project team performed an additional analysis to determine if a modest level (15%) of distributed solar PV generation would alter the capability of a BESS to provide T&D peak load reduction. Generally the addition of the solar reduced the mid-day loads, reducing the peak load somewhat, and created a new peak hour later in the day — 7 PM for the transformer and residential circuit. The analysis, summarized in Table 3-132, shows that BESS configurations with 4.0 MWh/MW ratios when combined with the solar PV could provide a 10% reduction in peak loads.

Table 3-132: BESS kWh to Reduce Peak by 10%

Distribution Component	Peak Load (kW)	Peak w/PV (kW)	Inverter Capacity (MW)	Battery Capacity (MWh)	Peak Day Hours of Operation	Peak Reduction (kW)	ES Peak Reduction	PV & ES Peak Reduction
Sub. Transformer	29,928	28,391	1.5	6.0	6	1,463	5.1 %	10.0 %
Residential Ckt.	10,185	10,105	1.0	4.0	7	923	9.1 %	9.8 %
Commercial Ckt.	6,725	6,636	1.0	4.0	12	683	9.8 %	11.5 %

As mentioned previously, the ability of a BESS to defer T&D capacity investments is very site specific and varies greatly based on the load profile of the loads at the point of congestion. These examples show that commercial circuits, with much flatter load profiles, will require a BESS to be configured with significantly more battery storage to achieve a significant amount of congestion relief. For these situations a BESS alone may not be economical, but when combined with other demand-response and distributed generation, an optimally sized BESS could become a part of an economical T&D capacity deferral solution.

Figure 3-186 also illustrates additional challenge that that the intermittency of distributed PV generation introduces to managing circuit loading. In this example, the commercial circuit was experiencing a peak loading condition following contingency switching the previous day. In this case the solar PV intermittency increased the fluctuation of the circuit load but did not significantly shift the daily load pattern and peak load time. However, even with the intermittency the solar generation that was produced allowed the BESS to provide a slightly larger peak reduction with fewer energy-storage requirements.

3.4.9.3.3.2 Expectations vs. Actuals

The following table provides a comparison of the Expected Results and the Actual Outcomes for the T&D Upgrade Deferral operational test.

Table 3-133: Expected Results vs. Actual Outcome

Expected Results	Actual Outcome
• Demonstrate load following discharge of battery based on real-time transformer, bus, and circuit loadings.	• The BESS was used to demonstrate load-following operation based on real-time transformer, bus, and circuit loadings. • Load-following precision of the BESS was limited by the relay deadband settings and variability of local loads.
• Using several representative company distribution circuit load profiles, determination of a representative distribution circuit peak reduction (kW) that could be achieved for a 1-MWh battery.	• Determined T&D upgrade deferral potential for the project's 1.0MWh battery. • Also calculated the T&D upgrade deferral potential for the BESS with various MW/MWh configurations.

3.4.9.3.3.3 Computational Tool Factors

The following table lists the values derived from the T&D Upgrade Deferral operational test analysis that will be used as inputs to the SmartGrid Computational Tool and the Energy Storage Computational Tool.

Table 3-134: Computational Tool Values

Name	Description	Value
Distribution Capacity Deferred (kVA)	The size of the distribution investment deferred as a result of installing energy storage.	500 kVA
Capital Carrying Charge of Distribution Upgrade	The total capital cost of distribution system investments that can be deferred as a direct result of the project.	$ 159,634
Distribution Investment Time Deferred	The time in years that the distribution investment will be deferred.	5 yr
Capital Cost of Deferred Distribution Capacity ($/KVA) (ESCT)	The base overnight capital cost of the deferred transmission investment.	$ 319.26

- <u>Capital Carrying Charge of Distribution Upgrades</u> ($) – Using an incremental distribution deferral method this value is calculated as follows:
  Dist. Capacity Deferred (kVA) x Typical Cost of Dist. Capacity ($/kVA) x Life Cycle Value Multiplier =
  500 kVA x $23.94/kW x 13.3362 = $159,634
- <u>Distribution Investment Time Deferred (Yr.)</u> – The distribution investment deferral is assumed to be 5 years due to the fact that the team is using an incremental calculation and aggregating all incremental distribution deferral components into a single SGCT value.

- Capital Cost of Deferred Distribution Capacity (ESCT) ($) – Using an incremental distribution deferral method this value is calculated as follows:

Typical Cost of Dist. Capacity ($/kVA) x Life Cycle Value Multiplier =
$23.94/kW x 13.3362 = $319.26

3.4.9.3.4 Lessons Learned

Throughout the conduct of the operational testing and analysis of the BESS for Transmission and Distribution Upgrade Deferral function, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- Confirmed that manufacturer's recommendation that the battery should not be routinely discharged below a 20% charge level to protect the battery and maintain its life. This limitation must be factored in when sizing the battery storage component for any BESS.
- The ability of a BESS to defer T&D capacity investments is very site specific and will vary greatly based on the load profile at the point of congestion. This analysis shows that a BESS alone may produce a 5% reduction in distribution transformer and circuit peak loading.
- In many cases, using a BESS alone for T&D Upgrade Deferral may not be economical, but when combined with other demand-response and distributed-generation programs, an optimally sized BESS could become a part of an economical T&D Upgrade Deferral solution.
- Based on the demonstration's analysis it appears that a BESS optimally sized for T&D Upgrade Deferral would have a 0.5-MW to 2.0-MW inverter paired with four to five times the inverter rating in MWh battery storage.

3.4.9.4 Time-of-Use Energy Cost Management

For the Time-of-Use (TOU) Energy Cost Management application, energy end users (utility customers) could use a Premise Energy Storage System (PESS) to reduce their overall costs for electricity. They would accomplish this by charging the storage during Off-Peak periods, when the electric energy price is low, then discharge the energy during times when On-Peak TOU energy prices apply. This application is similar to Electric Energy Time Shift application, although electric energy savings are based on the customer's retail tariff, whereas the benefit for Electric Energy Time Shift is based on the prevailing wholesale price.

3.4.9.4.1 Overview

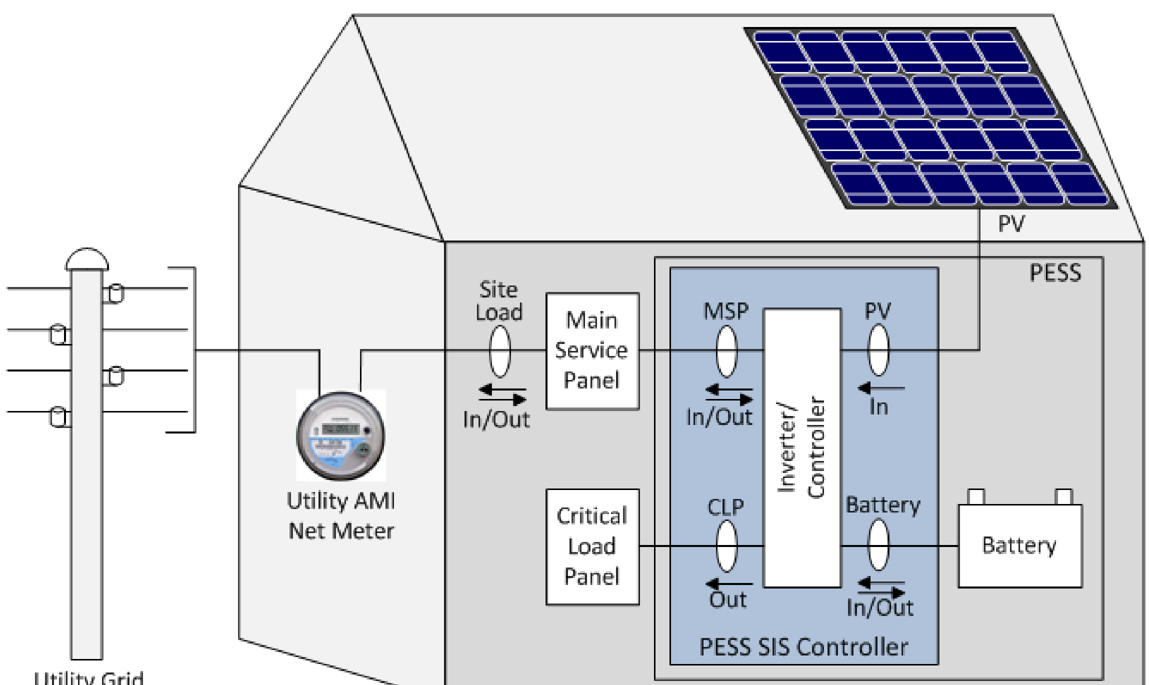
The following sections provide an overview of the operational, demonstration, testing, and evaluation methodology used for the Time-of Use Energy Cost Management operational test.

3.4.9.4.1.1 Description

A consumer PESS was installed at the SmartGrid Demonstration House in conjunction with the 2.82-kW solar PV array. The PESS consists of an 11.7-kWh lithium-ion battery with a unique hybrid inverter/converter rated for 6.0-kW discharge.

The PESS was configured as illustrated in Figure 3-187 and was used to demonstrate how the consumer could use the PESS in conjunction with multitier TOU rates to reduce the consumer's overall cost for electricity. This was accomplished by charging the PESS battery during Off-Peak periods, when the electric energy price is low, and then discharging the battery during times when On-Peak TOU energy prices apply.

Figure 3-187: PESS Installation at SmartGrid Demonstration House



3.4.9.4.1.2 Expected Results

This technical demonstration was expected to yield the following:

- Typical daily charge/discharge load cycles for TOU Energy Cost Management would be developed and demonstrated at the Demonstration House.
- The Round Trip Efficiency factor of the PESS factor for TOU Energy Cost Management would be determined. The system would be expected to operate at greater than 70% efficiency with respect to net energy output versus input.
- The Total Energy Discharged for TOU Energy factor for the PESS would be determined. The system would be expected to have approximately 10 kWh available daily for TOU discharge.
- The charge/discharge load cycles developed would be mathematically applied to a load profile for a typical residential customer to illustrate how a PESS system could be used with TOU rates to lower the customer's energy cost.

3.4.9.4.1.3 Benefit Analysis Method/Factors

The DOE SGCT was used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits were quantified.

- Deferred Generation Capacity Investments
- Deferred Distribution Capacity Investments
- Reduced Electricity Costs

Benefits were calculated using SGCT formulas. The following factors were measured, projected or calculated during the application operation and/or demonstration.

Deferred Generation Capacity Investments (Utility)

- Energy Storage Use at Annual Peak Time (MW)

Deferred Distribution Capacity Investments (Utility)

- Distribution Feeder Load Reduction (MW)
- Capital Carrying Charge of Distribution Upgrade ($)

Reduced Electricity Costs (Customer)

- Reduced Total Residential Electricity Cost ($)

Additionally, the DOE ESCT was used to perform the benefit analysis for a customer owned PESS system. The following Stationary Energy Storage applications were combined in this analysis.

- Primary Application – Time-of-Use Energy Cost Management
- Secondary Application – Renewable Energy Time Shift
- Secondary Application – Electric Service Reliability

Primary Benefit for TOU Energy Cost Management:

- Reduced Electricity Cost (Consumer)

3.4.9.4.1.4 Testing Methodology

The following points provide an overview of how the operational demonstration and testing for this application was accomplished:

- Energy delivered to and received from the PESS was measured by the PESS Solar Integration System (SIS). All PESS data collected was stored in the SIS data archive.

- Energy delivered to and received from the customer's electrical system by the utility distribution grid was measured by the AMI net meter installed at the customer service entrance. All AMI data collected was stored in KCP&L's MDM and DMAT systems.
- A daily charge/discharge program was implemented to demonstrate and evaluate the operational benefit of using the PESS. Charging occurred daily from 9:00 PM to 12:00 AM and discharge occurred from 1:00 AM to 5:00 AM. This nighttime daily/charge discharge cycle was used so that data collection for this operational test could be conducted in parallel with data collection for Renewable Energy Shift Time Shift analysis.
- The PESS was operated in this mode at least two weeks to determine the Round Trip Efficiency of the battery storage system factor.

3.4.9.4.1.5 Analytical Methodology

The following points provide an overview of the analytical methods that were used to evaluate the impact and benefits of this application:

- 1-minute interval energy (AC watts) delivered to and received from the customer's electrical system (MSP) by the PESS was recorded by the PESS SIS.
- 1-minute interval energy (AC watts) delivered to the customer's emergency critical load panel (CLP) by the PESS was recorded by the PESS SIS.
- The functionality of the PESS SIS was used to aggregate the 1-minute interval data to 15-minute interval data and was exported to Excel for analysis.
- The daily charge/discharge cycles were analyzed to determine the potential maximum energy that could be discharged and stored, and the round trip efficiency of the battery charge/discharge cycle.
- The Daily Round Trip Efficiency of PESS was calculated as the Daily Energy Delivered to the utility and customer load/Daily Energy Received from the utility.
- The SmartGrid Demonstration House is not a typical residential customer. Therefore a typical residential customer was selected to analyze the PESS charge and discharge cycle.
- The Reduced Electricity Cost for the consumer was calculated for inclusion in the Smart Grid Computational Tool and Energy Storage Computational Tools.

3.4.9.4.2 Plan Execution and Analysis

The following sections provide details regarding the functional tests performed, data collected, and analysis performed for the Time-of-Use Energy Cost Management operational test.

3.4.9.4.2.1 Daily Block Charge and Discharge Operation

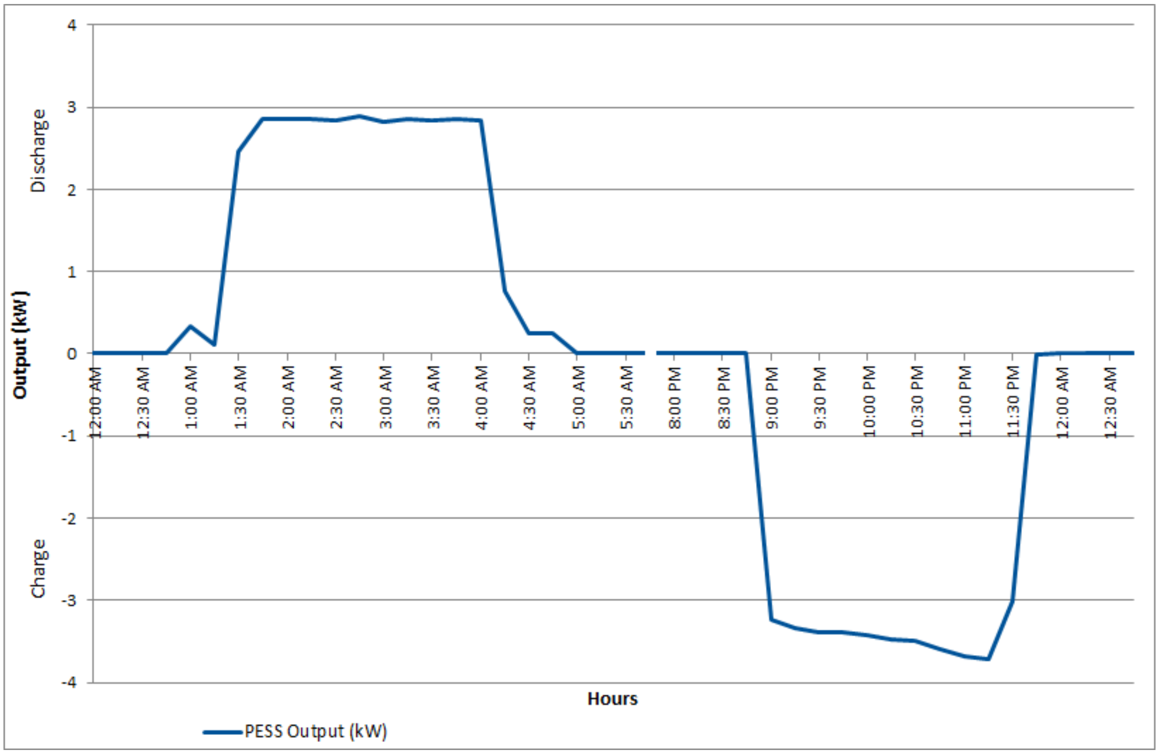
A review of the manufacturer's operation manual identified a recommendation that the battery should not be routinely charged above 95%, and should not be discharged below 10% charge level, to protect the battery and maintain its useful life. The manual also included a recommendation for reserving 10% battery capacity for UPS mode. These operational constraints limit the operational output of the 11.7-kWh Lithium polymer battery for routine application use to 8.75 kWh.

The PESS was set to charge daily from 9 PM to 12 AM and discharge from 1 AM to 5 AM local time. To achieve a full charge and discharge, the following settings were configured in the SMS:

- The SIS discharge rate was set at 45% of inverter capacity, or 2.7 kW, to deliver approximately 9 kWh during the 4-hour discharge period.
- The SIS charge rate was set at 66% of inverter capacity, or 3.96 kW, to provide a full charge, up to 11.7 kWh, during the 3-hour charge period.

Figure 3-188 shows the 15-minute interval daily block charge and discharge cycles under these settings. During idle hours, the utility grid supplies load to the house for the critical load and main load.

Figure 3-188: PESS Daily Block Charge and Discharge Profile



As illustrated in the figure above, the battery starts to charge and slowly increases the charge rate over a period of 3 hours. The SIS calculates the state of charge for the battery, and increases the charge rate if the battery is not close to its full state of charge.

3.4.9.4.2.2 Daily Round Trip Efficiency of the PESS

At the beginning of the project, it was expected that the PESS would operate at efficiency greater than 70% with respect to net energy output versus input. The SIS records the energy delivered to the grid, energy received from the grid, and energy delivered to the critical load at the site. The purpose of this analysis is to verify the round trip efficiency of PESS.

Based on the daily charge and discharge cycle, the round trip efficiency of the PESS is calculated as:

$$RTE\ of\ PESS = \frac{Energy\ discharged\ from\ PESS}{Energy\ required\ to\ charge\ PESS\ + Energy\ received\ during\ idle\ hours} \times 100\%$$

The energy discharged from PESS is calculated as the sum of energy delivered to the grid and the critical load panel at the site. The energy required to charge PESS is calculated as the difference of energy from the grid and energy delivered to the critical load panel on site. Energy received during idle hours is the difference of energy from the grid and energy delivered to the critical load panel on site when the PESS is non-operational.

Table 3-135 shows the energy delivered by the grid to charge PESS, energy discharged by the PESS, energy received during idle hours, and round trip efficiency of PESS. These values were measured over several days. The daily round trip efficiency varied from 80.9% to a maximum of 96.1%, with average efficiency of 86.4%.

Table 3-135: Daily Round Trip Efficiency of the PESS

Date	Discharge (kWh)	Charge (kWh)	Idle hours (kWh)	Efficiency
Sept. 04	9.09	9.36	0.087	96.16%
Sept. 07	8.16	9.44	0.056	85.97%
Sept. 13	8.38	9.23	0.045	90.38%
Sept. 16	8.10	9.38	0.052	85.88%
Sept. 21	7.92	9.31	0.060	84.56%
Sept. 25	7.84	9.63	0.059	80.97%
Sept. 29	7.97	9.57	0.062	82.74%
Oct. 02	8.00	8.70	0.067	91.32%
Oct. 08	7.98	9.13	0.051	86.92%
Oct. 16	7.80	9.21	0.044	84.34%
Oct. 23	7.86	8.90	0.059	87.69%
Oct. 28	7.91	9.13	0.117	85.53%
Average	**7.98**	**9.17**	**0.062**	**86.45%**

3.4.9.4.2.3 Potential Utility System and Distribution Peak Reduction

The PESS can be operated in multiple ways that would affect the utility capacity requirements. First, the customer could participate in a utility Demand Response program or allow the utility to dispatch the PESS for Demand Response. For Demand Response the PESS could potentially supply 6 kW (inverter capacity) for a 1-hour duration event; 4.3 kW for a 2- hour duration event; or 2.15 kW for a 4-hour duration event.

Secondly, if KCP&L assumed that the utility's system and distribution peaks occur during the On-Peak TOU billing period, the utility would experience a demand reduction when the customer discharged the battery for TOU Energy Cost Management. For this operational test KCP&L assumed a 4-hour On-Peak billing period, corresponding to the experimental SmartGrid TOU rate implemented for the project.

During the daily charge/discharge cycle, the PESS discharged at a rate of 2.7 kW but did not discharge for a full 4 hours. Table 3-135 shows that the average discharge was 7.98 kWh which, if the settings were tuned further, could deliver 2 kW of customer and utility load reduction for a 4-hour duration.

3.4.9.4.2.4 Customer Energy Usage with PESS Used for On-Peak TOU Cost Management

The SmartGrid Demonstration house electrical usage is not representative of a typical residential customer. Therefore a "typical" residential customer — with an annual usage of 10,319 kWh, approximately 15% more than the average Demonstration Area residential customer (~8,800 kWh) — was selected to analyze customer benefits of the PESS when used for energy cost management.

The daily load profile for such a typical residential customer from the SmartGrid Demonstration area in is shown in Figure 3-189. While no two customers have identical usage patterns, this customer displays a typical daily pattern; minimal usage during the late night, sharp rise to moderate usage in the early morning hours, followed by a mid-morning drop in usage that begins to increase throughout the day, significant peak usage during the On-Peak period, followed by a slightly reduced but sustained moderate usage until midnight.

Figure 3-189: Summer Typical Residential Customer Daily Load Profile

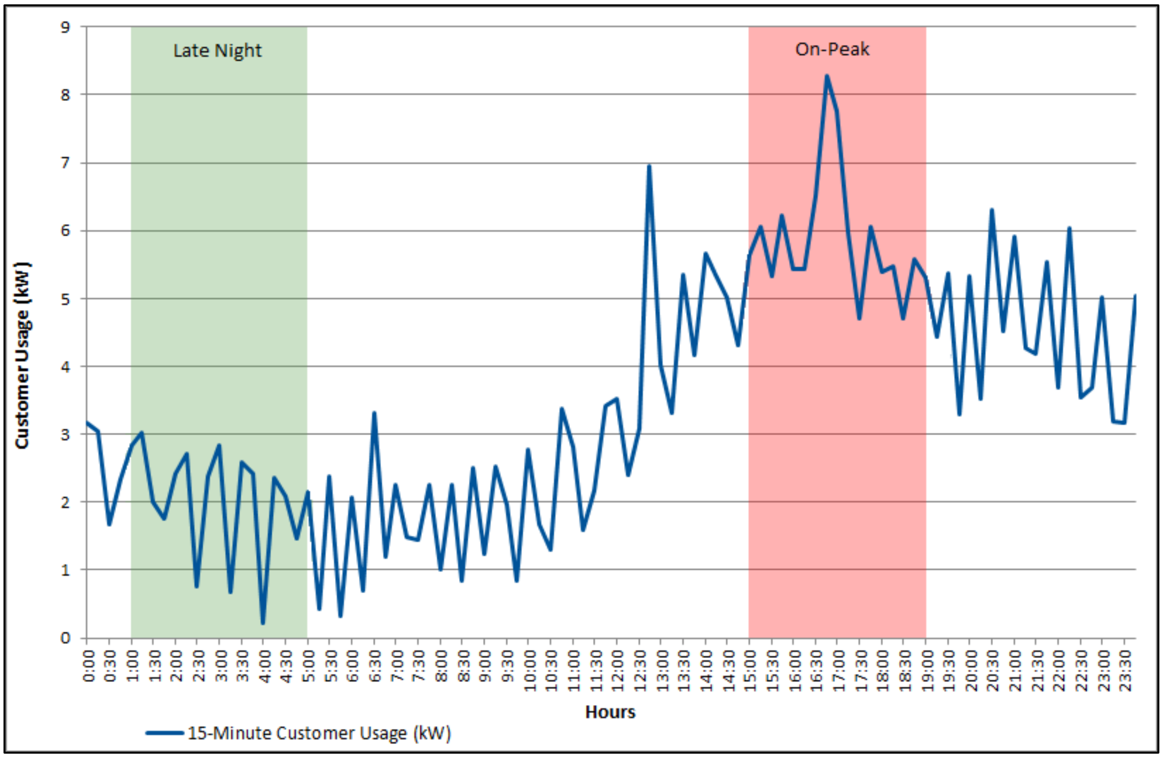


Figure 3-190 shows the weekly kWh usage of this residential customer throughout the year in three usage groupings: Late Night Usage (when the battery would charge), Normal Usage, and On-Peak Usage (when the battery would be discharged).

Figure 3-190: Weekly Typical Residential Customer Usage

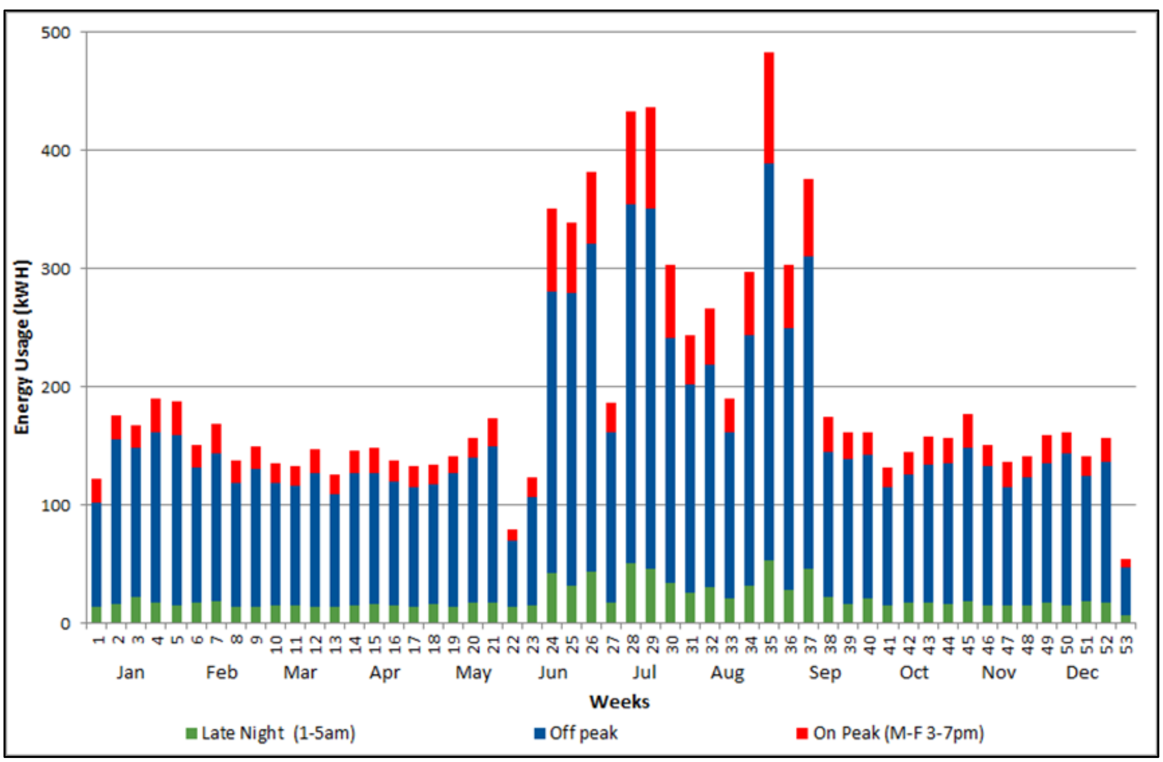


Figure 3-191 shows the shift in daily energy use this residential customer with the maximum PESS block charge/discharge operation applied. The PESS is charged from 1:00 AM to 5:00 AM and discharged from 3:00 PM to 7:00 PM, thus boosting energy usage in the late night and reducing usage during On-Peak hours.

Figure 3-191: Daily Load Profile with PESS Daily Block Operation

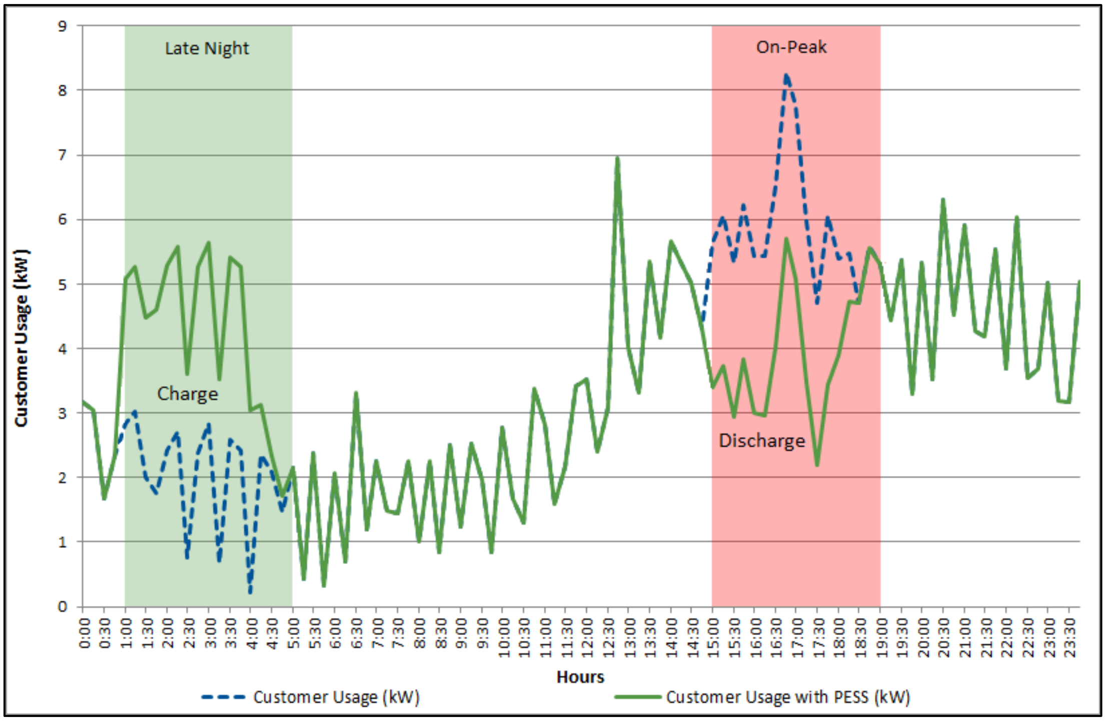


Figure 3-192: Weekly Typical Residential Usage with PESS Block Operation

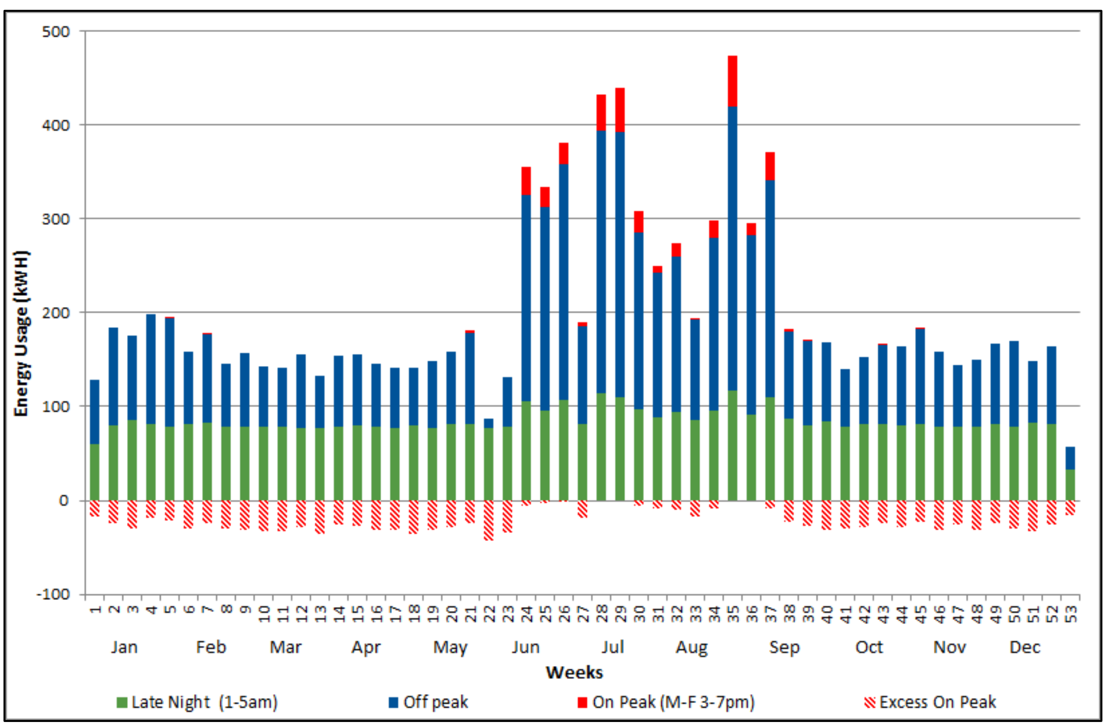


Figure 3-192 above shows the shift in weekly residential customer usage with the PESS block operation. The PESS block discharge during peak hours results in zero to negative consumption (supply to grid) of energy during On-Peak hours. The energy consumption significantly increases during Off-Peak hours when PESS is scheduled to charge to its full potential.

Figure 3-193 shows the shift in daily energy use this residential customer with the maximum PESS load-leveling operation applied. The PESS is charged at a variable rate from 1:00 AM to 5:00 AM and discharged at a variable rate from 3:00 PM to 7:00 PM. With the load-leveling application the variability the customer's load on the grid during the charge and discharge cycles will be minimized and the ability of the customer to fully discharge the PESS without feeding energy back to the grid will be improved.

Figure 3-193: Daily Load Profile with PESS Daily On-Peak Load Leveling Operation

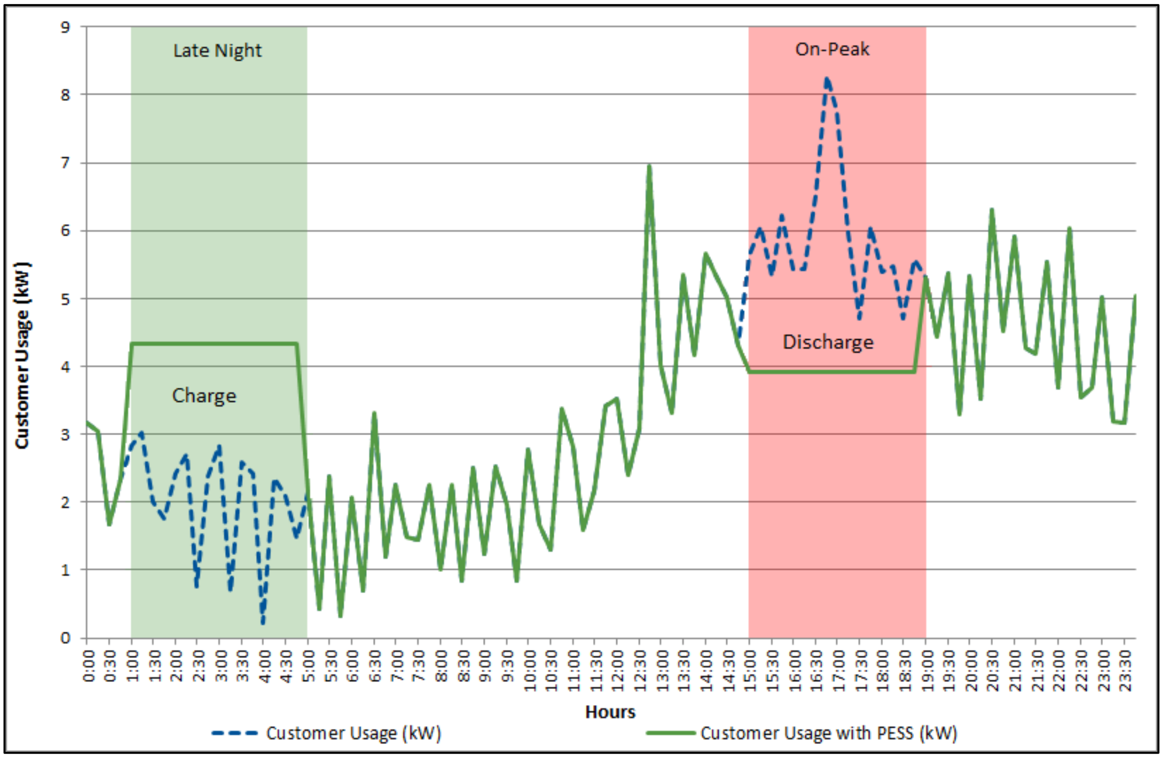


Figure 3-194 shows the shift in weekly residential customer usage with the PESS load-leveling operation. The PESS load-leveling discharge during peak hours results in no negative consumption (supply to grid) and only a few occurrences where the customer's On-Peak usage was low enough that the entire capacity of the PESS could not be fully discharged during the On-Peak period.

Figure 3-194: Weekly Typical Residential Usage with PESS Load-Leveling Operation

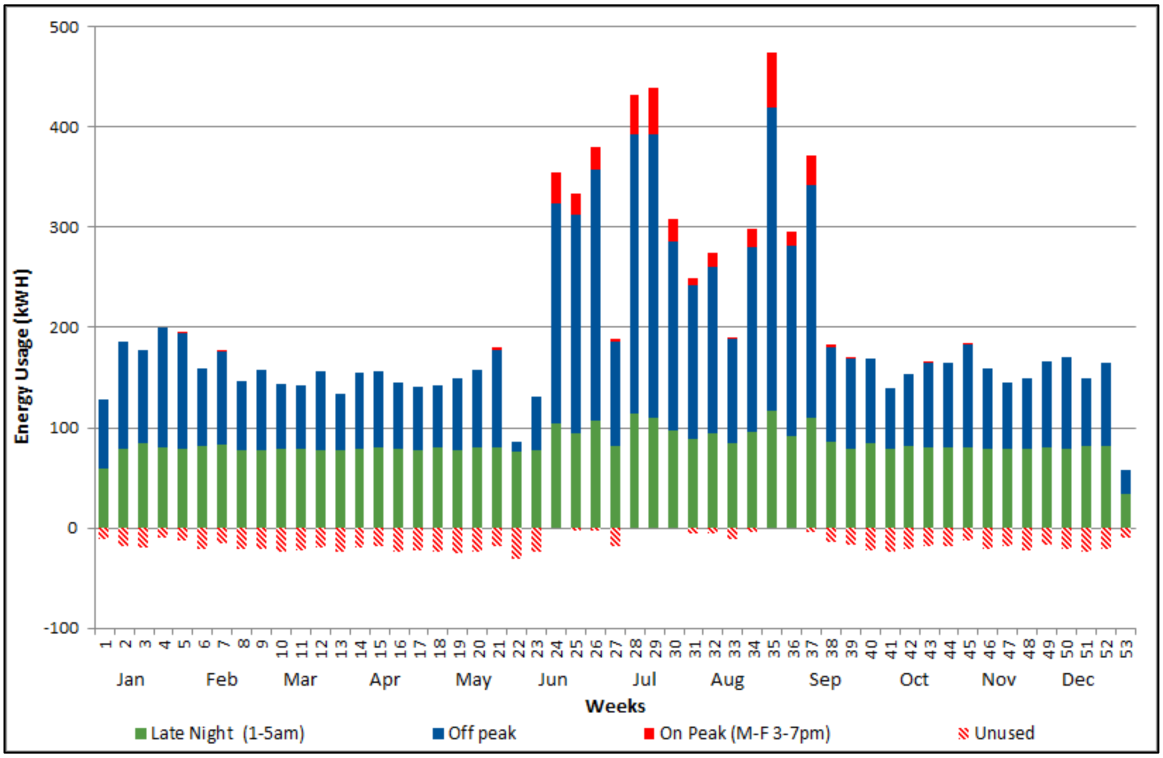


Table 3-136 below summarizes the impact of the PESS on the Late Night and On-Peak energy usage for this residential customer by season. In this table the PESS has been operated in load-leveling mode to maximize the offset of the customer's On-Peak usage and minimize unused PESS energy or energy delivered to the utility.

Table 3-136: Residential Customer Energy Usage per Session with On-Peak Reduction

	Customer Energy Usage Metrics (kWh)	Summer (Jun 16 - Sep 15)	Fall (Sep 16 - Dec 15)	Winter (Dec 16 - Mar 15)	Spring (Mar 16 - Jun 15)	Annual Total
Usage Before PESS	On-Peak Energy (3-7 PM M-F)	757	282	275	280	1,594
	Off-Peak Energy	3,040	1,514	1,541	1,510	7,606
	Late Night Energy (1-5 AM)	459	220	217	223	1,119
	Total Energy	4,256	2,016	2,033	2,013	10,319
With PESS (Load Leveling)	PESS Charge Energy	481	157	177	138	953
	PESS Discharged Energy	416	135	153	120	824
	PESS Unused Energy	88	351	343	379	1,161
Usage with PESS	On-Peak Energy (3-7 PM M-F)	342	147	122	160	771
	Off-Peak Energy	3,040	1,514	1,541	1,510	7,606
	Late Night Energy (1-5 AM)	941	376	394	361	2,072
	Total Energy	4,323	2,037	2,057	2,031	10,448

3.4.9.4.2.5 Customer Cost Savings Potential from PESS with SmartGrid TOU Rate

The TOU rate implemented for the SGDP incorporated a rate differential during the period the KCP&L Summer Rates were in effect. The SmartGrid TOU rate was based on the following parameters:

- Effective Dates – May 15th - Sept. 15th
- On-Peak Times – 3 - 7 PM, Monday-Friday Excluding 3 Holidays
- On-Peak Rate - $0.3784 (approximately 3X the standard summer rate)
- Off-Peak Rate - $0.0631 (approximately half of the standard summer rate)

Based on these TOU program parameters a customer could implement 77 charge/discharge cycles during the period in which the summer On-Peak rates are in effect. Assuming the customer's load was such that the customer could consume the full PESS discharge of 7.98kWh during the On-Peak time, a total of 614.5 kWh could be discharged annually for TOU cost savings. The annual Customer Energy Cost savings would be $187.73 calculated by the following formula:

Reduced Customer Energy Cost ($) = Total Energy Discharged for TOU Energy (kWh) x [Avg. On-Peak Retail Price of Electricity ($/kWh) – Avg. Off-Peak Retail Price of Electricity ($/kWh) / Storage System Round-trip Efficiency (%)]

Reduced Customer Energy Cost ($) = 614.5kWh x [0.3784 $/kWh – (0.0631 $/kWh/0.8645)] = $ 187.73

3.4.9.4.2.6 Customer Cost Savings Potential from PESS with 3 Tier TOU Rate and Net Metering

Analysis in previous sections has covered customer usage and the cost savings impact of operating the PESS to reduce On-Peak energy consumption from the utility. When a PESS is operated in conjunction with solar generation the savings potential between the Time-of-Use Energy Cost Management and the Renewable Energy Time Shift functions can conflict. To achieve maximum TOU Cost Managing savings in conjunction with solar renewable generation, the operation of the PESS for TOU Cost Management must be adjusted to offset On-Peak usage with Late Night usage, which requires a 3-tier TOU rate.

KCP&L could not implement a 3-tier TOU rate for the SGDP due to limitation in the utility's CIS billing system. But to support this analysis, the project team developed a hypothetical year-round 3-tier TOU structure that was revenue neutral with the 2-tier TOU rate outlined in the previous section. The hypothetical TOU rate used for this analysis was based on the following parameters:

- Summer Effective Dates – June 15th - Sept. 15th
- On-Peak Times – 3-7 PM, Monday-Friday Excluding Holidays
- Late Night Times – Midnight -5 AM
- Off-Peak Times – All other time
- Summer On-Peak Rate - $0.336
- Summer Off-Peak Rate - $0.09
- Summer Late Night Rate - $0.03
- Winter On-Peak Rate - $0.225
- Winter Off-Peak Rate - $0.075
- Winter Late Night Rate - $0.025

Table 3-137 below summarizes the impact of the PESS on the Late Night and On-Peak energy usage for this residential customer, by season. Results in this table come from the PESS being operated in block discharge mode to offset of the customer's On-Peak usage and deliver any excess stored energy to the utility.

Table 3-137: Residential Customer Energy Usage with 3 Tier TOU and Net Metering

	Customer Energy Usage Metrics (kWh)	Summer (Jun 16 - Sep 15)	Fall (Sep 16 - Dec 15)	Winter (Dec 16 - Mar 15)	Spring (Mar 16 - Jun 15)	Annual Total
Usage Before PESS	On-Peak Energy (3-7 PM M-F)	757	282	275	280	1,594
	Off-Peak Energy	3,040	1,514	1,541	1,510	7,605
	Late Night Energy (1-5 AM)	459	220	217	223	1,119
	Total Energy	4,256	2,016	2,033	2,013	10,318
PESS	PESS Charge Energy	844	834	825	844	3,347
	PESS Discharged Energy	734	726	718	734	2,913
Usage with PESS	On-Peak Energy (3-7 PM M-F)	246	-229	-220	-239	-441
	Off-Peak Energy	2,817	1,299	1,318	1,295	6,727
	Late Night Energy (1-5 AM)	1,303	1,054	1,042	1,067	4,466
	Total Energy	4,365	2,124	2,140	2,122	10,752

Based on these TOU program parameters a customer could implement 92 charge/discharge cycles (64 On-Peak and 28 Off-Peak) during the summer period and 273 charge/discharge cycles (190 On-Peak and 82 Off-Peak) during the rest of the year. Assuming the PESS performs a full discharge of 7.98 kWh daily, a total of 2,913 kWh could be discharged annually for TOU cost savings. Based on the following calculations, the annual Customer Energy Cost savings would be $ 495.26 if the net metering tariff credits the customer with the full retail rate for any energy delivered back to the utility.

Reduced Customer Energy Cost ($) = Total Energy Discharged for TOU Energy (kWh) x [On/Off-Peak Retail Price of Electricity ($/kWh) – Avg. Late Night Retail Price of Electricity ($/kWh) / Storage System Round-trip Efficiency (%)]

Reduced On-Peak Energy Cost-Summer ($) = 511 kWh x [0.336 $/kWh – (0.03 $/kWh/0.8645)] = $ 153.96
Reduced Off-Peak Energy Cost-Summer ($) = 223 kWh x [0.09 $/kWh – (0.03 $/kWh/0.8645)] = $ 12.33
Reduced On-Peak Energy Cost-Winter ($) = 1,524 kWh x [0.225 $/kWh – (0.025 $/kWh/0.8645)] = $ 298.83
Reduced Off-Peak Energy Cost-Winter ($) = 654 kWh x [0.075 $/kWh – (0.025 $/kWh/0.8645)] = $ 30.14
Reduced Customer Energy Cost = $153.96 + $12.33 + $298.83+$30.14= $495.26

3.4.9.4.2.7 Issues and Corrective Actions

The following issues and corrective action were encountered during the performance of the Time-of-Use Energy Cost Management operational testing and analysis.

Table 3-138: Issues and Corrective Actions

Issue	Corrective Action
• The SmartGrid Demonstration House electrical usage is not representative of a typical residential customer	• The annual load profile of a "typical" residential customer was used for this analysis
• Due to technical issues and conflicting demonstrations at the Demonstration House, KCP&L was not able to achieve annual data collection for this test.	• Daily PESS charge/discharge patterns were modeled and applied to the "typical" residential customer load profile
• KCP&L did not have a 3-tier TOU rate to evaluate Off-Peak reduction scenarios	• Developed a hypothetical 3-tier TOU rate that was revenue neutral for this analysis.

3.4.9.4.3 Findings

The results obtained in the execution and analysis of the Time-of-Use Energy Cost Management operational test are summarized in the sections below.

3.4.9.4.3.1 Discussion

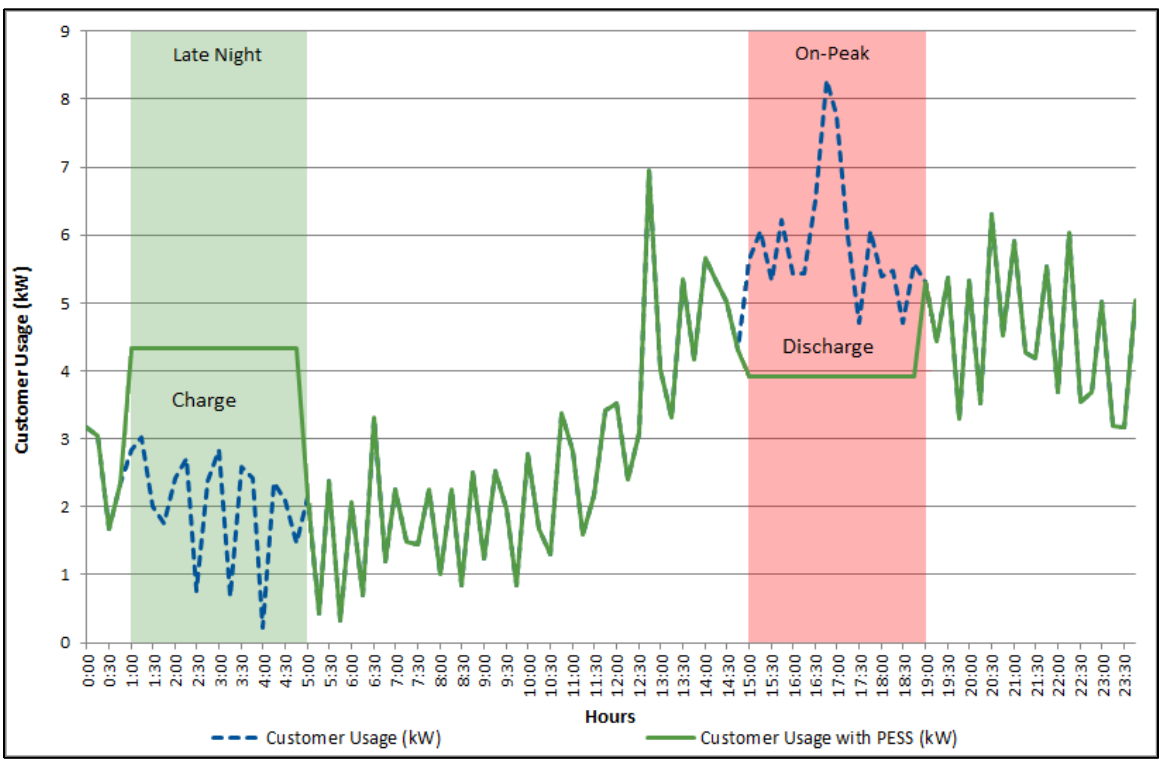
The PESS installed at the Demonstration House is a 11.7-kWh lithium-ion battery with a unique hybrid 6.0 kW inverter/converter, a battery set to charge and discharge daily from the grid. Due to project constraints the daily operation of the PESS for this analysis was performed at night so that the Renewable Energy Time Shift function test could be performed concurrently. The PESS was charged from the grid for 3 hours, from 9 PM to 12 AM local time, and discharged to the grid for 4 hours, from 1 AM to 5 AM local time.

The Round Trip Efficiency (RTE) of the PESS was measured and calculated. The average PESS efficiency was calculated to be 86.4%, higher than the expected efficiency of 70%.

The SmartGrid Demonstration House electrical usage is not representative of a typical residential customer. Therefore a “typical” residential customer, with annual usage of 10,319 kWh, was selected to analyze customer benefits of the PESS when used for energy cost management. The PESS energy charge/discharge cycles were then mathematically applied to this customer’s usage in both block and load-leveling dispatch modes and analyzed for On-Peak grid load reduction. Figure 3-195 illustrates the impact of the PESS when charged from 1 AM to 5 AM during the late night and discharged from 3 PM to 7 PM to offset On-Peak grid load.

Operating in the On-Peak reduction method in conjunction with the parameters of KCP&L’s SmartGrid Demonstration Rate as illustrated in Figure 3-195, the customers annual Late Night energy consumption increased 953 kWh and the On-Peak energy consumption decreased 824 kWh, which would yield the customer annual savings of $188.

Figure 3-195: On-Peak Energy Shift Impact on Typical Residential Load Profile



In the previous analysis the customer usage and cost savings were derived by operating the PESS to reduce On-Peak energy received from the utility. When a PESS is operated in conjunction with solar generation the savings potential between the Time-of-Use Energy Cost Management and the Renewable Energy Time Shift functions can conflict. To achieve maximum TOU Cost Managing savings in conjunction with solar renewable generation, the operation of the PESS for TOU Cost Management must be adjusted to offset On-Peak usage with Late Night usage, which requires a 3-tier TOU rate.

To determine potential PESS TOU Cost Management savings that could be combined with the solar generation and net metering , a hypothetical year round 3-tier TOU structure that was revenue neutral with the 2-tier TOU rate was developed. This hypothetical TOU rate had a 30-cent differential between Late Night and On-Peak rates during a 3 month summer period and a 20-cent differential the rest of the year.

Table 3-137 summarizes the impact of the PESS on the Late Night and On-Peak energy usage for this residential customer, by season. Results in this table come from the PESS being operated in block discharge mode to offset of the customer’s On-Peak usage and deliver any excess stored energy to the utility.

Operating in the Off-Peak reduction method in conjunction with the parameters of hypothetical 3-tier TOU rate, the typical customer’s annual Late Night energy consumption increased 3,347 kWh and the On-Peak energy consumption decreased 2913 kWh, which would yield the customer annual savings of $495 if the net metering tariff credits the customer with the full retail rate for any energy delivered back to the utility

3.4.9.4.3.2 Expectations vs. Actuals

The following table provides a comparison of the Expected Results and the Actual Outcomes for the Time-of-Use Energy Cost Management operational test.

Table 3-139: Expected Results vs. Actual Outcome

Expected Results	Actual Outcome
• Typical daily charge/discharge load cycles for TOU Energy Cost Management will be developed and demonstrated.	• Daily charge/discharge operations for TOU Energy Cost Management were developed and demonstrated.
• The Round Trip Efficiency factor of the PESS factor will be determined, with it expected to be greater than 70%.	• The RTE factor for the PESS was determined to be 86.45%.
• The system is expected to have approximately 10 kWh available daily for TOU discharge.	• With vendor operating guidelines and a 10% reservation for UPS mode (Electric Service Reliability) the 11.7-kWh PESS had 8.75 kWh available for routine application use.
• The charge/discharge cycles developed will be mathematically applied to a “typical” residential customer load profile to illustrate how a PESS system could be used with TOU rates to reduce the customer’s energy cost.	• The charge/discharge cycles were applied to a typical customer load profile and analyzed to show the potential for cost savings with TOU rates.

3.4.9.4.3.3 Computational Tool Factors

The following table lists the values derived from the Time-of-Use Cost Management operational test analysis that will be used as inputs to the Smart Grid Computational Tool and the Energy Storage Computational Tool.

Table 3-140: Computational Tool Values

Name	Description	Calculated Value
Energy Storage Use at Annual Peak Time	The amount of energy storage power available to meet annual peak demand	.002 MW
Capital Carrying Charge of Distribution Upgrade	The total capital cost of distribution system investments that can be deferred as a direct result of the project.	$638
Distribution Investment Time Deferred (years)	The time in years that the distribution investment will be deferred.	5 yrs.
Total Residential Electricity Cost ($) (Avoided)	Total amount of money spent on electricity by residential customers annually.	$495.26
Total Energy Discharged for TOU Energy Cost Management (MWh) (ESCT)	Total amount of energy discharged by the PESS to provide energy during peak-time so as to avoid paying peak prices.	2.913 MWh
Average On-Peak Retail Price of Electricity ($/MWh) (ESCT)	Average On-Peak retail price of electricity. This would be the price that was avoided as a result of the energy storage device.	$200.45 /MWh
Average Off-Peak Retail Price of Electricity ($/MWh) (ESCT)	Average On-Peak retail price of electricity. This would be the price that was avoided as a result of the energy storage device.	$26.26 /MWh

- Capital Carrying Charge of Distribution Upgrades ($) – Using an incremental distribution deferral method this value is calculated as follows:

  Dist. Capacity Deferred (kVA) x Typical Cost of Dist. Capacity ($/kVA) x Life Cycle Value Multiplier =

  2 kVA x $23.94/kW x 13.3362 = $638

- Distribution Investment Time Deferred (Yr.) – The distribution investment deferral is assumed to be 5 years due to the fact that the project team is using an incremental calculation and aggregating all incremental distribution deferral components into a single SGCT value.
- Total Energy Discharged for TOU Energy Cost Management (MWh): This value was extracted from the data presented in Table 3-137:
- Average On-Peak Retail Price of Electricity ($/MWh): This value has been calculated based on a weighted average of the On-Peak and Off-Peak rates and discharge values presented in in Table 3-137.
- Average Off-Peak Retail Price of Electricity ($/MWh): This value has been calculated based on a weighted average of the Late Night rates and discharge values presented in Table 3-137.

3.4.9.4.4 Lessons Learned

Throughout the conduct of the operational testing and analysis of the PESS for the Time-of-Use Energy Cost Management function, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- The manufacturer's recommendations for protecting the battery and maintaining its useful life — that the battery should not be routinely charged above 95%, and should not be discharged below 10% charge— must be factored in when sizing the battery storage component for any PESS.
- Differential in TOU rates needs to be at least 16% for the customer to receive any monetary savings. KCP&L's SmartGrid TOU rate was a 2-tier rate structure limited to four summer months. A PESS could achieve greater savings for the customer with year round 3-tier rates. The PESS benefits could be further maximized when operated in conjunction Renewable Energy Time Shift.
- The PESS demonstrated that it has considerable flexibility in how it can be applied to provide maximum customer benefits, but it must be tailored to the specific customer load profile and rate structure.

3.4.9.5 Renewable Energy Time Shift

The Renewables Energy Time Shift application involves storing electricity from renewable sources when the price of electricity is low and using (or selling) that stored energy when the price of electricity is higher. Because solar typically produces its maximum energy midday when electricity prices are typically lower, the price differential between the electricity used to charge the battery and the electricity sold at peak can be significant. The energy that is discharged from the storage could be sold via the wholesale market, sold under terms of an energy purchase contract, or used by an integrated utility to reduce the overall cost of providing generation during peak times.

3.4.9.5.1 Overview

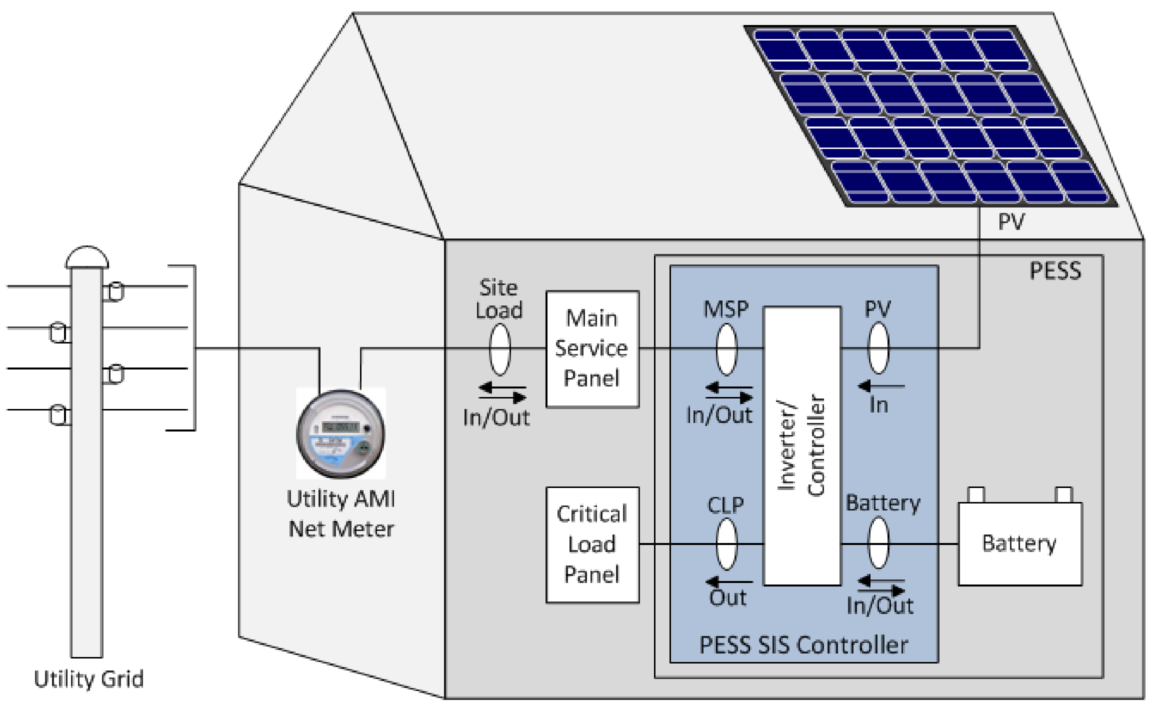
The following sections provide an overview of the operational, demonstration, testing, and evaluation methodology used for the Renewable Energy Time Shift operational test.

3.4.9.5.1.1 Description

A consumer PESS was installed at the SmartGrid Demonstration House in conjunction with the 2.82-kW solar PV array. The PESS consists of an 11.7-kWh lithium-ion battery with a unique hybrid inverter/converter rated for 6.0-kW discharge.

The PESS was configured as illustrated in Figure 3-196 and was used to demonstrate how consumers can use the PESS in conjunction with renewable solar generation and tiered TOU rates to reduce their overall electricity costs. This was accomplished by configuring the BESS to store solar electric energy generated during off peak times (typically 8 AM to 4 PM) and then discharge the stored renewable energy during times of peak usage and rates (typically 4 to 8 PM).

Figure 3-196: PESS Installation at SmartGrid Demonstration House



3.4.9.5.1.2 Expected Results

This technical demonstration was expected to yield the following:

- Typical daily charge/discharge load cycles for Renewable Energy Time Shift would be developed and demonstrated at the Demonstration House.
- The DC-DC Efficiency factor of the PESS for Renewable Time Shift would be determined. The system would be expected to operate at greater than 90% efficiency with respect to stored DC energy output versus solar DC energy input.
- The Energy Discharged for Renewable Energy Time-Shift factor for the PESS would be determined. The system would be expected to have approximately 10 kWh available daily for discharge.
- The charge/discharge load cycles developed would be mathematically applied to several typical load profiles to illustrate how a PESS system could be used with solar generation and TOU rates to lower the customer's energy cost.

3.4.9.5.1.3 Benefit Analysis Method/Factors

The DOE SGCT was used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits were quantified.

- Deferred Generation Capacity Investments
- Deferred Distribution Capacity Investments
- Reduced Electricity Costs
- Reduced CO_2 Emissions

Benefits were calculated using SGCT formulas. The following factors were measured, projected, or calculated during the application operation and/or demonstration.

Deferred Generation Capacity Investments

- Distributed Generation Use at Annual Peak Time (MW)
  (This benefit was included in the Distributed Production of Energy analysis.)
- Energy Storage Use at Annual Peak Time (MW)

Deferred Distribution Capacity Investments (Utility)

- Distribution Feeder Load Reduction (MW)
- Capital Carrying Charge of Distribution Upgrade ($)

Reduced Electricity Costs (Utility)

- Reduced Total Residential Electricity Cost ($)

Reduced CO_2 Emissions

- Annual Distributed Generation Production (MWh)
  (This benefit was included in the Distributed Production of Energy analysis.)

Additionally, the DOE ESCT was used to perform the benefit analysis for a customer owned PESS system. The following Stationary Energy Storage applications were combined in this analysis.

- Primary Application – Time-of-Use Energy Cost Management
- Secondary Application – Renewable Energy Time Shift
- Secondary Application – Electric Service Reliability

Primary Benefit for Renewable Energy Time Shift:

- Reduced Electricity Costs (Consumer)

3.4.9.5.1.4 Testing Methodology

The following points provide an overview of how the operational demonstration and testing for this application was accomplished:

- Customer solar photovoltaic panels were installed and connected to the PESS.
- Energy delivered to and received from the PESS was measured by the PESS Management System (PMS). All PESS data collected was stored in the PMS data archive.
- Energy delivered to and received from the customer's electrical system by the utility distribution grid was measured by the AMI net meter installed at the customer service entrance. All of the collected AMI data was stored in KCP&L's MDM and DMAT systems.
- A daily charge/discharge program was implemented to demonstrate and evaluate the benefit of using the PESS for solar generation time shift in conjunction with TOU rates. Charging occurred daily during Off-Peak rate times from available solar generation, and the energy was discharged during On-Peak rate times from 4 to 8 PM
- The PESS was operated with this as its standard mode over several months.

3.4.9.5.1.5 Analytical Methodology

The following points provide an overview of the analytical methods that were used to evaluate the impact and benefits of this application:

- Energy (DC watts) generated by the customer's solar photovoltaic panels system was measured and recorded in 1-minute intervals by the PESS SIS.
- Energy (DC watts) delivered to and received from the PESS battery was measured and recorded in 1-minute intervals by the by the PESS SIS.
- Energy (AC watts) delivered to and received from the customer's electrical system by the PESS was measured and recorded in 1-minute intervals by the by the PESS SIS.
- Energy (AC watts) delivered to the customer's emergency load panel by the PESS was measured and recorded in 1-minute intervals by the PESS SIS.
- The functionality of the PESS SIS was used to aggregate the 1-minute interval data to 15-minute interval data and was exported to Excel for analysis.
- AMI 15-minute interval solar generation data from the project's grid-connected solar installations was extracted from the MDM System through KCP&L's DMAT and used as a solar generation baseline.
- An annual solar generation profile for the PESS was constructed using the solar generation baseline data to fill in any missing data caused by Demonstration House activities and other project operational testing.
- Multiple energy shift cycles were analyzed to determine the potential maximum solar energy that could be stored and the efficiency of the battery charge/discharge cycle.
- The Daily Round Trip Efficiency of the PESS battery was calculated as [Daily Energy (DC watts) Delivered by the battery to the PESS inverter] / [Daily Energy (DC watts) Received from the Solar Panels].
- An annual daily Shifted Renewable Energy profile for the PESS was constructed using the using the solar generation profile and daily Round Trip Efficiency of the PESS battery.
- The Daily Unshifted Renewable Energy was calculated as [Daily Shifted Energy]/[Daily Round Trip Efficiency of the PESS battery]. The Unshifted Renewable Energy is the renewable energy that would have been delivered to the customer electric system if it had not been diverted to the battery.

- The Annual PESS Shifted and Unshifted Renewable Energy (kWh) was calculated from the daily energy profiles.
- The Annual Reduced Customer Electricity Cost was calculated by the Smart Grid Computational Tool and Energy Storage Computational Tool, and expressed in subsequent sections.

3.4.9.5.2 Plan Execution and Analysis

The following sections provide details regarding the functional tests performed, data collection, and analysis performed for the Renewable Energy Time Shift operational test.

3.4.9.5.2.1 Baseline Solar Generation Profile for PESS Analysis

To aid in determining the potential of a PESS to provide Renewable Energy Time Shift reductions, the project team constructed the solar generation profile for the Demonstration House using the composite per-unit solar generation load profile developed as part of the Distributed Rooftop Solar Generation function analysis.

Figure 3-197: Demonstration House Monthly Solar Energy Production

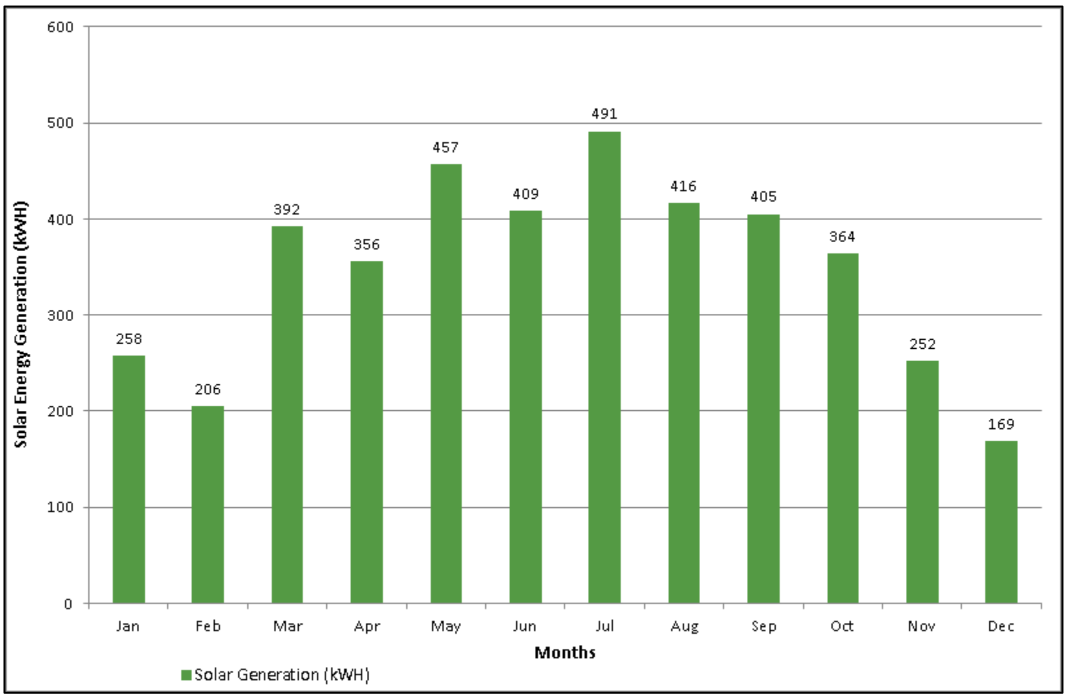
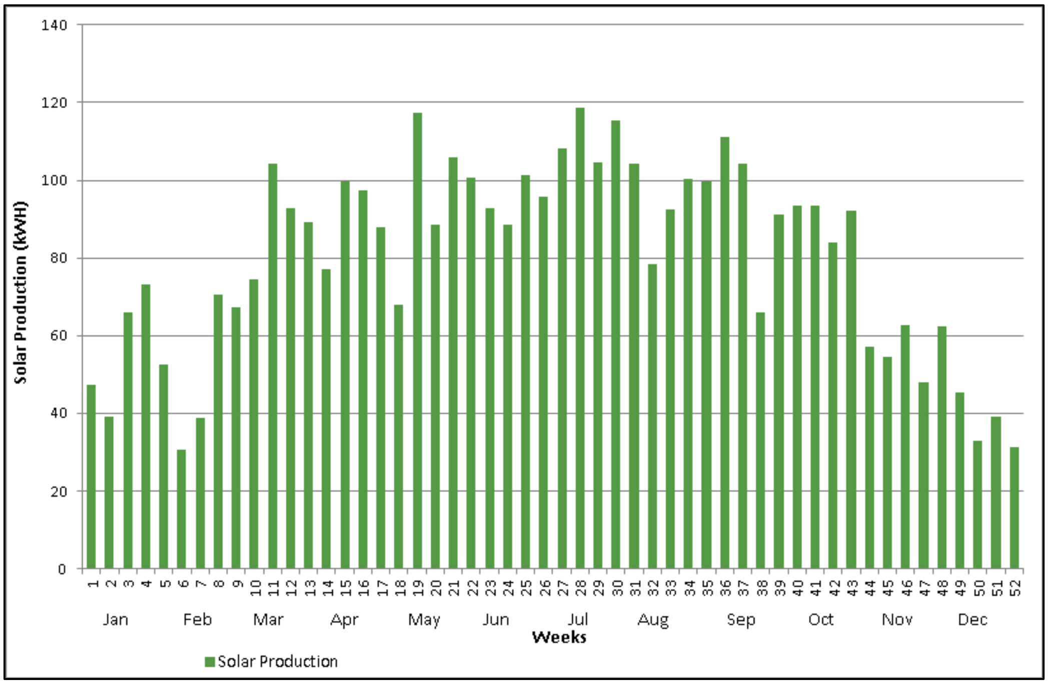
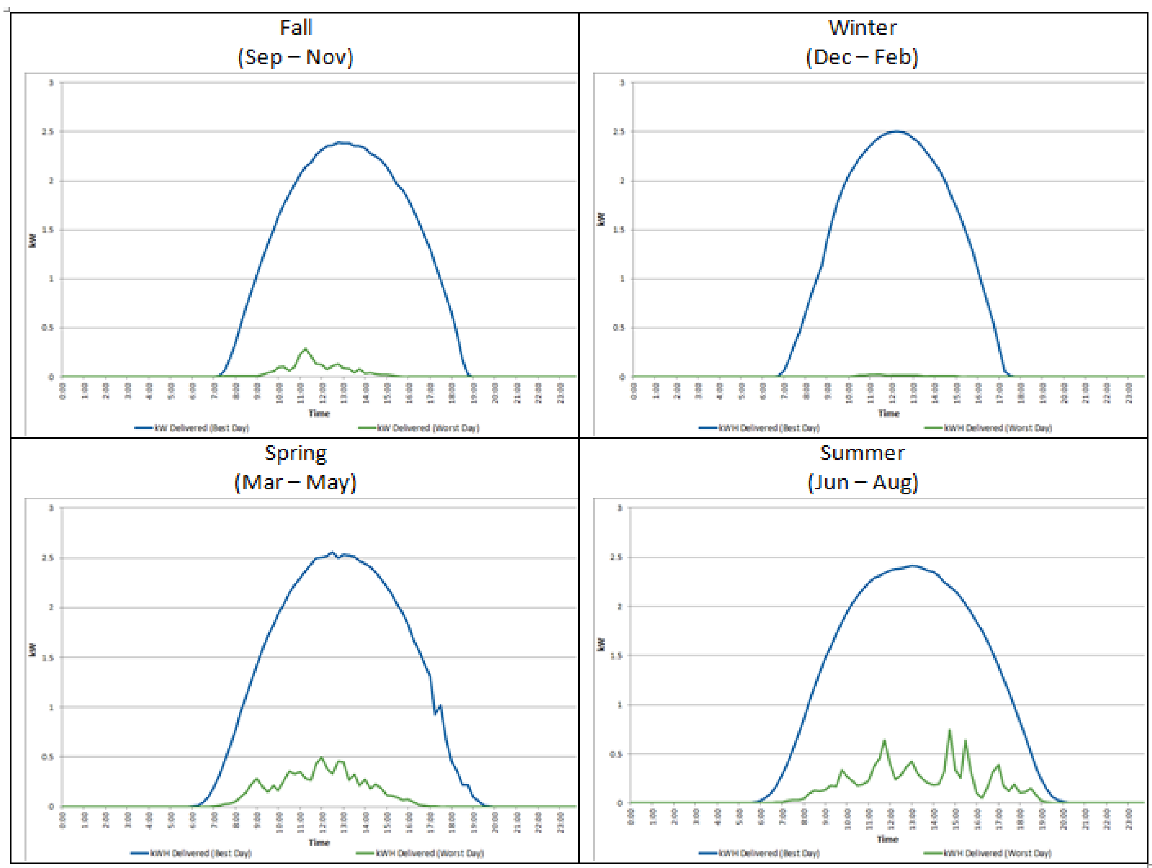


Figure 3-198: Demonstration House Weekly Solar Energy Production



The following figure provides illustrations of the composite PV production load profiles for the best and worst solar production days by season.

Figure 3-199: Demonstration House Solar kW – Typical Day



3.4.9.5.2.2 Daily Charge and Discharge Operation

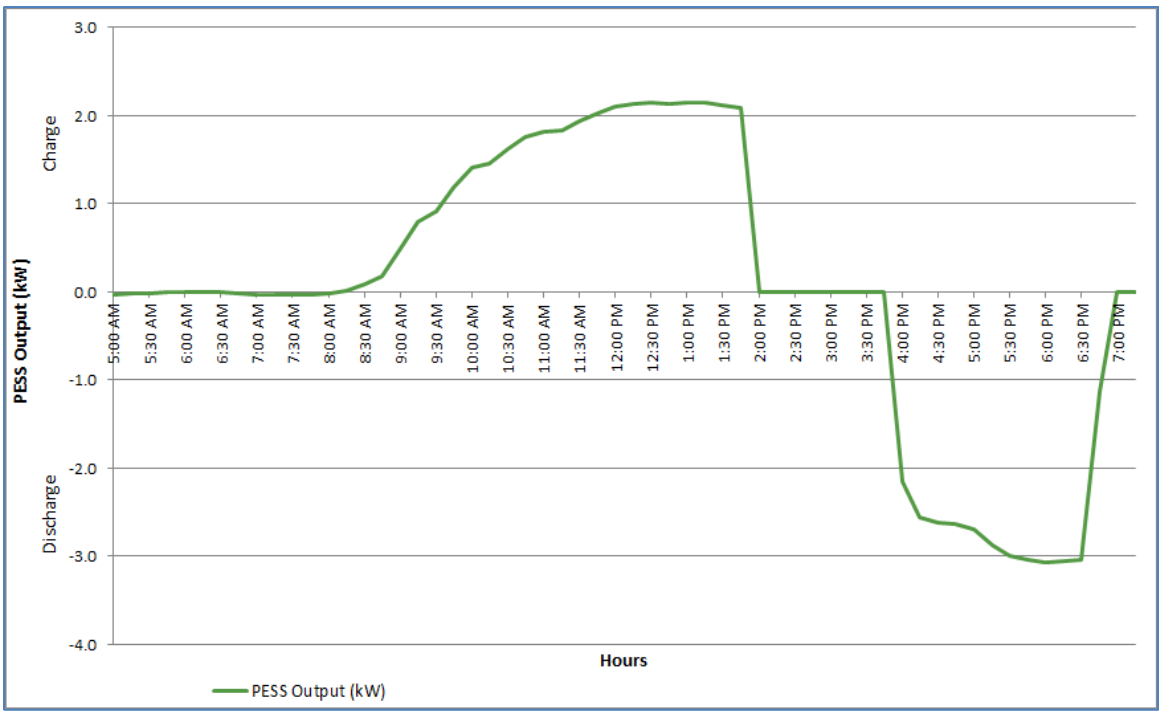
The manufacturer's operation manual recommends that the battery should not be routinely charged above 95% or discharged below 10% charge level to protect the battery and maintain its useful life. It also recommends reserving 10% battery capacity for UPS mode. These operational constraints limit the operational output of the 11.7-kWh lithium polymer battery for routine application use to 8.75 kWh.

The PESS was set to charge daily from the solar generation from 6 AM to 4 PM and discharge from 4 PM to 8 PM local time. Due to solar panel and roof replacement constraints, the daily operation for the demonstration could not be conducted until late July. To increase the likelihood that the solar generation could fully charge the battery, the project team set the 4 hour On-Peak period as 4-8 PM for this analysis. For the demonstration the PESS SMS was configured with the following settings:

- The SIS charge rate was set at 66% of inverter capacity, or 3.96 kW, to provide a full charge, up to 11.7 kWh, during the 3-hour charge period.
- The SIS discharge (or deliver to main service panel) rate was set at 45% of inverter capacity, or 2.7 kW, to deliver approximately 9 kWh during the 4-hour discharge period.

Figure 3-200 shows a representative 15-minute interval daily charge and discharge cycles for renewable Energy Time Shift under these settings. Note that the battery discharge rate is not constant over the discharge time as part of the PESS discharge energy is supplied by the solar generation.

Figure 3-200: PESS Daily Renewable Time Shift Charge and Discharge Profile



3.4.9.5.2.3 Efficiency of PESS Battery for Renewable Energy Time Shift

At the beginning of the project, it was expected that the PESS would operate for Renewable Energy Time Shift with efficiency greater than 90% with respect to DC energy output versus solar DC energy input. The SIS records the DC energy received from the solar panels and DC energy discharged from the battery modules. The purpose of this analysis is to verify the DC-DC efficiency of PESS for Renewable Energy Time Shift analysis.

Based on the daily charge and discharge cycle, the DC-DC Efficiency of the PESS is calculated as:

$$DC - DC\ Effecinecyof\ PESS = \frac{DC\ energy\ discharged\ from\ PESS\ battery}{DC\ energy\ recieved\ by\ PESS\ battery\ from\ solar\ panels} \times 100\%$$

Table 3-141 shows the DC energy delivered by the solar panels to charge the PESS battery, the DC energy discharged from the PESS battery, and DC-DC Efficiency of PESS battery. These values were measured over many days. The daily DC-DC efficiency varied from 89.9% to 98.7%, with average efficiency of 93.6%.

Table 3-141: Daily DC-DC Efficiency of the PESS

Date	PV-Battery In (kWh-DC)	Battery Out (kWh-DC)	DC-DC Efficiency
09/04/2014	8.41	7.91	94.0%
09/07/2014	8.81	7.98	90.6%
09/25/2014	8.36	8.26	98.7%
09/27/2014	9.02	8.11	89.9%
09/29/2014	8.69	8.44	97.1%
09/30/2014	8.78	8.50	96.8%
10/08/2014	8.59	7.94	92.4%
10/18/2014	8.34	7.85	94.2%
10/24/2014	8.81	8.18	92.9%
10/29/2014	8.94	8.09	90.6%
11/05/2014	8.29	7.80	94.1%
11/08/2014	8.52	7.92	92.9%
11/09/2014	8.25	8.02	97.2%
11/10/2014	8.51	7.98	93.9%
11/12/2014	8.18	7.51	91.8%
11/25/2014	8.23	7.68	93.3%
11/29/2014	8.03	7.43	92.6%
Average All Samples	**8.49**	**7.98**	**93.6%**

3.4.9.5.2.4 Potential Utility System and Distribution Peak Reduction

The PESS can be operated in multiple ways to effect utility capacity requirements. First, the customer could participate in a utility Demand Response program or allow the utility to dispatch the PESS for Demand Response. For Demand Response the PESS could potentially supply 6 kW (inverter capacity) for an event lasting 1 hour, 4.3 kW for an event lasting 2 hours, or 2.15 kW for an event lasting 4 hours.

Secondly, under the assumption that the utility's system and distribution peaks occur during the On-Peak TOU billing period, the utility would experience a demand reduction when the customer discharged the battery for Renewable Energy Time Shift. For this operational test an On-Peak billing period of 4 hours was assumed, corresponding with the experimental SmartGrid TOU rate implemented for the project.

During the daily charge/discharge cycle, the PESS battery discharged at a rate of varying from 2 kW to 3 kW, and did not discharge for a full 4 hours. Upon further investigation it became clear that the discharge rate (or deliver to the grid) was net of the critical load panel loads, solar generation, and battery discharge. Table 3-141 shows that the average discharge was 7.98 kWh, which, if the settings were tuned further, could deliver 2 kW of customer and utility load reduction for a 4-hour duration.

3.4.9.5.2.5 Customer Energy Usage with PESS Used for Renewable Energy Time Shift

The SmartGrid Demonstration house electrical usage is not representative of a typical residential customer. Therefore, a typical residential customer was selected to analyze customer benefits of the PESS when used for Renewable Energy Time Shift. The customer selected has an annual usage of 10,319 KW, approximately 15% more than the average Demonstration Area residential customer (~8,800 kWh).

A daily load profile of the selected representative residential customer from the SmartGrid Demonstration area in is shown in Figure 3-201. While no two customers have identical usage patterns, this customer displays a typical daily pattern: minimal usage during the late night, a sharp rise to moderate usage in the early morning hours, then by a midmorning drop in usage that begins to increase throughout the day, with significant peak usage during the On-Peak period, and then slightly reduced but sustained moderate usage until midnight.

Figure 3-201 also shows the impact a solar PV system similar to the one installed at the Demonstration House would have on this customers' daily load profile.

Figure 3-202 shows the weekly kWh usage of this residential customer throughout the year in four usage groupings: Late Night, Off-Peak (Day), Off-Peak (Evening), and On-Peak.

Figure 3-203 shows the impact on this customers' daily load profile with the PESS operated for Renewable Energy Time Shift.

Figure 3-204 shows the weekly kWh usage of this residential customer throughout the year in four usage groupings: Late Night, Off-Peak (Day), Off-Peak (Evening), and On-Peak.

Figure 3-201: Summer Typical Residential Customer Daily Load Profile with PV

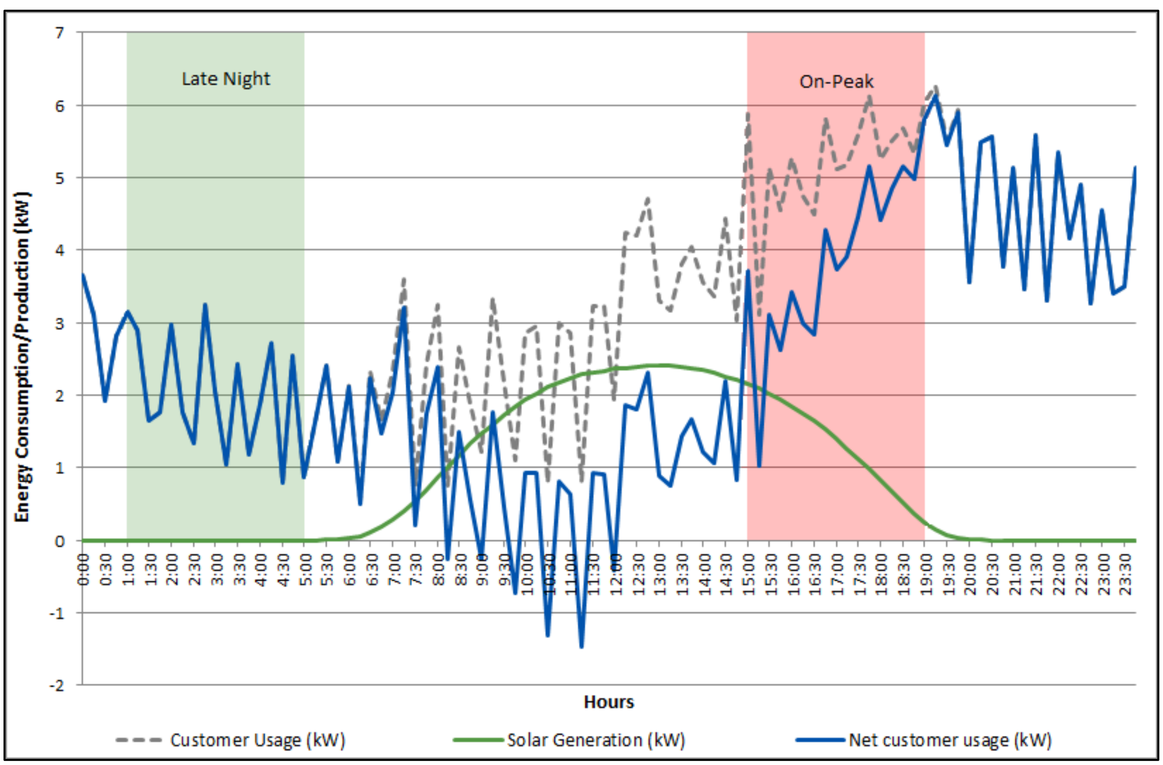


Figure 3-202: Weekly Typical Residential Customer Usage with PV

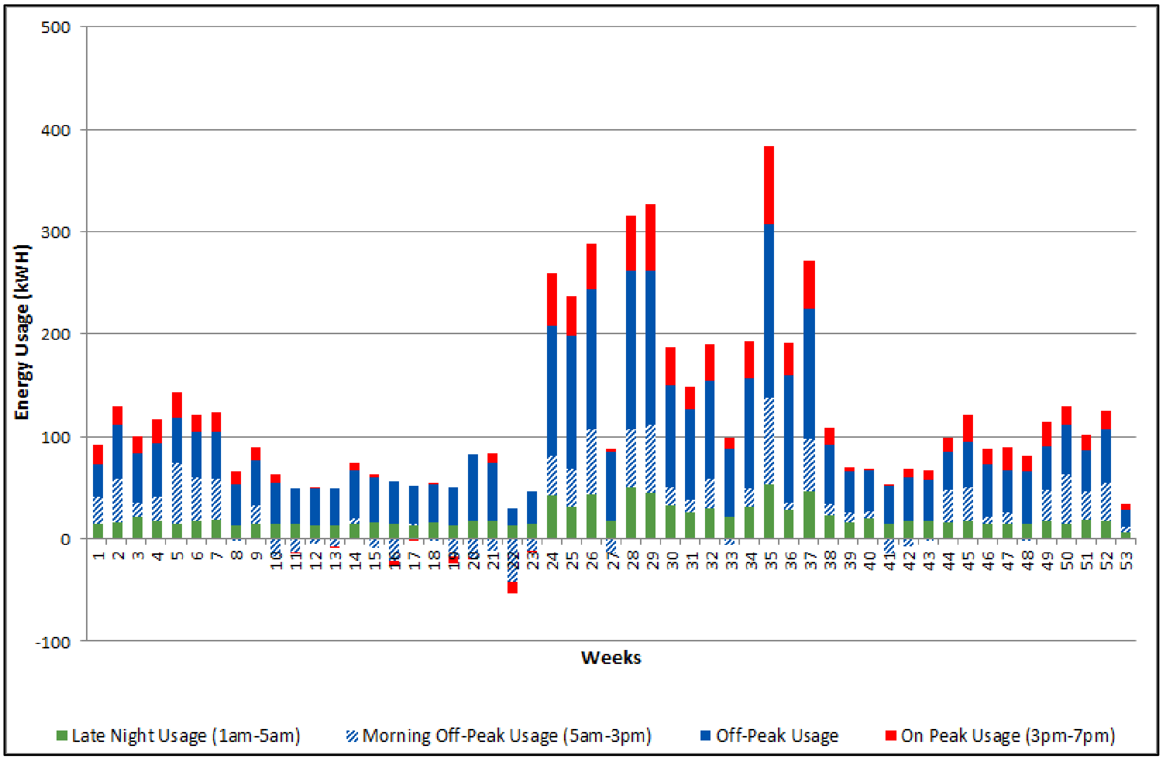


Figure 3-203: Summer Typical Customer Daily Load Profile with PV & PESS

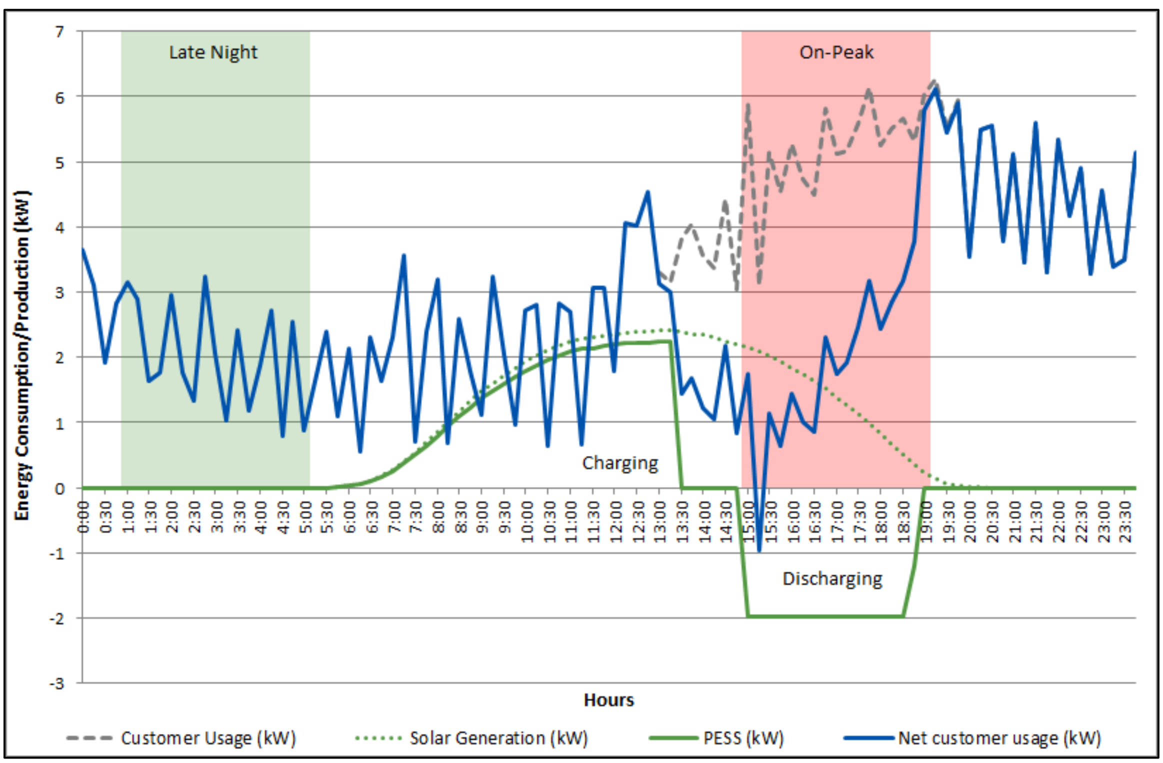


Figure 3-204: Weekly Typical Residential Customer Usage with PV & PESS

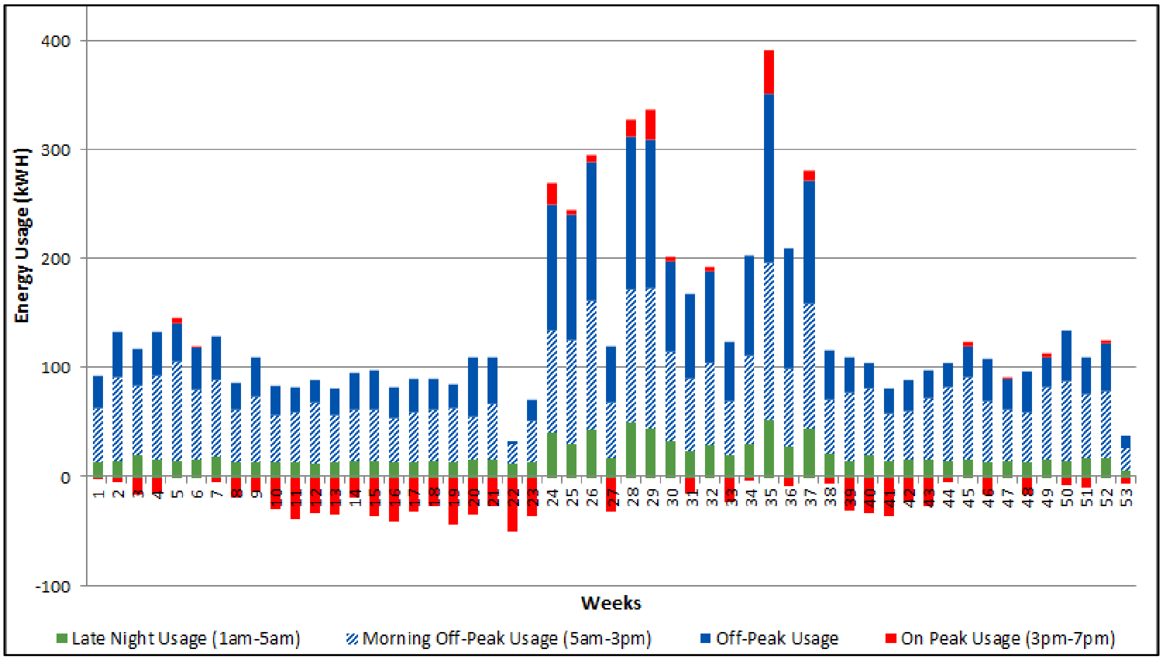


Table 3-142 below summarizes the impact of PV and the PESS on the On-Peak, Off-Peak (Day), Off-Peak (Evening), and Late Night energy usage for this residential customer by season. In this table the PESS has been operated in Renewable Energy Time Shift mode to maximize the offset of the customer's On-Peak usage by discharging all stored renewable energy during the On-Peak period.

Table 3-142: Residential Customer Usage per Season with PESS Renewable Time Shift

	Customer Energy Usage Metrics (kWh)	Summer (Jun 16 - Sep 15)	Fall (Sep 16 - Dec 15)	Winter (Dec 16 - Mar 15)	Spring (Mar 16 - Jun 15)	Annual Total
Usage Before PV	On Peak Grid Energy (3-7 PM M-F)	757	282	275	280	1,594
	Off Peak Grid Energy (5 AM-3 PM)	1,396	888	942	799	4,025
	Off Peak Grid Energy (7 PM-1 AM)	1,644	626	599	712	3,581
	Late Night Energy (1-5 AM)	459	219	217	223	1,117
	Total Energy	4,257	2,015	2,033	2,013	10,318
Usage with PV	On Peak Grid Energy (3-7 PM M-F)	501	172	208	45	926
	Off Peak Grid Energy (5 AM-3 PM)	428	166	305	-96	803
	Off Peak Grid Energy (7 PM-1 AM)	1,525	575	577	620	3,297
	Late Night Energy (1-5 AM)	459	219	217	223	1,117
	Total Energy	2,914	1,132	1,306	791	6,143
Usage with PV & PESS	On Peak Grid Energy (3-7 PM M-F)	35	-181	-139	-378	-662
	Off Peak Grid Energy (5 AM-3 PM)	1,203	743	814	620	3,380
	Off Peak Grid Energy (7 PM-1 AM)	1,337	408	455	456	2,657
	Late Night Energy (1-5 AM)	459	219	217	223	1,117
	Total Energy	3,034	1,189	1,347	921	6,492

3.4.9.5.2.6 Customer Cost Savings Potential with PESS Used for Renewable Energy Time Shift

As was discussed in the Time-of-Use Energy Cost Management analysis, to combine cost of electricity savings from both the Time-of-Use Energy Cost Management and Renewable Energy Time Shift requires a three-tier TOU rate. KCP&L could not implement a three-tier TOU rate for the SGDP due to limitation in the utility's CIS billing system. But to support this analysis, the project team developed a hypothetical year-round three-tier TOU structure that would be revenue neutral with the two-tier TOU rate implemented by the project. The hypothetical TOU rate used for this analysis was based on the following parameters:

- Summer Effective Dates – June 15 - Sept. 15
- On-Peak Times – 3-7 PM, Monday-Friday (excluding holidays)
- Late Night Times – 1 -5 AM
- Off-Peak Times – All other times
- On-Peak Rate: $0.336 (summer); $0.225 (winter)
- Off-Peak Rate: $0.09 (summer); $0.075 (winter)
- Late Night Rate: $0.03 (summer); $0.025 (winter)

This hypothetical rate was used to illustrate the potential customer savings for installing solar generation and a PESS used for Renewable Energy Time shift.

<u>Annual Energy Cost without PV or PESS</u>
Based on these TOU program parameters and the usage presented in Table 3-142 this customer's annual cost of electricity without PV or PESS would be $1,076.95, calculated as follows:

Summer On-Peak Cost ($) = $0.336/kWh x 757 kWh = $242.352
Summer Off-Peak Cost ($) = $0.09/kWh x [1,396 kWh + 1,644 kWh] = $273.600
Summer Late Night Cost ($) = $0.03/kWh x 459 kWh = $13.77
Winter On-Peak Cost ($) = $0.225/kWh x [1,594 kWh – 757kWh] = $188.325
Winter Off-Peak Cost ($) = $0.075/kWh x [4,025 kWh + 3,581 kWh – 1,396 kWh – 1,644 kWh] = $342.45
Winter Late Night = Cost ($) $0.025/kWh x [1,117 kWh – 459kWh] = $16.45
Total Annual Residential Cost of Electricity ($) = $1,076.95

<u>Annual Energy Cost with PV but without PESS</u>
Based on these TOU program parameters and the usage presented in Table 3-142 this customer's annual cost of electricity without PV or PESS would be $1,076.95, calculated as follows:

Summer On-Peak Cost ($) = $0.336/kWh x 501 kWh = $168.336
Summer Off-Peak Cost ($) = $0.09/kWh x [428 kWh + 1,525 kWh] = $175.77
Summer Late Night Cost ($) = $0.03/kWh x 459 kWh = $13.77
Winter On-Peak Cost ($) = $0.225/kWh x [926 kWh – 501 kWh] = $95.625
Winter Off-Peak Cost ($) = $0.075/kWh x [803 kWh + 3,297 kWh – 428 kWh – 1,525 kWh] = $161.025
Winter Late Night = Cost ($) $0.025/kWh x [1,117 kWh – 459kWh] = $16.45
Total Annual Residential Cost of Electricity ($) = $630.98

<u>Annual Energy Cost with PV and PESS</u>
Based on these TOU program parameters and the usage presented in Table 3-142 this customer's annual cost of electricity with PV and PESS would be $376.03, calculated as follows:

Summer On-Peak Cost ($) = $0.336/kWh x 35 kWh = $11.76
Summer Off-Peak Cost ($) = $0.09/kWh x [1,203 kWh + 1,337 kWh] = $228.60
Summer Late Night Cost ($) = $0.03/kWh x 459 kWh = $13.77
Winter On-Peak Cost ($) = $0.225/kWh x [-662 kWh – 35kWh] = $-156.825
Winter Off-Peak Cost ($) = $0.075/kWh x [3,380 kWh + 2,657 kWh – 1,203 kWh – 1,337 kWh] = $262.275
Winter Late Night = Cost ($) $0.025/kWh x [1,117 kWh – 459kWH] = $16.45
Total Annual Residential Cost of Electricity ($) = $376.03

Based on this hypothetical rate, customer could potentially save $446 (41% savings) annually by installing the 2.82 kW of solar PV generation and save an additional $255 (40% additional savings) annually by investing in a PESS and implementing the Renewable Energy Time Shift function.

These calculations are theoretical and are provided solely to illustrate the potential order of magnitude for electricity cost savings that these functions might provide. Cost savings a customer could actually achieve would be dependent on the specific TOU and net metering tariffs under which it was implemented.

3.4.9.5.2.7 Customer Energy Usage with PESS Used with Renewable Energy and TOU

Analysis in previous sections has covered the customer usage and the cost savings impact of operating the PESS in conjunction with solar generation and the Renewable Energy Time Shift. In this section the analysis covers the customer usage and cost savings impact of operating the PESS in conjunction with solar generation using the Time-of-Use Energy Cost Function. Under this scenario the PESS would be configured to operate as follows during each of the TOU rate time periods:

- Off-Peak (Day) – Solar PV would offset any customer consumption.
- On-Peak – Solar PV would offset any customer consumption.
- On-Peak – PESS would be fully discharge the battery to offset consumption.
- Off-Peak (Evening) – Solar PV would offset any customer consumption.
- Late Night – The PESS would fully charge the battery.

For this analysis, no load-leveling operation that the PESS could perform was depicted; as such operation would slightly increase the customer's kWh consumption due to PESS efficiency losses and not provide any additional cost savings. If the TOU tariff included a demand component, the PESS could operate in load-leveling mode to lower the kW demand and achieve additional cost savings.

Figure 3-205 shows the impact on this customer's daily load profile with the PESS operated for Renewable Energy Time Shift and Time-of-Use Energy Cost Management.

Figure 3-205: Summer Typical Daily Load Profile with TOU & RETS

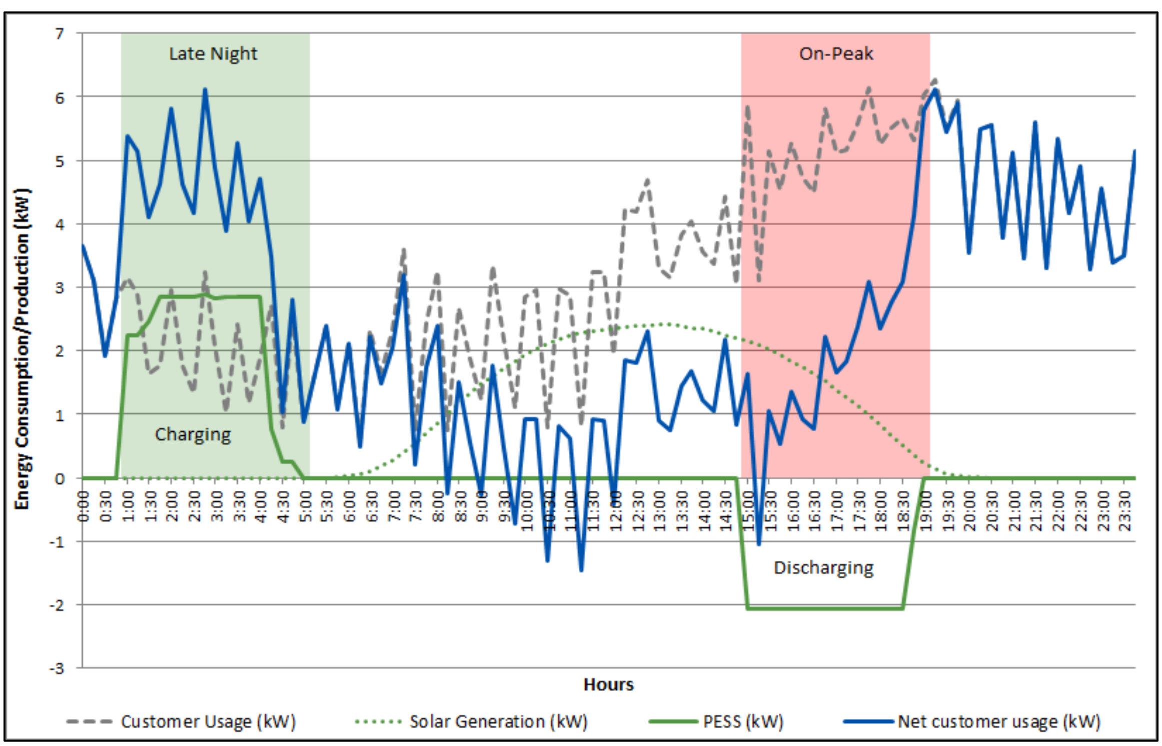


Figure 3-206 shows the weekly kWh usage of this residential customer throughout the year in four usage groupings; Late Night, Off-Peak (Day), Off-Peak (Evening), and On-Peak.

Figure 3-206: Weekly Typical Customer Usage with TOU & RETS

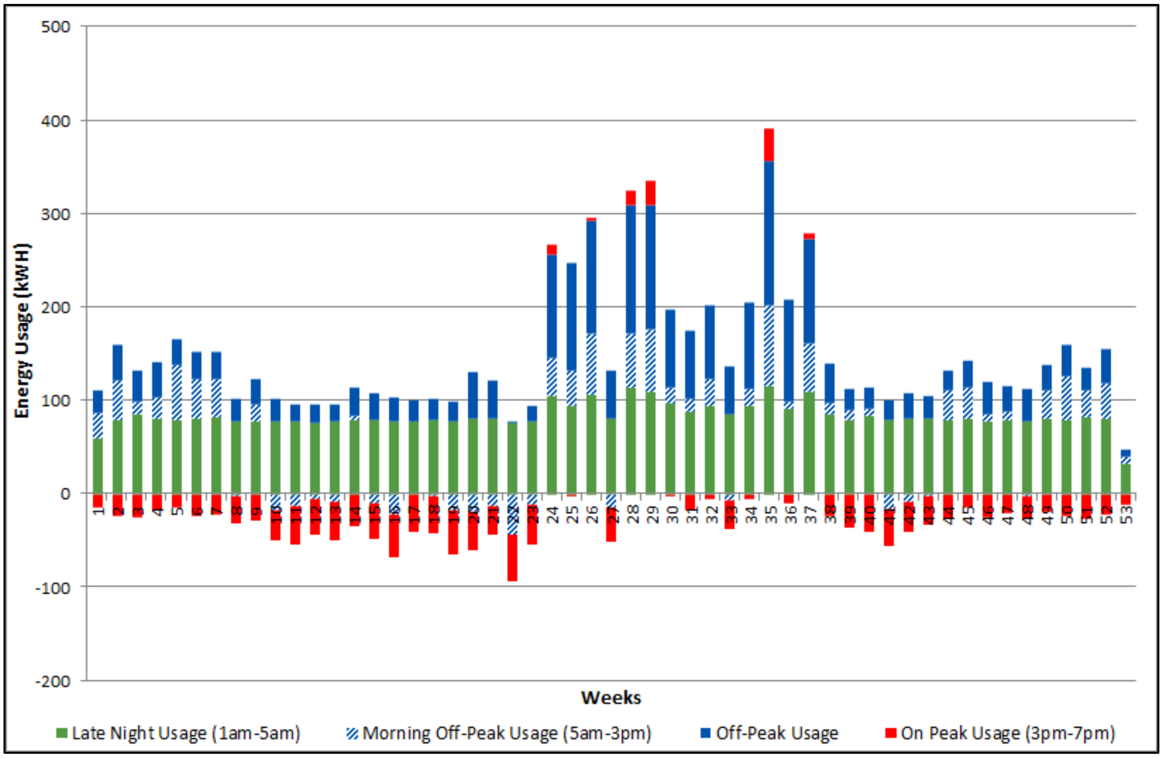


Table 3-143 summarizes the impact of both PESS functions on the On-Peak, Off-Peak (Day), Off-Peak (Evening), and Late Night energy usage for this residential customer by season. In this table the PESS has been operated to maximize the offset of the customer's on-peak usage by discharging all stored renewable energy during the On-Peak period.

This hypothetical rate presented earlier was used to illustrate the potential customer savings for installing solar generation and a PESS used for Renewable Energy Time shift and Time-of-Use Energy Cost Management.

Annual Electric Cost Under Three-Tier TOU with PV and PESS

Based on these TOU program parameters and the usage presented in Table 3-143 this customer's annual cost of electricity with PV and PESS used with the Time-of-Use Energy Cost Management function would be calculated as follows:

Summer On-Peak Cost ($) = $0.336/kWh x -233 kWh = $ - 78.29
Summer Off-Peak Cost ($) = $0.09/kWh x 1,953 kWh = $ 175.77
Summer Late Night Cost ($) = $0.03/kWh x 1,303 kWh = $ 39.09
Winter On-Peak Cost ($) = $0.225/kWh x -1,753 kWh = $ - 394.43
Winter Off-Peak Cost ($) = $0.075/kWh x 2,147 kWh = $ 161.03
Winter Late Night = Cost ($) $0.025/kWh x 3,162 kWh] = $ 79.05
Total Annual Residential Cost of Electricity ($) = $ - 17.78

Annually the customer would generate net bill credit of $ 17.78 with the utility if the net metering tariff credits the customer with the full retail rate for any energy delivered back to the utility.

Table 3-143: Residential Customer Usage per Season with TOU & RETS

	Customer Energy Usage Metrics (kWh)	Summer (Jun 16 - Sep 15)	Fall (Sep 16 - Dec 15)	Winter (Dec 16 - Mar 15)	Spring (Mar 16 - Jun 15)	Annual Total
Usage Before PV	On Peak Grid Energy (3-7 PM M-F)	757	282	275	280	1,594
	Off Peak Grid Energy (5 AM-3 PM)	1,396	888	942	799	4,025
	Off Peak Grid Energy (7 PM-1 AM)	1,644	626	599	712	3,581
	Late Night Energy (1-5 AM)	459	219	217	223	1,117
	Total Energy	4,257	2,015	2,033	2,013	10,318
Usage with PV	On Peak Grid Energy (3-7 PM M-F)	501	172	208	45	926
	Off Peak Grid Energy (5 AM-3 PM)	428	166	305	-96	803
	Off Peak Grid Energy (7 PM-1 AM)	1,525	575	577	620	3,297
	Late Night Energy (1-5 AM)	459	219	217	223	1,117
	Total Energy	2,914	1,132	1,306	791	6,143
	PESS Charge Energy	844	834	825	844	3,347
	PESS Discharged Energy	734	726	718	734	2,913
Usage with PV & PESS	On Peak Grid Energy (3-7 PM M-F)	-233	-554	-510	-689	-1,986
	Off Peak Grid Energy (5 AM-3 PM)	428	166	305	-96	803
	Off Peak Grid Energy (7 PM-1 AM)	1,525	575	577	620	3,297
	Late Night Energy (1-5 AM)	1,303	1,053	1,042	1,067	4,465
	Total Energy	3,023	1,240	1,414	902	6,579

3.4.9.5.2.8 Issues and Corrective Actions

The following issues and corrective action were encountered during the performance of the Renewable Energy Time Shift operational testing and analysis.

Table 3-144: Issues and Corrective Actions

Issue	Corrective Action
• Original solar panels were not compatible with the Sunverge PESS.	• Replaced the solar panels with compatible panels.
• The SmartGrid Demonstration House electrical usage is not representative of a typical residential customer	• The annual load profile of a "typical" residential customer was used for this analysis.
• Due to technical solar integration issues, roof replacement and conflicting demonstrations at the Demonstration House, annual data collection for this test was not able to be collected.	• Used the per-unit solar generation profile developed in the Distributed Rooftop Solar Generation operational test. • Modeled daily PESS charge/discharge patterns and applied them to the load profile of the typical residential customer.
• KCP&L did not have a three-tier TOU rate to evaluate Off-Peak reduction scenarios	• Developed a hypothetical three-tier TOU rate that was revenue neutral for this analysis.

3.4.9.5.3 Findings

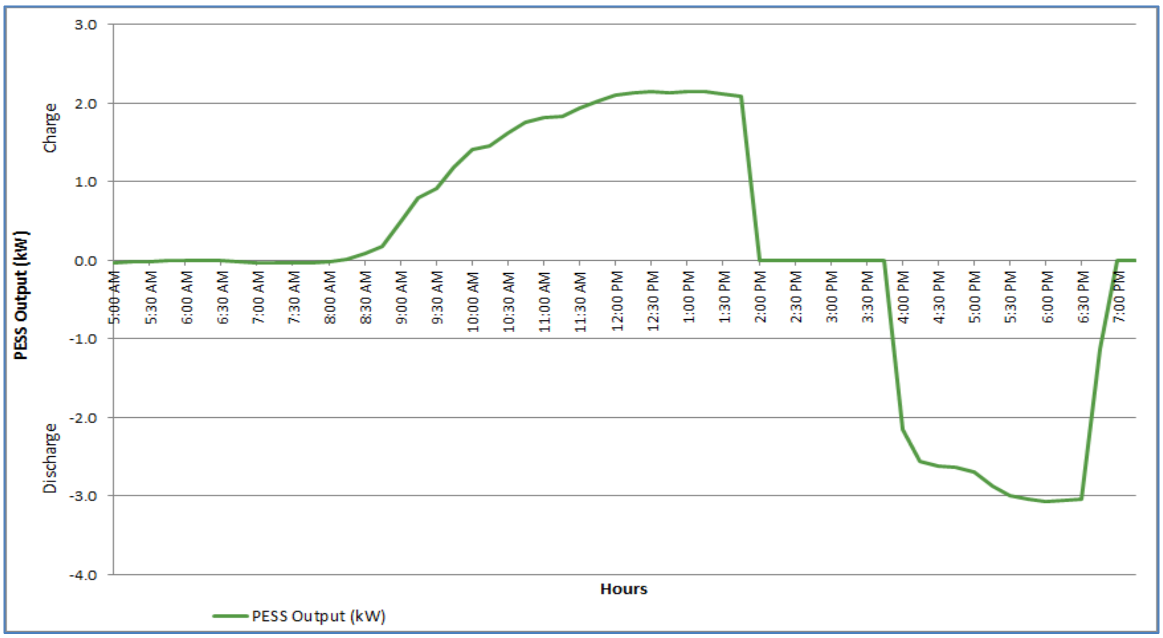
The results obtained in the execution and analyses of Renewable Energy Time Shift operational testing are summarized in the sections below.

3.4.9.5.3.1 Discussion

The PESS installed at the Demonstration House is a 11.7-kWh lithium-ion battery with a unique hybrid 6.0-kW inverter/converter, a battery set to charge and discharge daily from the grid. Due to limitations of the Demonstration House and other project constraints, the majority of this operational demonstration analysis was conducted using constructed data models constructed from project data.

The DC-DC efficiency of the PESS was measured and calculated over many days of operation. Figure 3-207 illustrates a typical PESS charge/discharge cycle used for renewable energy time shift. The average DC-DC efficiency was calculated to be 93.6%, higher than the expected efficiency of 90%.

Figure 3-207: PESS Daily Renewable Time Shift Charge and Discharge Profile

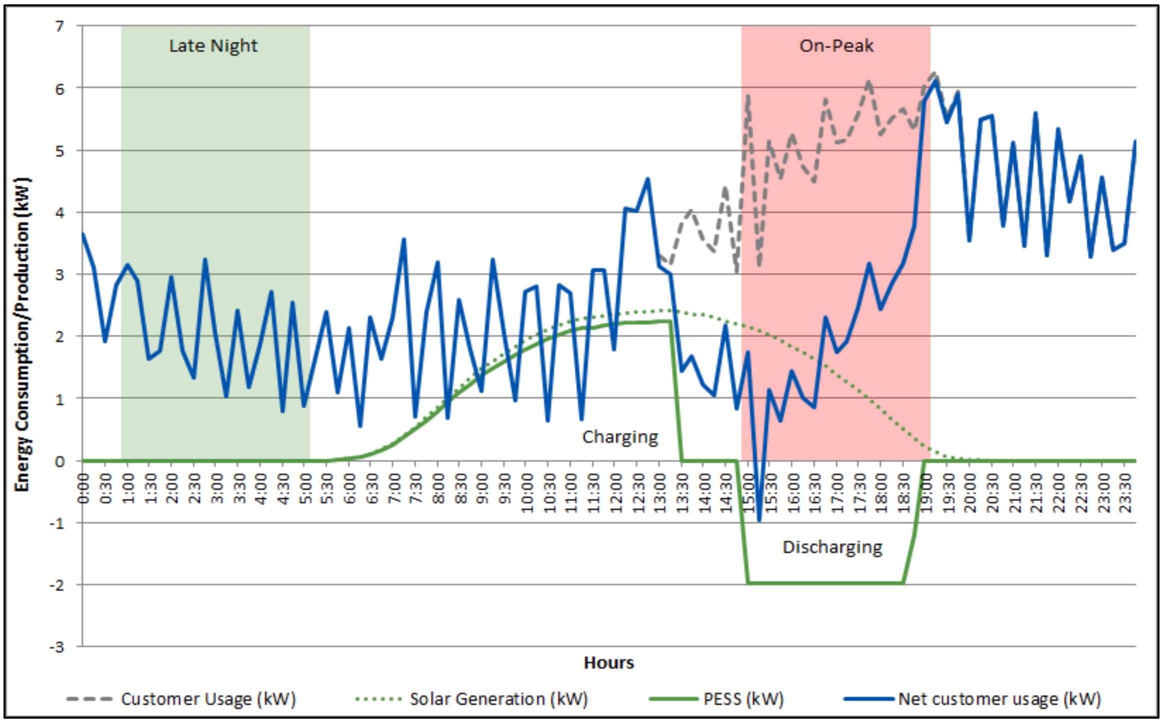


The SmartGrid Demonstration House electrical usage is not representative of a typical residential customer. Therefore, a typical residential customer, with annual usage of 10,319 kWh, was selected for analysis of customer benefits of the PESS when used for renewable energy time shift. The 2.82-kW solar PV system produced 4,175 kWh of renewable energy, of which only 668 kWh was produced during the 3-7 PM On-Peak time period.

The PESS energy charge/discharge cycles were then mathematically applied to this customer's usage and analyzed for cost savings. Figure 3-208 illustrates the effect on the customer's load profile when the PESS was charged from 6 AM to 3 PM from the solar generation and discharged from 3 PM to 7 PM to offset On-Peak usage. The analysis showed that the PESS shifted 1,588 kWh of solar energy produced Off-Peak to the On-Peak time period, creating an On-Peak negative consumption of 662 kWh annually.

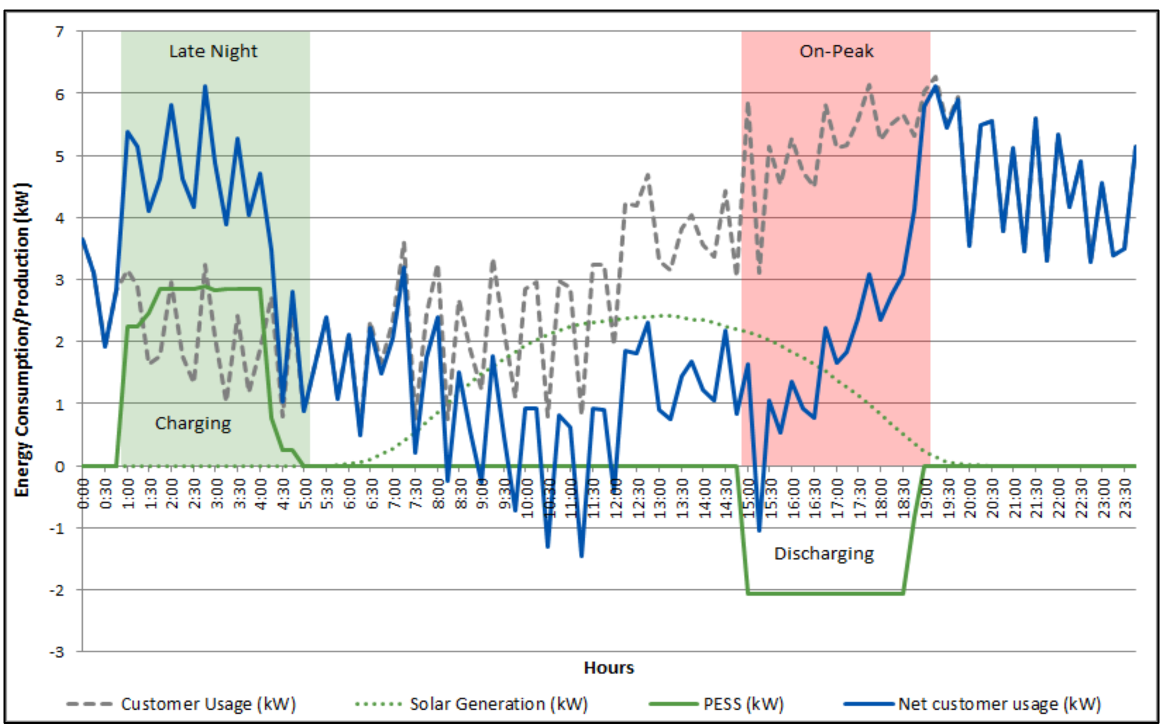
When analyzed in conjunction with the parameters of hypothetical three-tier TOU rate, this customer's annual cost of electricity before adding the solar generation or PESS would have been $1,077. By installing the 2.82 kW of solar PV generation, the customer's annual cost of electricity dropped to $631, a savings of $446 or 41%. Investing in a PESS and implementing the Renewable Energy Time Shift function would create an additional $255 in savings, reducing the annual cost of electricity to $376.

Figure 3-208: Summer Typical Customer Daily Load Profile with PV & PESS



Further analysis was performed to quantify the customer usage and cost savings effect of operating the PESS in conjunction with solar generation the Time-of-Use Energy Cost Function as illustrated in Figure 3-209 below.

Figure 3-209: Summer Typical Daily Load Profile with TOU & RETS



Based on the hypothetical three-tier TOU program, this customer's annual cost of electricity — with PV and PESS used with the Time-of-Use Energy Cost Management function — would be reduced by $1,095 and would generate an annual net bill credit of nearly $18 with the utility if the net metering tariff credits the customer with the full retail rate for any energy delivered back to the utility.

3.4.9.5.3.2 Expectations vs. Actuals

The following table provides a comparison of the Expected Results and the Actual Outcomes for the Renewable Energy Time Shift operational test.

Table 3-145: Expected Results vs. Actual Outcome

Expected Results	Actual Outcome
• Typical daily charge/discharge load cycles Renewable Energy Time Shift will be developed and demonstrated	• Daily charge/discharge operations for Renewable Energy Time Shift were developed and demonstrated.
• The DC-DC Efficiency factor of the PESS will be determined. Expected to be greater than 90%.	• The DC-DC Efficiency factor for the PESS was determined to be 93.6%.
• The dischargeable Energy for Renewable Energy Time-Shift for the PESS will be determined. The system will be expected to have approximately 10 kWh available daily for discharge.	• With vendor operating guidelines and a 10% reservation for UPS mode (Electric Service Reliability) the 11.7-kWh PESS had 8.75 kWh available for routine application use.
• The charge/discharge cycles developed will be mathematically applied to a typical residential customer load profile to illustrate how a PESS system could be used with TOU rates to lower the customers energy cost.	• The Renewable Energy Time Shift charge/discharge cycles were applied to a typical customer load profile and analyzed to show the potential for cost savings with TOU rates.

3.4.9.5.3.3 Computational Tool Factors

The following table lists the values derived from the Renewable Energy Time Shift operational test analysis for use as inputs to the Energy Storage Computational Tool.

Table 3-146: Computational Tool Value

Name	Description	Calculated Value
Total Renewable Energy Discharged for Energy Time Shift	Total amount of renewable energy discharged for the purpose of shifting energy from an Off-Peak time to an On-Peak time	0 MWh

- Total Renewable Energy Discharged for Energy Time Shift (MWh) – For the SGCT analysis greater economic benefits can be achieved with the TOU Energy Cost Management function in conjunction with a 3-tier tariff. Therefore, there will be no renewable energy discharged for energy time shift.

3.4.9.5.4 Lessons Learned

Throughout the conduct of the operational testing and analysis of the PESS for the Renewable Energy Time Shift function, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- Learned that manufacturer's recommendation that the battery should not be routinely charged above 95% and discharged below 10% charge level to protect the battery and maintain its useful life. This limitation must be factored in when sizing the battery storage component for any PESS.
- Differential in TOU rates needs to be at least 16% for there to be any savings to be experienced by the customer. KCP&L's SmartGrid TOU rate was a two-tier rate structure limited to four summer months. A PESS could achieve greater savings from Renewable Energy Time Shift for the customer with year-round TOU rates. The PESS benefits could be further maximized when operated in conjunction with Time-of-Use Energy Cost Management function in conjunction with year-round three-tier TOU Rates.
- The PESS demonstrated it has considerable flexibility in how it can be applied to provide maximum customer benefits, but it must be tailored to the specific customer load profile and rate structure.

3.4.9.6 Electric Service Reliability

The Electric Service Reliability application involves using electric energy storage to ensure highly reliable electric service. In the event of a complete power outage lasting more than a few seconds, the energy storage system provides enough energy to ride through outages of extended duration; complete an orderly shutdown of processes; and/or transition to on-site generation resources.

3.4.9.6.1 Overview

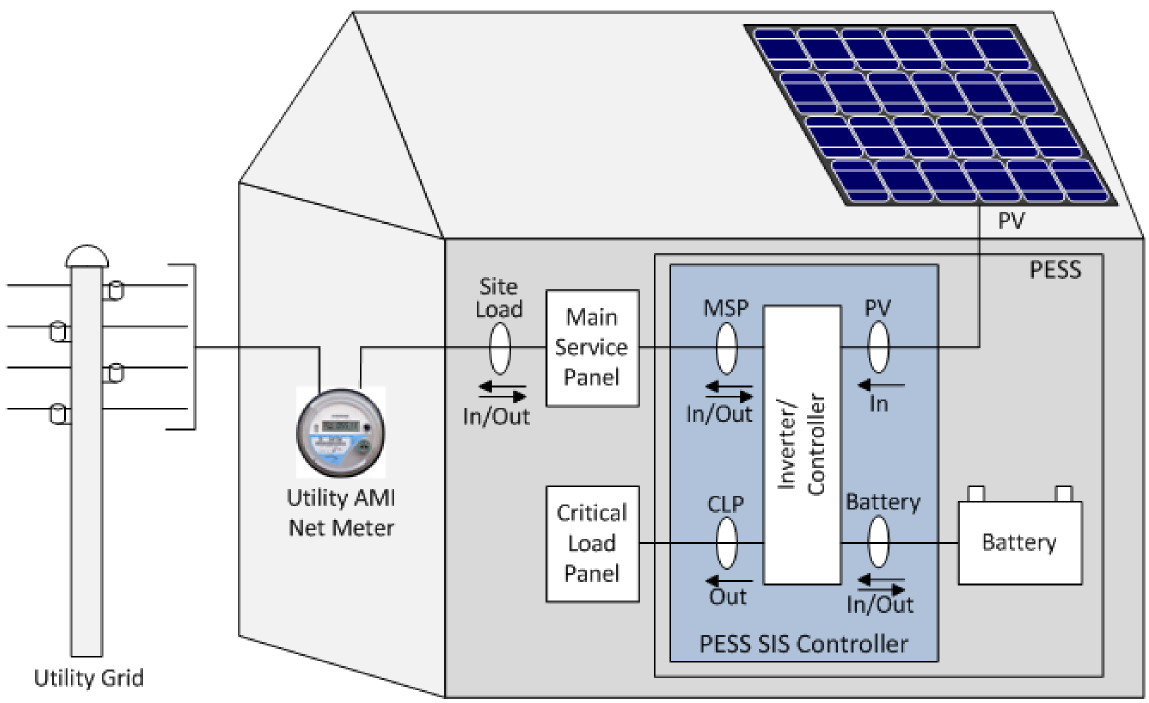
The following sections provide an overview of the operational, demonstration, testing, and evaluation methodology used for the Electric Service Reliability operational demonstration.

3.4.9.6.1.1 Description

A consumer PESS was installed at the SmartGrid Demonstration House in conjunction with the 2.82 kW solar PV array. The PESS consists of an 11.7 kWh lithium-ion battery with a unique hybrid inverter/converter rated for 6.0 kW discharge.

The PESS was configured as illustrated in Figure 3-210 to demonstrate how the consumer can benefit by using the PESS during extended power outages. This was accomplished by configuring the PESS to provide emergency stand-by power to critical loads during extended power outages.

Figure 3-210: PESS Installation at SmartGrid Demonstration House



3.4.9.6.1.2 Expected Results

This technical demonstration was expected to yield the following:

- Emergency stand-by power functionality would be demonstrated at the Demonstration House.
- An understanding would be developed for how much critical load the PESS could maintain indefinitely at the Demonstration House with the installed solar panels.

3.4.9.6.1.3 Benefit Analysis Method/Factors

The DOE SGCT was used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits were quantified.

- Reduced Sustained Outages
- Reduced Major Outages

Benefits were calculated using SGCT formulas. The following factors were measured, projected or calculated during the application operation and/or demonstration.

Reduced Sustained Outages

- SAIDI
- Total Residential Customers Impacted by Feeders or Lines (or PESS)
- Value of Service – Residential ($/kWh)
- Average Hourly Load Not Service During Outage per Customer – Residential (kWh)

Reduced Major Outages

- Outage Time of Major Outage – Residential
- Number of Customer affected by the Outage – Residential (or PESS)
- Value of Service – Residential ($/kWh)
- Average Hourly Load Not Service During Outage per Customer – Residential (kWh)

Additionally, the DOE ESCT was used to perform a benefit analysis for a customer-owned PESS system. The following Stationary Energy Storage applications were combined in this analysis.

- Primary Application – Time-of-Use Energy Cost Management
- Secondary Application – Renewable Energy Time Shift
- Secondary Application –Electric Service Reliability

Primary Benefit for Electric Service Reliability

- Reduced Outages (Consumer)

3.4.9.6.1.4 Testing Methodology

The following points provide an overview of how the operational demonstration and testing for this application was accomplished:

- A customer critical load panel and solar photovoltaic panels were installed and connected to the PESS.
- All energy delivered to and received from the PESS was measured by the PESS Solar Integration System (SIS). All PESS data collected was stored in the SIS data archive.
- Load served by the customer critical load panel was measured by the PESS SIS.
- Customer's main breaker was opened, simulating a power outage, and the PESS used its internal battery storage to maintain service to the critical loads panel.

3.4.9.6.1.5 Analytical Methodology

The following points provide an overview of the analytical methods that were used to evaluate the impact and benefits of this application:

- An annual solar generation profile previously developed for the Demonstration House was used to project the daily energy solar production that would be available to support emergency loads.

- The DC-DC efficiency factor previously calculated for solar energy shift was used to determine solar DC energy available after being stored by the battery.
- Typical daily energy usage of the customer loads that could be served from the emergency load panel were compiled from a search of industry literature.
- An analysis was performed to determine the length of time the PESS could sustain power to the customer critical load panel.
- The Reduced Outage Benefits to the consumer were calculated for inclusion in the Smart Grid Computational Tool and Energy Storage Computational Tools.

3.4.9.6.2 Plan Execution and Analysis

The following sections provide details regarding the functional tests performed, data collected, and analysis performed for the Electric Service Reliability operational test.

3.4.9.6.2.1 PESS UPS Configuration and Operation

Implementation of the PESS to support the Electric Service Reliability function required the installation of an electrical subpanel that would sustain the customer's critical loads during power grid outages. The following loads were determined to be essential and their electrical feed was reconfigured to be sourced from the critical load panel.

- Furnace fan
- Refrigerator
- Freezer
- Microwave
- Critical Lighting
- ISP Access , Home Network, and Security
- Sump Pump
- Outlet for charging for mobile phones, laptops, etc.

The manufacturer's operation manual recommends that the battery should not be routinely charged above 95% and discharged below 10% charge level to protect the battery and maintain its useful life. It also recommends reserving 10% battery capacity for UPS mode. These standard settings limit the output of the 11.7-kWh Lithium polymer battery to 1.17 kWh for unexpected outages of short duration. Under these settings the PESS could supply its maximum output, 6 kW, continuously to sustain emergency loads for approximately 10 - 12 minutes. Under these standard settings the PESS could sustain CLP loads of 6 kW through momentary and longer grid outages that are restored by automated switching.

When there is a higher probability of extended outages occurring, from either utility planned outages or weather predictions of snow/ice storms or severe thunderstorms, it is expected that the customer will suspend the normal operational settings of the PESS and reserve 90% of the battery for UPS mode. Under these revised settings the fully charged 11.7-kWh battery could supply 10.5 kWh for outages of longer duration. Under these settings the PESS could supply its maximum output, 6 kW, continuously to sustain critical load panel loads for approximately 1 ¾ hours.

3.4.9.6.2.2 Baseline Solar Generation Profile for PESS Analysis

To aid in determining the potential of a PESS to leverage solar generation further expand its ability to provide Electric Service Reliability, the project team constructed the solar generation profile for the Demonstration House using the composite per-unit solar generation load profile developed as part of the Distributed Rooftop Solar Generation function analysis.

Figure 3-211 shows the best and worst solar production days by season, and illustrates how variable the solar production is on a daily basis. Figure 3-212 shows the average daily solar production by month.

Figure 3-211: Demonstration House Solar kW – Typical Days

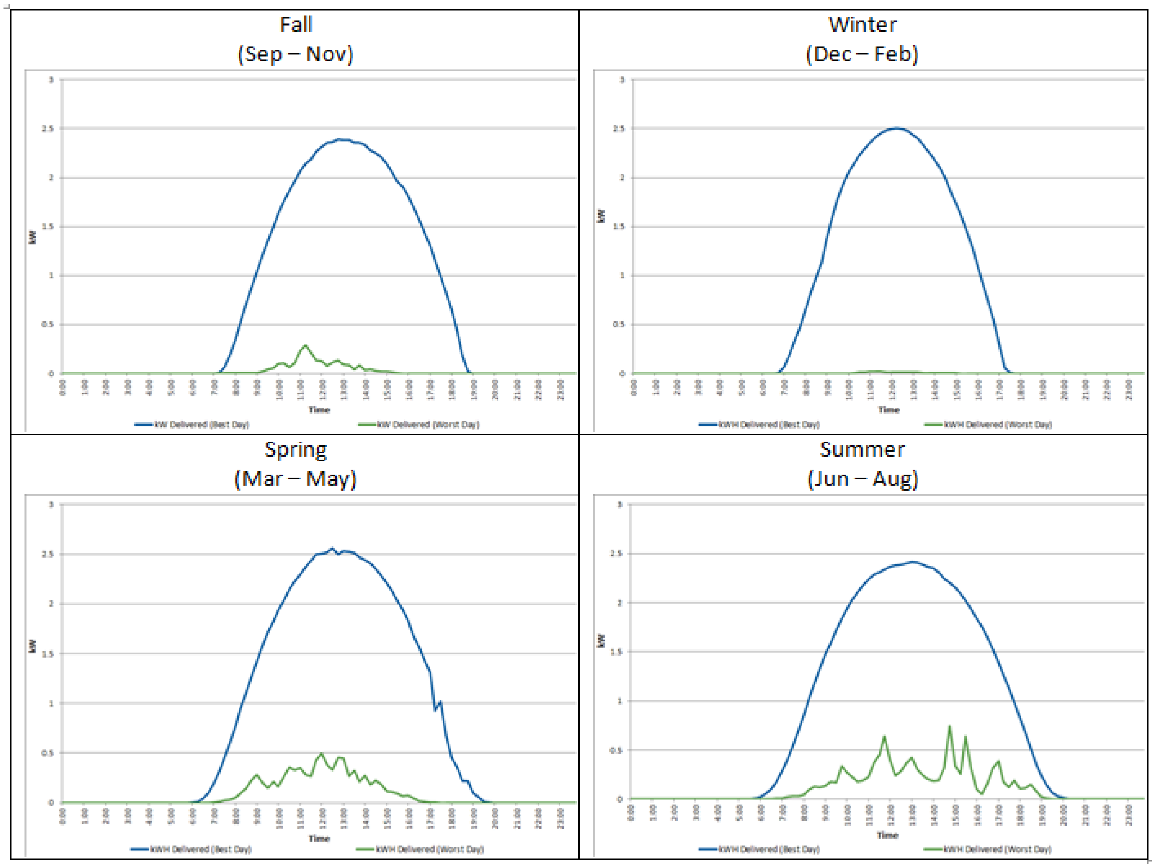
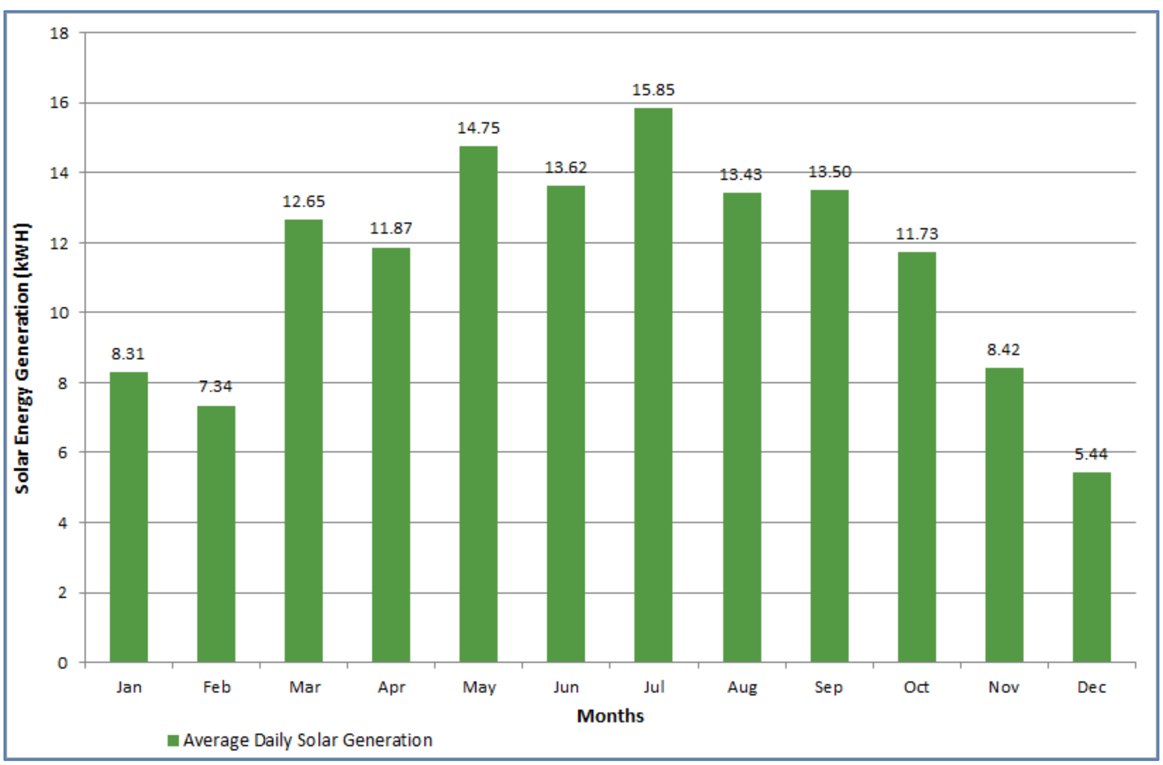


Figure 3-212: Demonstration House Average Daily Solar Energy Production



3.4.9.6.2.3 Baseline Critical Load Panel Daily Usage Profile

The SmartGrid Demonstration House electrical usage is not representative of a typical residential customer and could not be used to determine the typical energy delivered to a critical load panel for this analysis. The project team performed a literature search to ascertain typical daily usage characteristics for appliances and other customer loads that should be served by the critical load panel.

Most extended outages for the KCP&L service territory typically last only a few hours, but, on rare occasions, severe winter ice storms have caused widespread outages affecting large portions of KCP&L's service territory, taking 10-12 days to restore power to all customers. Therefore, the project team focused on appliances and other end-use loads that would be required during an extended winter storm restoration period. The results of this analysis are shown in Table 3-147 and show that these loads would typically require approximately 8 kWh of electricity daily if additional energy conservation measures were not initiated by the consumer.

It is important to note that the actual usage from individual customers' appliances may differ significantly from the values presented. Most of the values in the table are for newer appliances with Energy Star ratings. Older appliances may consume more; smaller or hyper-efficient models may use less energy. The analysis of critical loads to be powered assumes the following parameters, which are representative of the majority of customers in KCP&L's service territory:

- Heating is nonelectric; electricity powers the circulation fan.
- Water heating is gas-fired or, if electric, it is not powered during an outage.
- Electric cooking is limited to a microwave oven.
- Lighting is limited to a single lighting circuit.
- ISP modem/router and computer are powered by UPS to manage PESS.
- Sump pump, while fed from CLP, typically would not operate during winter storms.

Table 3-147: Critical Load Panel Winter Daily Energy Consumption by Use

Critical Loads	Rating (Watts)	Daily Use Assumptions	Annual Use (kWh)	Daily Use (kWh)
Gas Furnace Fan - 650 W 25% duty cycle	650	25 %		3.90
Refrigerator - 26CF, side-by-side, New, E Star			519	1.42
Freezer - 20cu Upright new, Energy Star			512	1.40
Microwave - 1200 w	1,200	30 min.		0.60
Critical Lighting 4 - 60w LED @9w	36	5 Hrs.		0.18
ISP Access , Home Network, Security	12	24 Hrs.		0.29
Sump Pump – ¾ HP	1,200	0 min.		0.00
Laptop - 41wh battery	65	3 charges		0.12
Total Daily Use				7.92

The development of the estimated energy required to operate the load connected to the critical load panel shows that the furnace fan represents half of the CLP energy consumption. To increase the ability of the PESS to sustain CLP loads for a longer period, the PESS customer should consider installing the most efficient furnace fan available and aggressively manage thermostat settings during non-solar-producing periods to further reduce furnace operation. Other energy-conserving measures the customer could adopt to extend storage capacity of the PESS would include minimizing the number of times the refrigerator/freezer doors are opened, and limiting the running of the freezer to periods of significant solar production.

3.4.9.6.2.4 Critical Load Sustainability Analysis

Using the manufacturer's recommendation that 10% of the battery capacity (1.17 kWh) be reserved for UPS mode, the PESS can supply its full 6 kW of output for 10-12 minutes, thus sustaining any CLP loads through momentary and short duration sustained grid outages that are restored by automated switching. But can the PESS sustain critical loads for outages longer than 10-12 minutes? Yes, based on the estimated average daily CLP consumption of 8.0 kWh, the default 1.17 kW of reserved storage could sustain the average CLP consumption for 3.5 hours and longer if the additional battery capacity was not previously discharged by other PESS functions and remained available. With an average sustained outage duration for customers in the SmartGrid Demonstration Area being just under 1.75 hours (CAIDI-101 min.), the default-reserved PESS storage could sustain the average CLP consumption for outages of durations twice the average.

Now, the remainder of the analysis focuses on the ability of the PESS to sustain the CLP requirements through extended outages. Most extended outages for the KCP&L service territory typically last only a few hours, but, on rare occasions, severe winter ice storms have caused widespread outages to large portions of KCP&L's service territory, taking up to 10-12 days to restore power to all customers. Since the standard UPS reserve can only supply the CLP requirements for approximately 3.5 hours, it is important that the customer change the operational setting and fully charge the PESS before periods of predicted snow/ice storms or severe thunderstorms, and prior to any scheduled outages.

In these circumstances, it is expected that the customer would suspend the normal operational settings of the PESS and reserve 90% of the battery capacity for UPS mode. Under these revised settings, the fully charged 11.7-kWh battery could supply 10.5 kWh during outages of longer duration. Under these settings the PESS could sustain the estimated average daily CLP consumption of 8.0 kWh for approximately 31 hours, and longer if solar generation were available. If the local solar PV system produced at least 8 kWh per day, the PESS could sustain the CLP consumption through extended outages indefinitely.

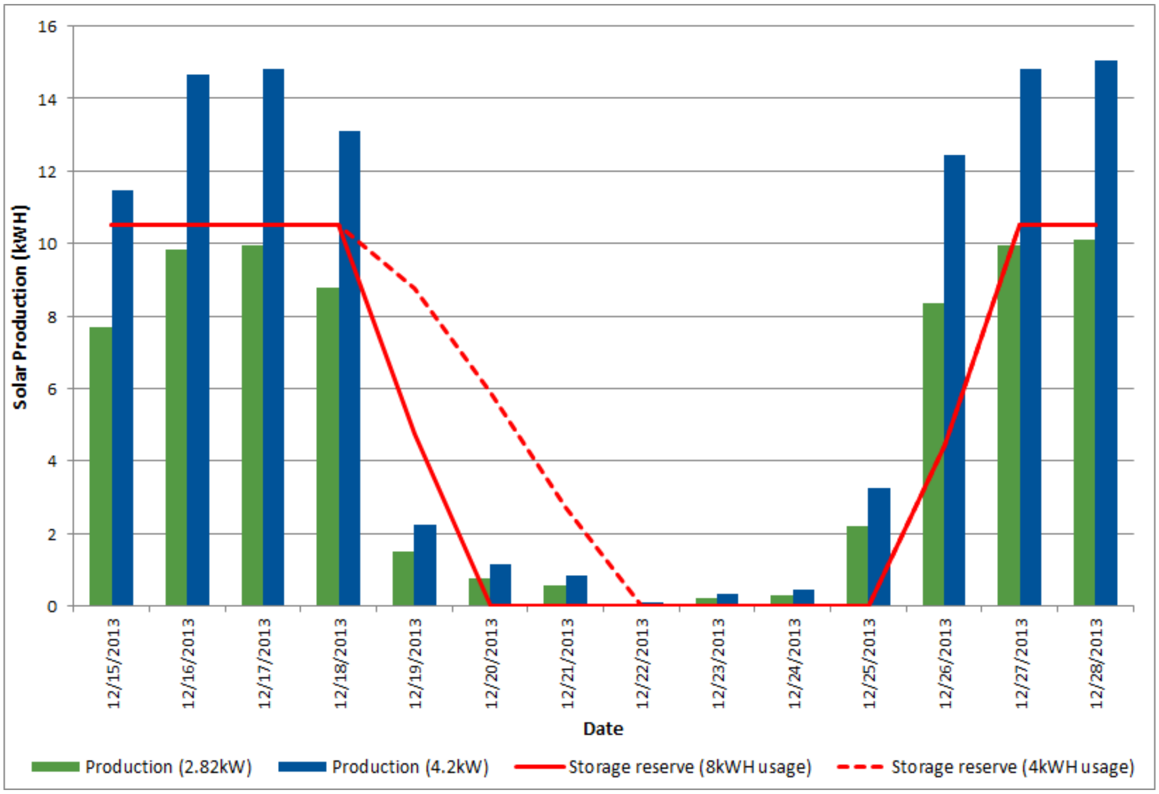
Table 3-148 shows the number of days per month that solar production falls below 8 kWh per day. Analysis of two PV systems are represented, one representing the 2.83-kW system installed at the Demonstration House, and the second a 4.2-kW system. The 4.2-kW system was picked for comparative analysis, as it would provide a minimum monthly daily average PV production of 8 kWh. As this table illustrates, there were a significant number of winter days during which the daily production fell below the consumption of the CLP, and the PESS capacity would be needed to sustain the CLP usage over several days. In many of these instances it may be possible for the customer to implement additional energy savings measures to maintain the CLP usage for the duration of the outage.

Table 3-148: Days with PV Production Less than CLP Consumption

PV	Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec	YRLY
2.82 kW	13	17	4	7	3	4	1	2	4	6	12	18	91
4.2 kW	6	10	3	6	1	1	0	0	3	4	9	13	56

However, on at least two occasions, as illustrated in Figure 3-213, the modeled PV generation was so low for an extended period that it would be unlikely that the PESS could have sustained the CLP usage if there had been a prolonged grid outage during this period of time. While the PESS may not have been able to sustain the CLP through the entirety of an extended outage under these conditions, the ability to sustain the critical load for 2 days could substantially minimize the customer impact. Figure 3-213 also shows that the PESS could potentially sustain the CLP loads for 4 days if the CLP usage was reduced by 50% with aggressive critical load management

Figure 3-213: Example Winter Period of Minimum Solar Production



3.4.9.6.2.5 Issues and Corrective Actions

The following issues and corrective action were encountered during the performance of the Electric Service Reliability operational testing and analysis.

Table 3-149: Issues and Corrective Actions

Issue	Corrective Action
• Due to technical issues and conflicting demonstrations at the Demonstration House, annual solar generation data was unable to be collected for this test.	• Used the per-unit solar generation profile developed in the Distributed Rooftop Solar Generation operational test.
• Demonstration House occupancy and CLP usage was not representative of a typical residential customer	• Team performed a literature search to ascertain typical daily usage characteristics for CLP loads.
• The SIS lost Internet connection to PESS during power outages.	• Cable Modem/Router power was transferred to the critical load panel.

3.4.9.6.3 Findings

The results obtained in the execution and analyses of the Electric Service Reliability operational testing are summarized in the sections below.

3.4.9.6.3.1 Discussion

The PESS installed at the Demonstration House is a 11.7-kWh lithium-ion battery with a unique hybrid 6.0-kW inverter/converter, normal operations of the PESS reserve 10% battery capacity (1.17 kWh) for UPS mode. Under these standard settings the PESS could sustain 6 kW of load through momentary and longer grid outages that are restored by automated switching. If the customer suspends the normal PESS operational settings and reserves 90% (10.5 kWh) of the battery for UPS mode, the PESS could supply 6 kW of loads continuously to sustain critical load panel loads for approximately 1 ¾ hours.

The project team performed a literature search to ascertain typical daily usage characteristics for appliances and other customer loads that should be served by the critical load panel. The results of this analysis show that these loads would typically require approximately 8 kWh of electricity daily if additional energy conservation measures were not initiated by the consumer.

Based on the estimated average daily CLP consumption of 8.0 kWh, the default operational settings of 1.17 kW of reserved storage could sustain the average CLP consumption for 3.5 hours, or longer if there were additional battery capacity not previously discharged by other PESS functions and remained available. With an average sustained outage duration for customers in the SmartGrid Demonstration Area being just under 1.75 hours (CAIDI-101 min.), the default-reserved PESS storage could sustain the average CLP consumption for outages of durations twice the average.

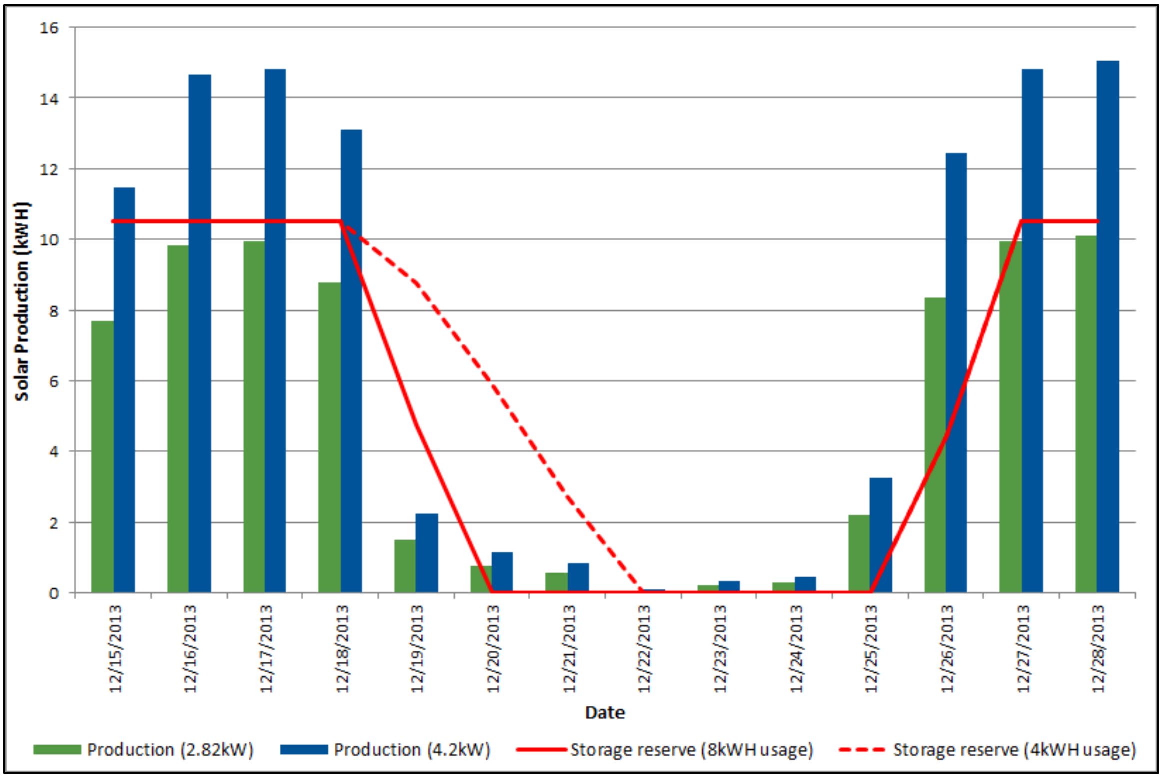
Most extended outages for the KCP&L service territory typically last only a few hours, but, on rare occasions, severe winter ice storms have caused widespread outages to large portions of KCP&L's service territory, taking up to 10-12 days to restore power to all customers. In these circumstances, it is expected that the customer would suspend the normal operational settings of the PESS and reserve 90% of the battery capacity for UPS mode. Under these revised settings the fully charged 11.7-kWh battery could supply 10.5 kWh for outages of longer duration. The PESS could then sustain the estimated average daily CLP consumption of 8.0 kWh for approximately 31 hours, or longer with solar generation available. If the local solar PV system produced at least 8 kWh per day, the PESS could sustain the CLP consumption through extended outages indefinitely.

The project team constructed solar generation profiles for two solar systems: one representing the 2.82-kW system installed at the Demonstration House, and the second, a 4.2-kW system that would provide a minimum monthly daily average PV production of 8 kWh. Detailed analyses of these solar generation profiles show that, in both cases, there are a significant number of winter days during which the daily production fell below the consumption of the CLP, and the PESS storage energy capacity would be used to sustain the CLP usage during extended outages lasting multiple days.

PV	Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec	YRLY
2.82 kW	13	17	4	7	3	4	1	2	4	6	12	18	91
4.2 kW	6	10	3	6	1	1	0	0	3	4	9	13	56

However, on at least two occasions, as illustrated in Figure 3-214, the modeled PV generation was so low for an extended period that it was unlikely that the PESS could have sustained the CLP usage if there had been a prolonged grid outage during this period of time. While the PESS may not have been able to sustain the CLP through the entirety of an extended outage under these conditions, the ability to sustain the critical load for 2 days could substantially minimize the customer impact. Figure 3-214 also shows that the PESS could potentially sustain the CLP loads for 4 days if the CLP usage was reduced by 50% with aggressive critical load management

Figure 3-214: Example Winter Period of Minimum Solar Production



3.4.9.6.3.2 Expectations vs. Actuals

The following table provides a comparison of the Expected Results and the Actual Outcomes for the Electric Service Reliability operational test.

Table 3-150: Expected Results vs. Actual Outcomes

Expected Results	Actual Outcome
• Emergency standby power functionality will be demonstrated at the Demonstration House.	• A critical load panel was installed and the PESS was configured for emergency standby power operation, and the functionality was demonstrated.
• Develop an understanding of how much critical load the PESS can maintain indefinitely at the Demonstration House with the installed solar panels.	• PESS as normally configured (10% UPS) can sustain CLP through momentary and short-duration outages. • When reconfigured for UPS operations, the PESS storage alone can sustain CLP loads for more than a day. • Combined with the Demonstration House solar array (2.82 kW), the PESS could sustain CLP load for multiday restorations throughout most of the non-winter months. • Combined with a slightly larger array (4.2 kW) and/or very active CLP energy usage management, PESS could sustain CLP loads for multiday restorations throughout most of the year. • The PESS may be unable to sustain CLP loads for multiday restorations during extended periods (3+ days) of minimal solar production without CLP load reductions.

3.4.9.6.3.3 Computational Tool Factors

The following table lists the values derived from the Electric Service Reliability operational test analysis that will be used as inputs to the Energy Storage Computational Tool.

Table 3-151: Computational Tool Values

Name	Description	Calculated Value
SAIDI	System Average Interruption Duration Index is defined as: Total Customer Hours Interrupted/Total Customers Served.	181.48 min. 3.025 Hr.
Outage Time of Major Outage - Residential	Total outage time experienced by residential customers from an interruption of electric service that is categorized as a major event by IEEE Std. 1366-2003	294.43 Min 4.91 Hr.
Outage Minutes Avoided by Residential Customers	The total outage minutes avoided by residential customers as a result of energy storage devices being used to provide power during system interruptions.	475.91 Min
Average Hourly Load Not Service During Outage per Customer – Residential (kWh)	These inputs represent the average hourly load (kW) of a typical residential, commercial, or industrial customer within the project scope. This average hourly load will be used to calculate the unserved electricity during an outage event.	1.178 kWh
Value of Service – Residential ($)/kWh)	Represents the true value of the electricity service to the specified customer without regard to the actual cost of providing the service. This input captures the value of service reliability quantified by the willingness of customers to pay for service reliability, taking into account the resources (e.g., income) of the residential customer or by a firm's expected net revenues associated with the added reliability.	$2.27 /kWh

- <u>SAIDI:</u> The analysis will use the 3 year average of the reported project level Impact Metrics values.

- <u>Outage Time of Major Outage – Residential:</u> This value has been calculated based on a 15-year average of outages classified as major events by IEEE and excluded from the standard indices calculations. This value is calculated as follows:

  15yr Average SAIDI for major events – 294.43 Min/Cust

  3.025 Hr + 294.43 min/cust ÷ 60 min/hr = 4.91 hr.

- <u>Outage Minutes Avoided by Residential Customers (Min):</u> Based on the project level indices, this value is calculated as follows:

  SAIDI (Min) + Outage Time of Major Outages-Residential (Min) =

  181.48 min + 294.43 min = 475.91 min

- Average Hourly Load Not Service During Outage per Customer – Residential (kWh): Based on the energy consumption of the "typical" residential customer used for all PESS analysis this value is calculated as follows:

  10,319 kWh/year ÷ 8760 hours/year = 1.178 kWh/hr

- Value of Service – Residential ($/kWh): The DOE/LBNL ICECalculator [31] (Interruption Cost Estimate Calculator) was used to calculate the value with the following input parameters.

  Modified default values for the report's "typical" residential customer, with a detached single family house using 10,319 kWh/year yielded $2.10 /kWh (2011 $)
  Applied 2% annual escalation to yield $2.27 /kWh (2015 $)

3.4.9.6.4 Lessons Learned

Throughout the conduct of the operational testing and analysis of the PESS for the Electric Service Reliability function, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- The manufacturer's recommendation for protecting the battery and maintaining its useful life is that the battery should not be routinely charged above 95% nor discharged below 10% charge level. This limitation must be factored in when sizing the battery storage component for any PESS.
- The PESS ratings, 6.0 kW/11.7 kWh, appear to appropriately sized to serve the critical loads of most residential homes in the KCP&L service area. Combining the PESS with a
- 4.2-kW solar array would allow the CLP loads to be sustained through multiday restorations for the majority of the year.
- In the Kansas City region during the winter months, occasionally there are periods extending several days with minimal solar production. The PESS may be unable to sustain CLP loads for multiday restorations during these extended periods of minimal solar production without reductions in the CLP loads.
- It is important for the customer to understand the energy consumption characteristics of the loads connected to the CLP. Approximately half of the daily energy consumption may be attributed to the furnace fan. To extend the ability of the PESS to sustain loads during outages, the customer should consider installing the most efficient furnace fan available and to manage thermostat settings to further reduce furnace operation.
- To further extend the ability of the PESS to improve its ability to sustain loads during outages, the customer should implement additional energy management measures, which would include only running certain appliances (freezer, computer while charging, etc.) during times of significant solar production.
- It is critical that the customer's home network and ISP connection remain operational during power outages. Without the ISP connection, the customer's ability to monitor and manage the PESS is lost. It may be necessary for the customer to have a backup cellular internet connection for the PESS if the customer's normal home ISP supplier loses service due to widespread power outages.

3.4.9.7 PEV Charging

The batteries in plug-in electric vehicles (PEVs) can be portrayed as nonstationary energy storage devices. As such, they are similar to stationary energy storage devices and support economic, reliability and environmental benefits. By increasing vehicle fuel efficiency, they also support Reduced Oil Usage, an Energy Security Benefit.

3.4.9.7.1 Overview

The following sections provide an overview of the operational, demonstration, testing, and evaluation methodology used for the PEV Charging operational test.

3.4.9.7.1.1 Description

The ChargePoint VCMS and a total of 10 Electric Vehicle Charging Stations (EVCSs) will be deployed within the SGDP area. Each EVCS consists of a dual port, level 2 (240V) Coulomb Charging Station capable of charging two PEVs simultaneously. The EVCSs was installed on the EVCS sponsor's side of the meter, with charging free to the public. The VCMS was integrated with the DERM and serves as the "control authority" for each EVCS during demand response events.

3.4.9.7.1.2 Expected Results

This technical demonstration was expected to yield the following:

- Technical demonstration of 10 EVCSs, accessible to the public and providing PEV owners the convenience of public charging.
- The DERM would dispatch DR events to the EVCS, demonstrating how PEVs can participate in DR events.
- KCP&L would be able to monitor, record, and summarize the charging patterns at each EVCS site.

3.4.9.7.1.3 Benefit Analysis Method/Factors

The DOE SGCT was used to perform the SGDP benefit analysis. For this application the following Smart Grid Function benefits were quantified.

- Reduced CO_2 Emissions

Benefits were calculated using SGCT formulas. The following factors were measured, projected, or calculated during the application operation and/or demonstration.

Reduced CO_2 Emissions

- Annual Electricity Consumed by PEVs (kWh)

3.4.9.7.1.4 Demonstration Methodology

The following points provide an overview of how the operational demonstration of this application was be accomplished:

- Energy use at each PEV charging station was measured through PEV Charge Management System and the AMI system deployed as part of the Project. All data collected by the AMI system was be stored in KCP&L's MDM) system.

3.4.9.7.1.5 Analytical Methodology

The Technical Demonstration of this application does not require any analytical calculations.

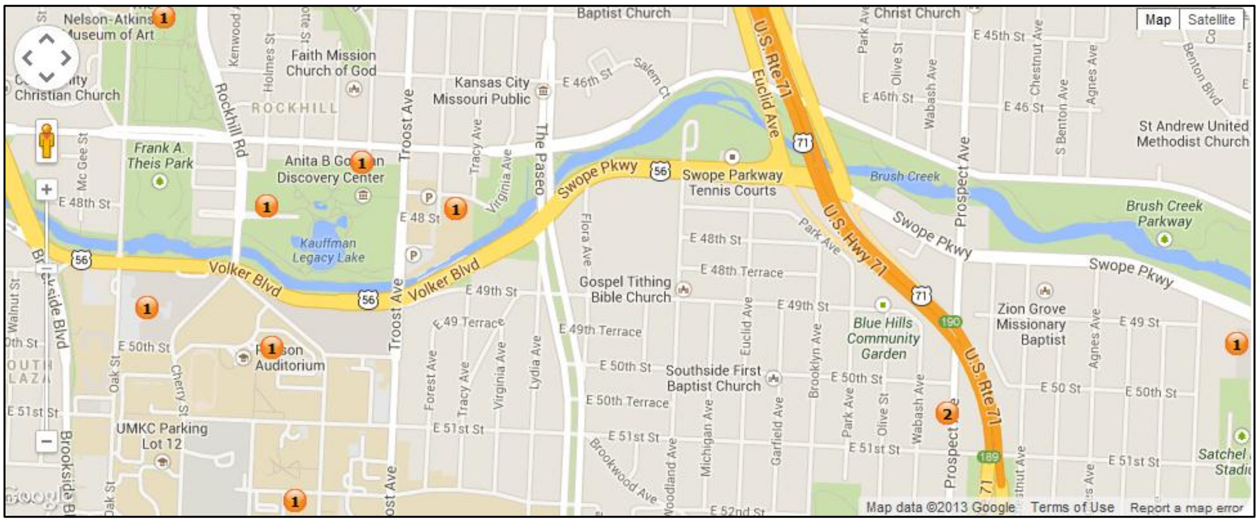
3.4.9.7.2 Plan Execution and Analysis

The following sections provide details regarding the functions, data collection, and evaluation performed for the PEV Charging demonstration.

3.4.9.7.2.1 PEV Charging Station Installations

As part of this SGDP, KCP&L installed 10 EVCSs at locations illustrated in Figure 3-215. Each EVCS consists of a dual port, level 2 (L2) (240V) Coulomb CT2021 Charging Station with SAE J1772 standard connectors. Each EVCS is equipped with a cellular modem that enables two-way communications with the ChargePoint web platform. This allows electric vehicle owners to locate and reserve individual EVCSs by using web mapping applications. These charging stations are free for electric vehicle owners to use.

Figure 3-215: ChargePoint Map of SmartGrid EVCS Locations



KCP&L has installed an additional 22 EVCSs throughout the Kansas City Metropolitan Area, at locations illustrated in Figure 3-216. Ten (10) of these additional EVCSs are combination L1/L2 stations installed as part of a Clean Cities project, which also received federal funding. The remaining 12 EVCSs are Level 2 stations installed as part of an internal KCP&L test marketing program.

Figure 3-217 shows the deployment schedule of all stations during the SGDP's Operational Test period.

KCP&L monitors and manages all of these EVCSs via the ChargePoint web platform. Station summaries — including usage and inventory reports, reservation schedules, and audit reports — are readily available through the platform and were used in the analysis presented in the following section.

Figure 3-216: ChargePoint Map of All KCP&L EVCS Locations

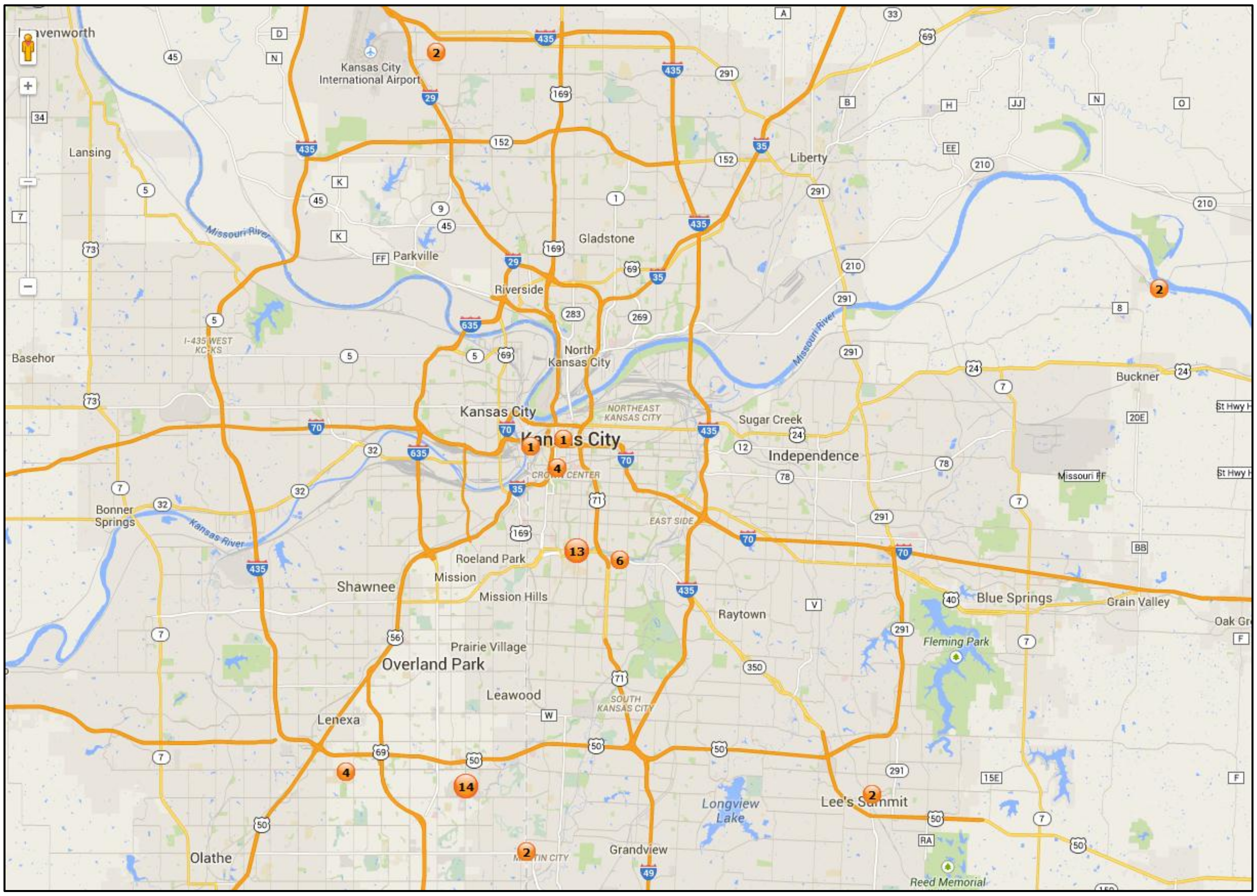
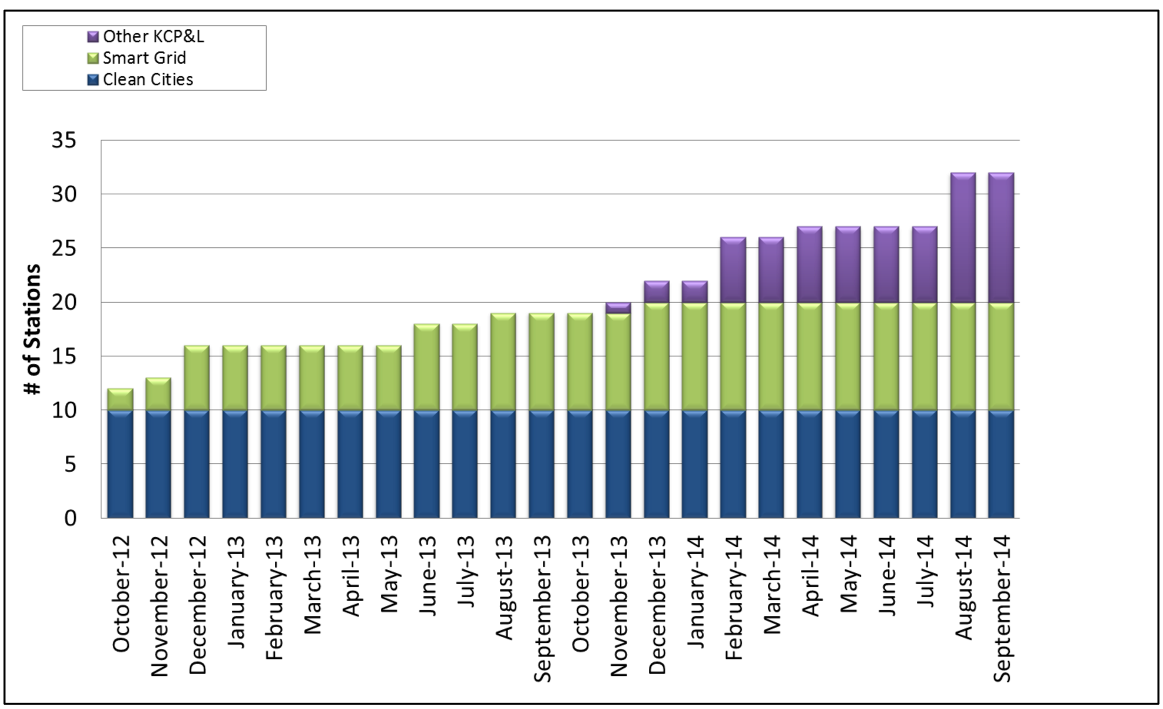


Figure 3-217: EV Charging Station Deployment by Month



3.4.9.7.2.2 Electric Vehicle Charge Station Utilization

Figure 3-218 illustrates the total charging session per month for all EVCSs, and Figure 3-219 illustrates the average number of charging session per EVCS by program (SmartGrid, Clean Cities, and other KCP&L).

Figure 3-218: Total EVCS Charging Sessions by Month

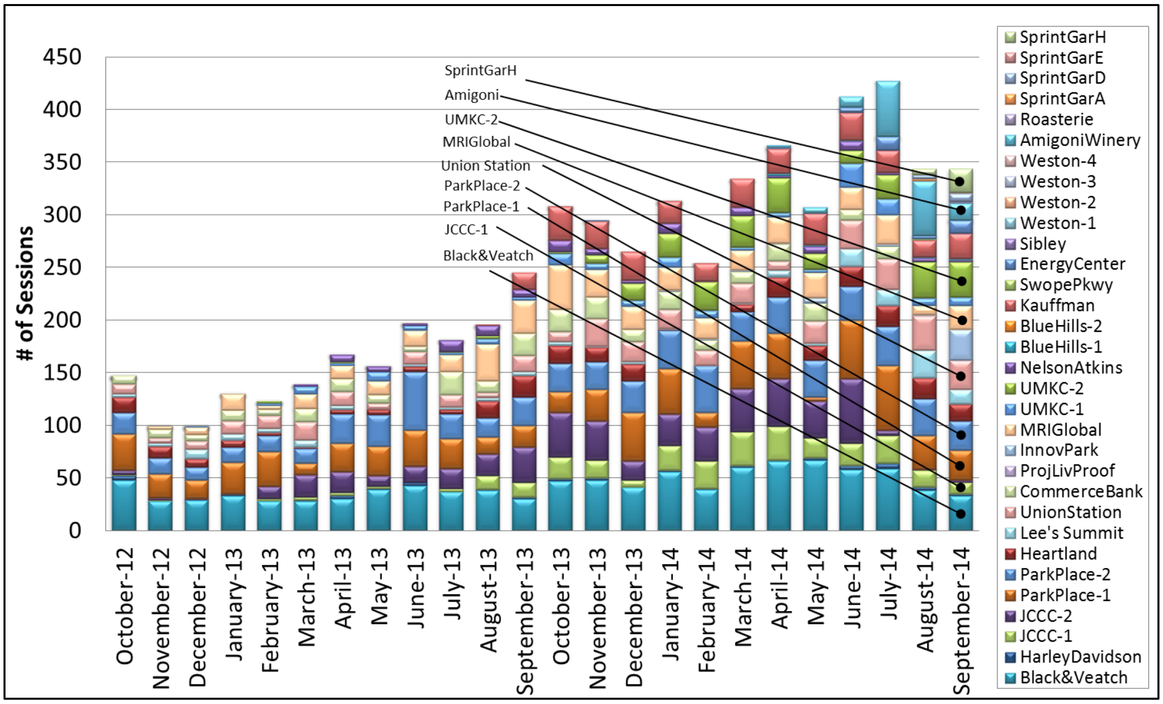


Figure 3-219: Average EVCS Charging Sessions by Month (by Program)

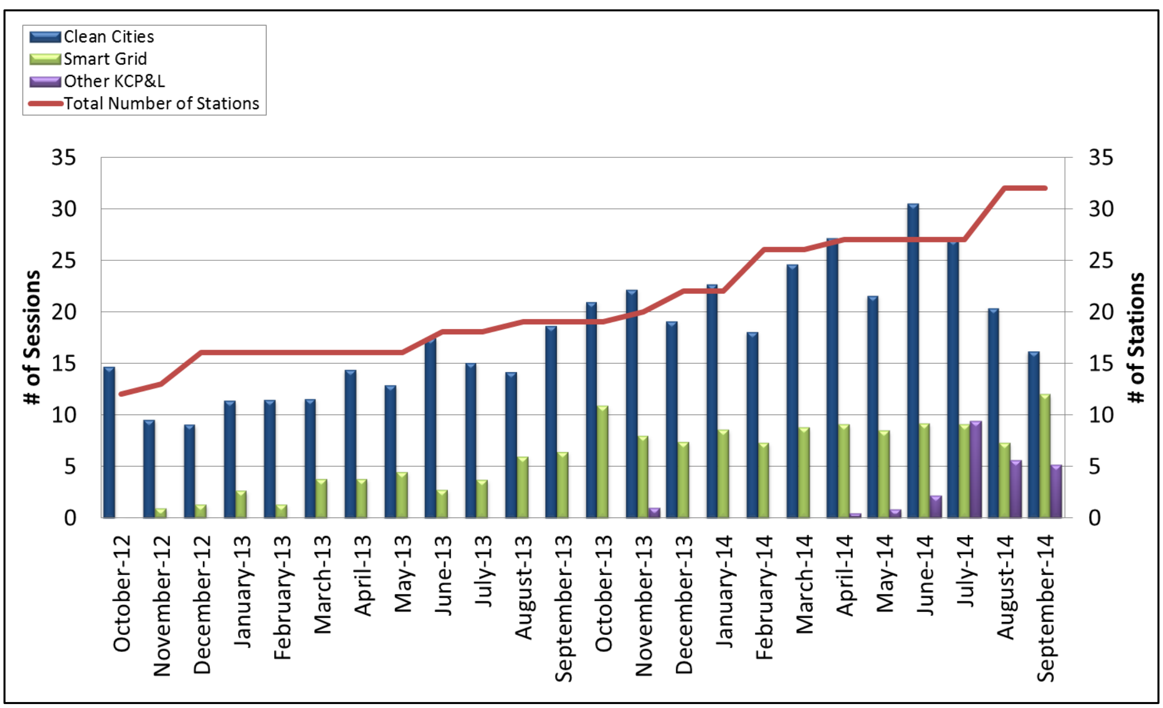


Figure 3-220 depicts the total kWh consumption per month for all EVCSs, and Figure 3-221 depicts the average kWh consumption per EVCS by program (SmartGrid, Clean Cities, and other KCP&L).

Figure 3-220: Total EVCS kWh Consumption by Month

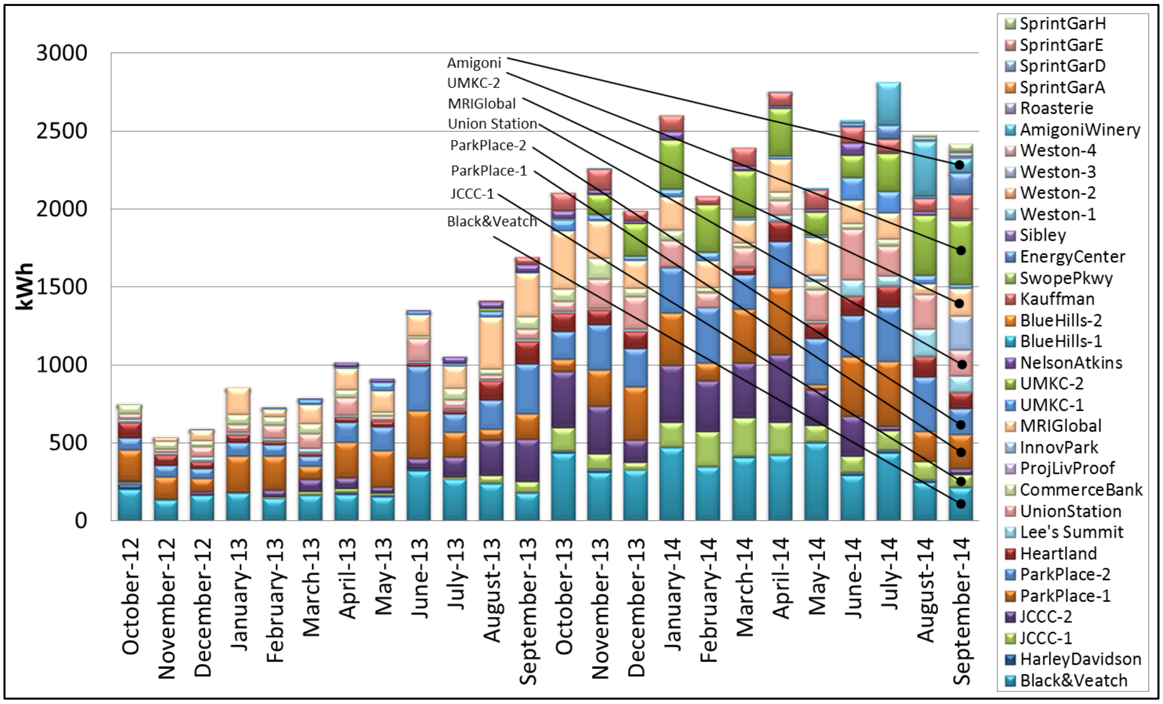
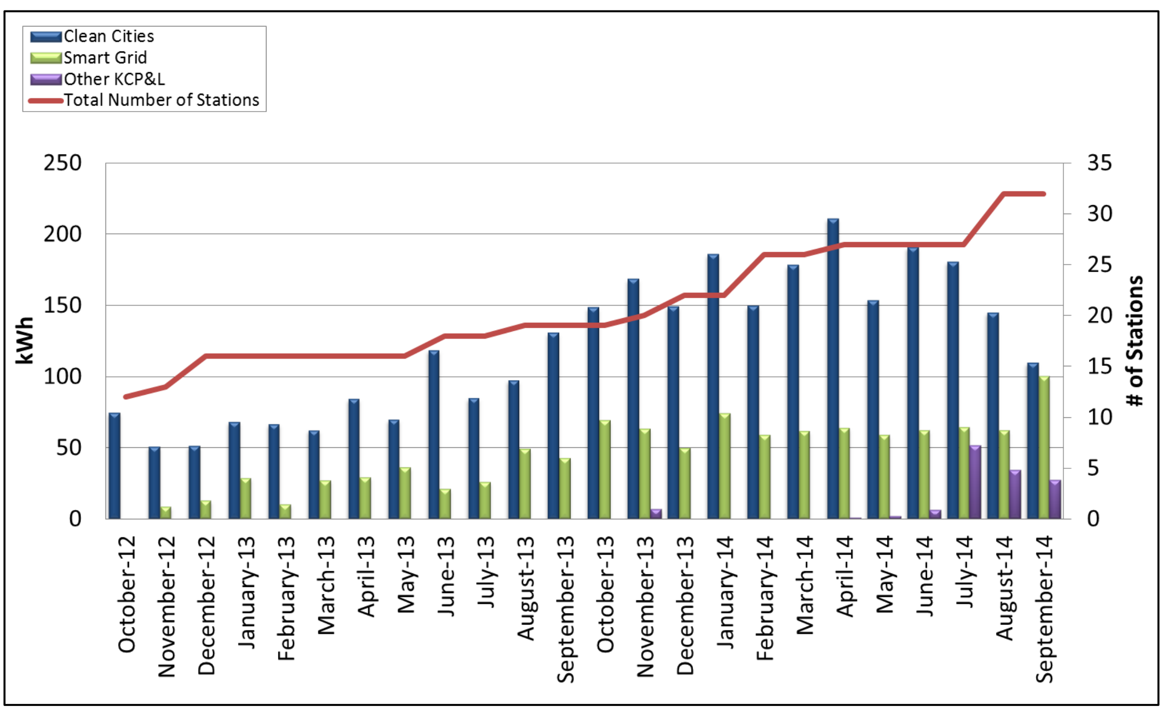


Figure 3-221: Average EVCS kWh Consumption by Month (by Program)



3.4.9.7.2.3 PEV Charging Results

Figure 3-222 depicts the average EVCS Session Connect Time over time and Figure 3-223 depicts the average EVCS Session Charge Time over time for all EVCSs (SmartGrid, Clean Cities, and other KCP&L).

Figure 3-222: Average EVCS Charge Session – Connect Time

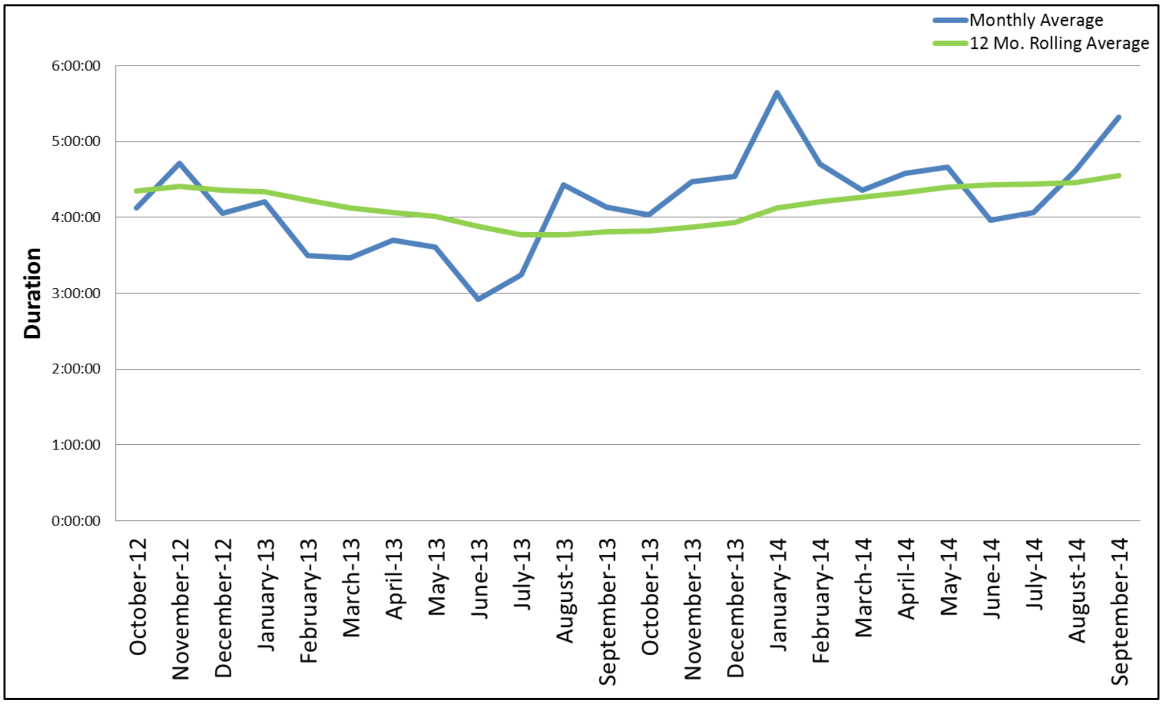


Figure 3-223: Average EVCS Charge Session – Charge Time

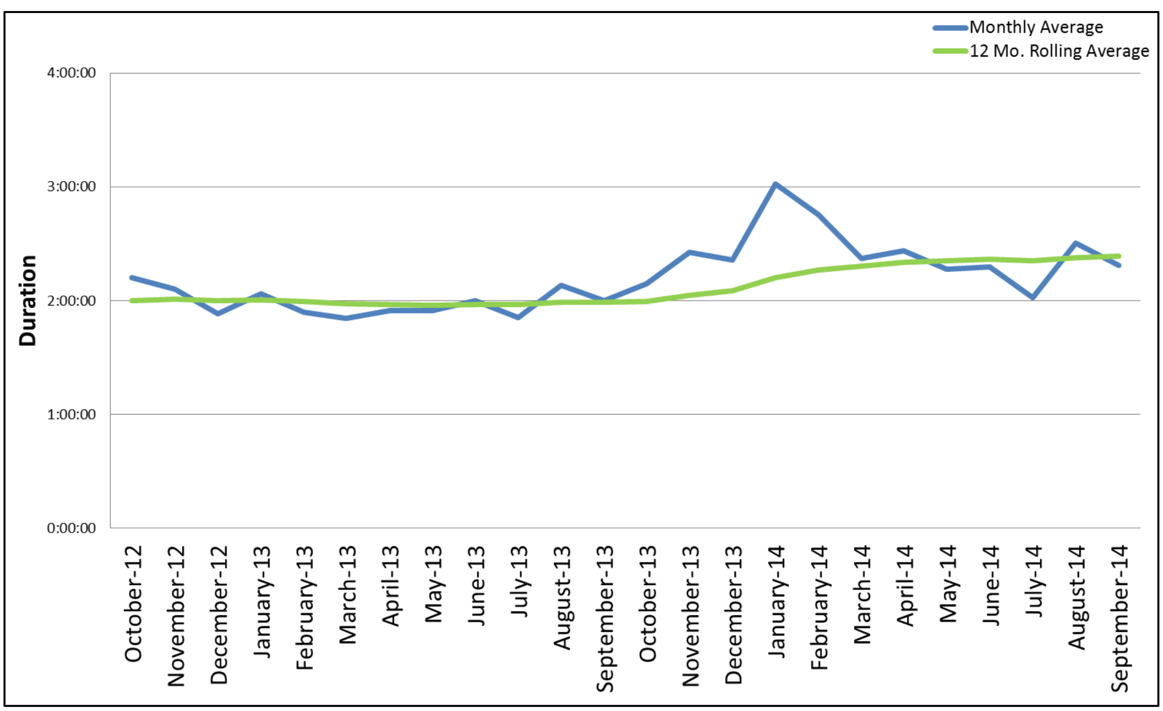


Figure 3-224 depicts the average EVCS Session kWh consumption over time for all EVCSs and Figure 3-225 — a scatter plot of all charging sessions for the August 2014 — illustrates the two most common charge rates used by the Kansas City PEV population.

Figure 3-224: Average EVCS Charge Session – kWh

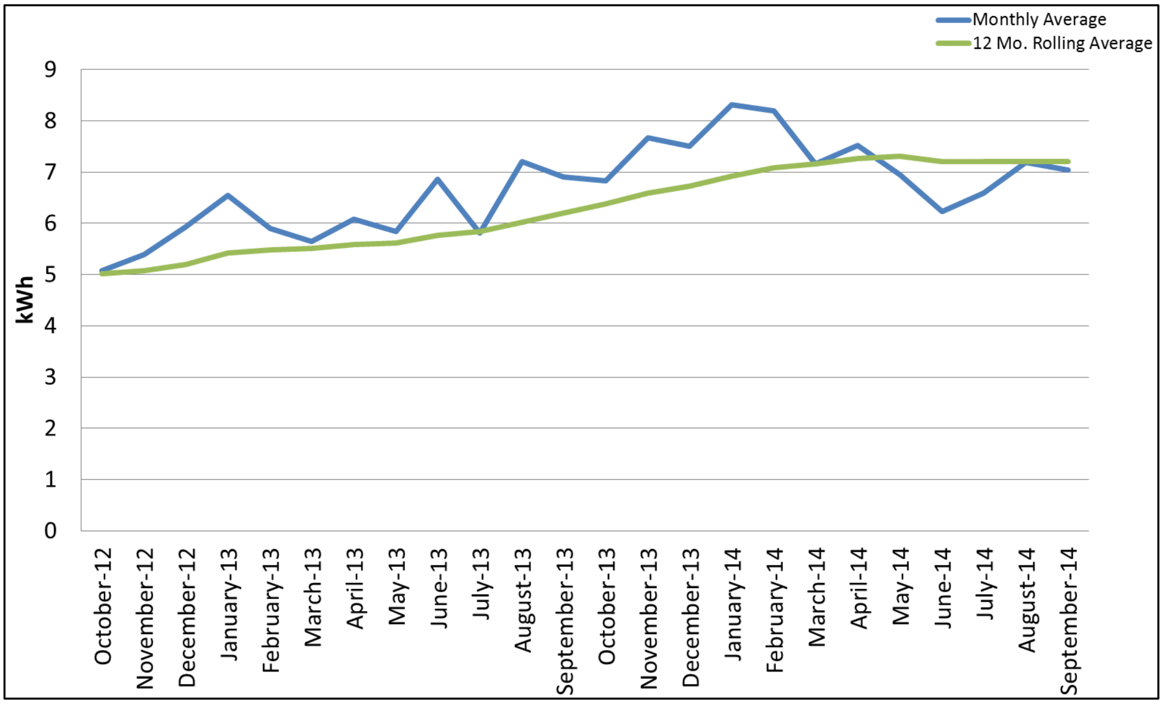
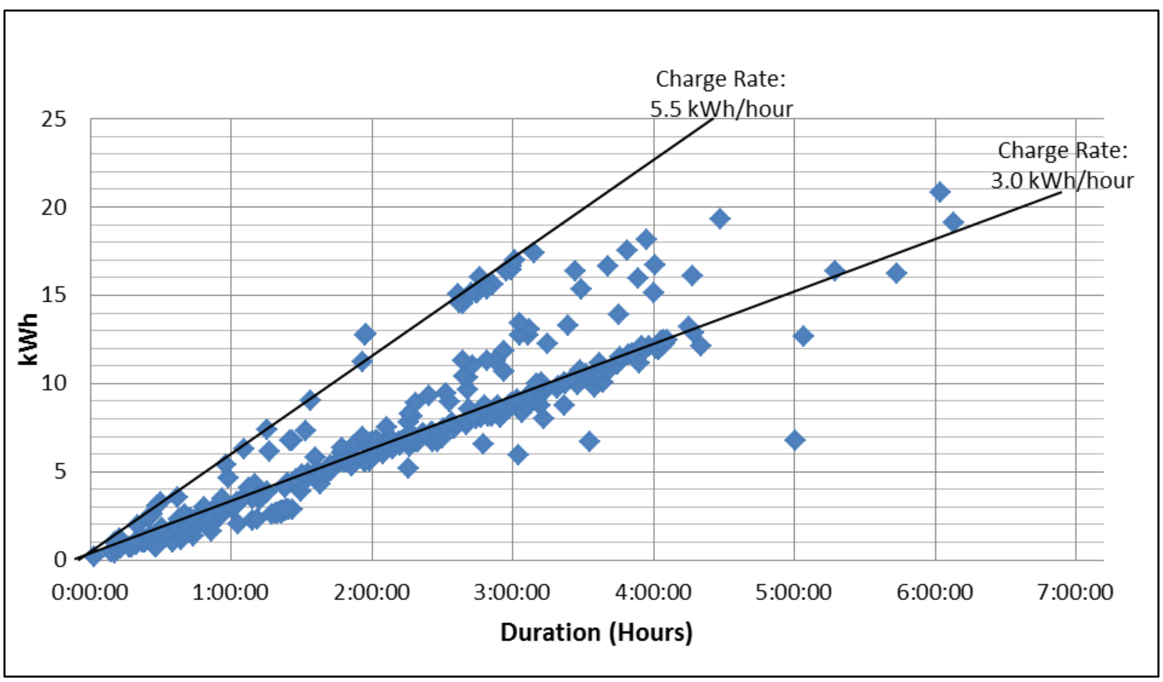


Figure 3-225: EVCS Session Charge Rates



3.4.9.7.2.4 PEV Charging Station Participation in DR Event

As part of the demand response demonstration, KCP&L worked with OATI and ChargePoint to build an interface between the DERM and the VCMS. Unlike most of the vendor-to-vendor interfaces, this one was not routed through the ESB; rather, it was a point-to-point interface between the two vendors. ChargePoint's existing API was utilized to communicate the necessary information between the two systems.

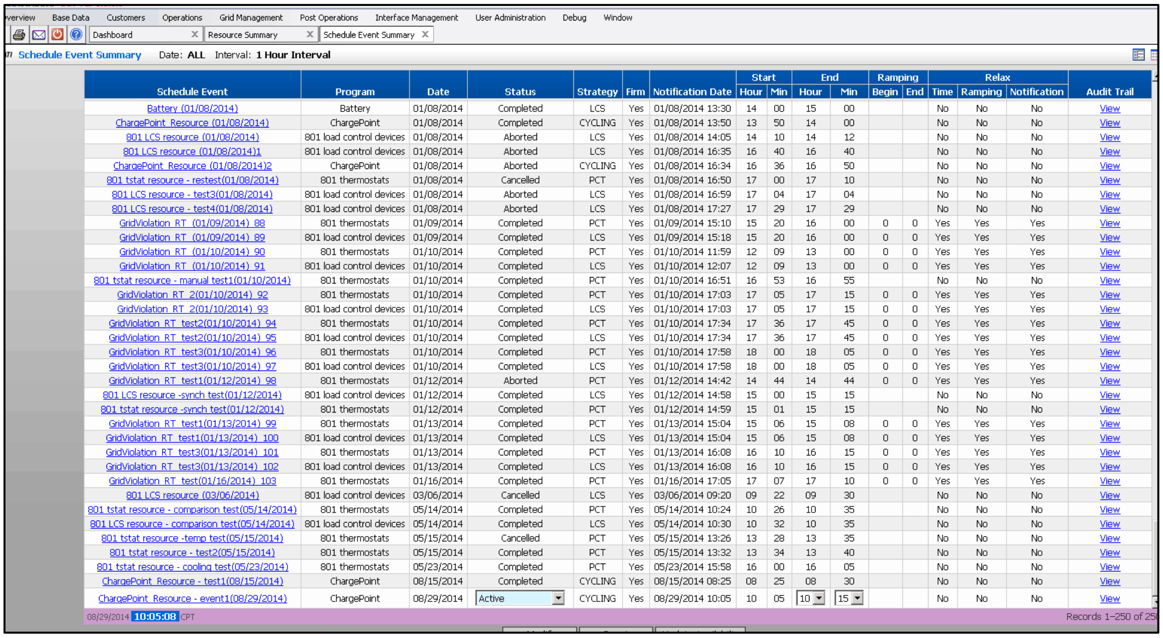
To demonstrate the charging station participation in DR events, KCP&L triggered several events specifically targeted to the Innovation Park charging station. KCP&L also completed one event with a PEV actually plugged into the charging station. Several pictures and screenshots are shown below, but the complete screenshots from this event demonstration are contained in Appendix K.

Figure 3-226 below shows the ChargePoint charge station management dashboard (specifically, the Innovation Park station) during the event. As indicated below, the load shed level was at 100% during the event.

Figure 3-226: ChargePoint Dashboard During PEV DR Event

Figure 3-227 below shows the DERM event summary screen during the event. As shown in the last line, the ChargePoint program was Active during the demand response event.

Figure 3-227: DERM Event Summary During PEV DR Event



Overview Base Data Customers Operations Grid Management Post Operations Interface Management User Administration Debug Window

Dashboard | Resource Summary | Schedule Event Summary

Schedule Event Summary Date: ALL Interval: 1 Hour Interval

Schedule Event	Program	Date	Status	Strategy	Firm	Notification Date	Start Hour	Start Min	End Hour	End Min	Ramping Begin	Ramping End	Relax Time	Relax Ramping	Relax Notification	Audit Trail
Battery (01/08/2014)	Battery	01/08/2014	Completed	LCS	Yes	01/08/2014 13:30	14	00	15	00			No	No	No	View
ChargePoint_Resource (01/08/2014)	ChargePoint	01/08/2014	Completed	CYCLING	Yes	01/08/2014 13:50	13	50	14	00			No	No	No	View
801 LCS resource (01/08/2014)	801 load control devices	01/08/2014	Aborted	LCS	Yes	01/08/2014 14:05	14	10	14	12			No	No	No	View
801 LCS resource (01/08/2014)1	801 load control devices	01/08/2014	Aborted	LCS	Yes	01/08/2014 16:35	16	40	16	40			No	No	No	View
ChargePoint_Resource (01/08/2014)2	ChargePoint	01/08/2014	Aborted	CYCLING	Yes	01/08/2014 16:34	16	36	16	50			No	No	No	View
801 tstat resource - restest(01/08/2014)	801 thermostats	01/08/2014	Cancelled	PCT	Yes	01/08/2014 16:50	17	00	17	10			No	No	No	View
801 LCS resource - test3(01/08/2014)	801 load control devices	01/08/2014	Aborted	LCS	Yes	01/08/2014 16:59	17	04	17	04			No	No	No	View
801 LCS resource - test4(01/08/2014)	801 load control devices	01/08/2014	Aborted	LCS	Yes	01/08/2014 17:27	17	29	17	29			No	No	No	View
GridViolation_RT_(01/09/2014)_88	801 thermostats	01/09/2014	Completed	PCT	Yes	01/09/2014 15:10	15	20	16	00	0	0	Yes	Yes	Yes	View
GridViolation_RT_(01/09/2014)_89	801 load control devices	01/09/2014	Completed	LCS	Yes	01/09/2014 15:18	15	20	16	00	0	0	Yes	Yes	Yes	View
GridViolation_RT_(01/10/2014)_90	801 thermostats	01/10/2014	Completed	PCT	Yes	01/10/2014 11:59	12	09	13	00	0	0	Yes	Yes	Yes	View
GridViolation_RT_(01/10/2014)_91	801 load control devices	01/10/2014	Completed	LCS	Yes	01/10/2014 12:07	12	09	13	00	0	0	Yes	Yes	Yes	View
801 tstat resource - manual test1(01/10/2014)	801 thermostats	01/10/2014	Completed	PCT	Yes	01/10/2014 16:51	16	53	16	55			No	No	No	View
GridViolation_RT_2(01/10/2014)_92	801 thermostats	01/10/2014	Completed	PCT	Yes	01/10/2014 17:03	17	05	17	15	0	0	Yes	Yes	Yes	View
GridViolation_RT_2(01/10/2014)_93	801 load control devices	01/10/2014	Completed	LCS	Yes	01/10/2014 17:03	17	05	17	15	0	0	Yes	Yes	Yes	View
GridViolation_RT_test2(01/10/2014)_94	801 thermostats	01/10/2014	Completed	PCT	Yes	01/10/2014 17:34	17	36	17	45	0	0	Yes	Yes	Yes	View
GridViolation_RT_test2(01/10/2014)_95	801 load control devices	01/10/2014	Completed	LCS	Yes	01/10/2014 17:34	17	36	17	45	0	0	Yes	Yes	Yes	View
GridViolation_RT_test3(01/10/2014)_96	801 thermostats	01/10/2014	Completed	PCT	Yes	01/10/2014 17:58	18	00	18	05	0	0	Yes	Yes	Yes	View
GridViolation_RT_test3(01/10/2014)_97	801 load control devices	01/10/2014	Completed	LCS	Yes	01/10/2014 17:58	18	00	18	05	0	0	Yes	Yes	Yes	View
GridViolation_RT_test1(01/12/2014)_98	801 thermostats	01/12/2014	Aborted	PCT	Yes	01/12/2014 14:42	14	44	14	44	0	0	Yes	Yes	Yes	View
801 LCS resource -synch test(01/12/2014)	801 load control devices	01/12/2014	Completed	LCS	Yes	01/12/2014 14:58	15	00	15	15			No	No	No	View
801 tstat resource -synch test(01/12/2014)	801 thermostats	01/12/2014	Completed	PCT	Yes	01/12/2014 14:59	15	01	15	15			No	No	No	View
GridViolation_RT_test1(01/13/2014)_99	801 thermostats	01/13/2014	Completed	PCT	Yes	01/13/2014 15:04	15	06	15	08	0	0	Yes	Yes	Yes	View
GridViolation_RT_test1(01/13/2014)_100	801 load control devices	01/13/2014	Completed	LCS	Yes	01/13/2014 15:04	15	06	15	08	0	0	Yes	Yes	Yes	View
GridViolation_RT_test3(01/13/2014)_101	801 thermostats	01/13/2014	Completed	PCT	Yes	01/13/2014 16:08	16	10	16	15	0	0	Yes	Yes	Yes	View
GridViolation_RT_test3(01/13/2014)_102	801 load control devices	01/13/2014	Completed	LCS	Yes	01/13/2014 16:08	16	10	16	15	0	0	Yes	Yes	Yes	View
GridViolation_RT_test(01/16/2014)_103	801 thermostats	01/16/2014	Completed	PCT	Yes	01/16/2014 17:05	17	07	17	10	0	0	Yes	Yes	Yes	View
801 LCS resource (03/06/2014)	801 load control devices	03/06/2014	Cancelled	LCS	Yes	03/06/2014 09:20	09	22	09	30			No	No	No	View
801 tstat resource - comparison test(05/14/2014)	801 thermostats	05/14/2014	Completed	PCT	Yes	05/14/2014 10:24	10	26	10	35			No	No	No	View
801 LCS resource - comparison test(05/14/2014)	801 load control devices	05/14/2014	Completed	LCS	Yes	05/14/2014 10:30	10	32	10	35			No	No	No	View
801 tstat resource -temp test(05/15/2014)	801 thermostats	05/15/2014	Cancelled	PCT	Yes	05/15/2014 13:26	13	28	13	35			No	No	No	View
801 tstat resource - test2(05/15/2014)	801 thermostats	05/15/2014	Completed	PCT	Yes	05/15/2014 13:32	13	34	13	40			No	No	No	View
801 tstat resource - cooling test(05/23/2014)	801 thermostats	05/23/2014	Completed	PCT	Yes	05/23/2014 15:58	16	00	16	05			No	No	No	View
ChargePoint_Resource - test1(08/15/2014)	ChargePoint	08/15/2014	Completed	CYCLING	Yes	08/15/2014 08:25	08	25	08	30			No	No	No	View
ChargePoint_Resource - event1(08/29/2014)	ChargePoint	08/29/2014	Active	CYCLING	Yes	08/29/2014 10:05	10	05	10	15			No	No	No	View

08/29/2014 10:05:08 CPT Records 1–250 of 25

Figure 3-228 below shows the text message that was received by the PEV owner during the event, notifying her that her vehicle was no longer receiving charge.

Figure 3-228: Text Message Sent to PEV Owner During PEV DR Event

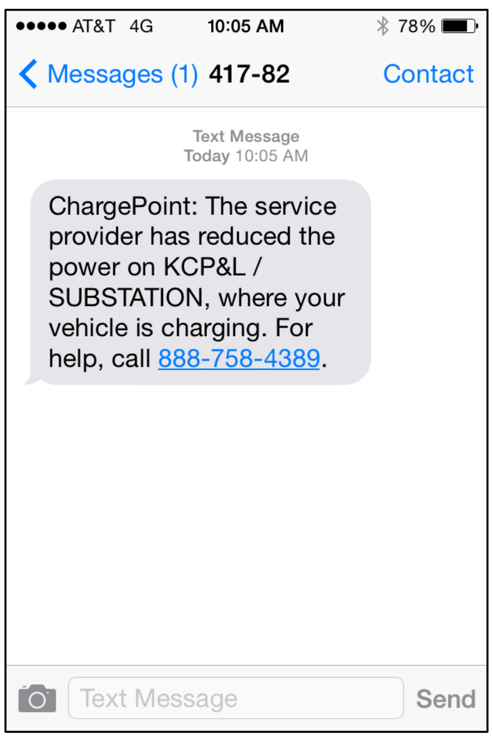
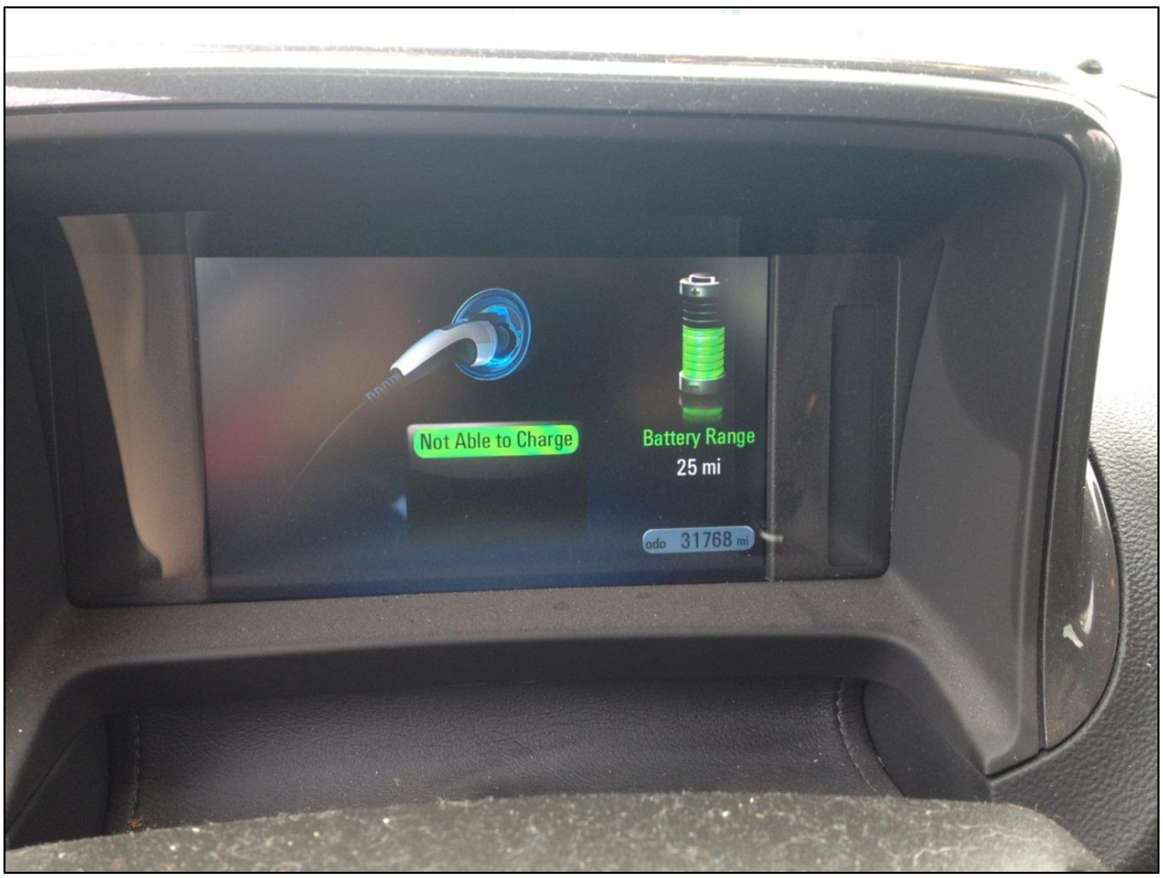


Figure 3-229 below shows the message displayed on the charging station during the DR event. The text scrolling across the display read: “#1: SUSPENDED” on the top line and “LOAD SHED IN PROGRESS/TAP CARD TO END” on the bottom line.

Figure 3-229: Charge Station Message During PEV DR Event

Figure 3-230 below shows the PEV dashboard during the DR event. It displayed “Not Able to Charge”.

Figure 3-230: PEV Dashboard During PEV DR Event



3.4.9.7.2.5 Issues and Corrective Actions

No issues requiring corrective action were encountered during the performance of the PEV Charging operational demonstration.

3.4.9.7.3 Findings

The results obtained in the execution and analyses of PEV Charging operational demonstration are summarized in the sections below.

3.4.9.7.3.1 Discussion

KCP&L has installed 32 EVCSs throughout the Kansas City Metropolitan Area. Ten of the EVCSs were directly funded by this SGDP. An additional 10 are combination L1/L2 stations installed as part of a Clean Cities project, which also received federal funding. The remaining 12 EVCSs are Level 2 stations installed as part of an internal KCP&L test marketing program. The operational performance of all 32 stations was tracked and analyzed for this analysis.

Site selection has proven key to early utilization of the EVCSs. The EVCSs deployed under the Clean Cities program have experienced higher utilization, as they were placed at locations with high EV usage potential. In contract, the SmartGrid demonstration EVCSs were limited to placement within the SGDP boundary, an area with a relatively low potential EV population. Even so, utilization for all charging stations has increased over time as the EV population increases and as EV owners become aware of the EVCS locations.

Through 2014, total EVCS kWh consumption leveled out at approximately 2.5 MWh per month. During this period of flat consumption, KCP&L deployed additional EVCSs, causing average station consumption to drop.

Based on monitoring of all EVCSs, the following characteristics were uncovered regarding charge sessions.

- Annual Electricity Consumed by PEVs is 28.586 MWh
- Average Connect Time is 4.5 hours
- Average Charge Duration is 2 hours, 20 minutes
- Average Charge is approx. 7 kWh
- Most common Charge Rate is 3 kWh/hour
- Less common Charge Rate is 5.5 kWh/hour

KCP&L also demonstrated the EVCS and EV participation in DR events. While KCP&L did not call any DR events in 2014 due to abnormally cool weather, an analysis was conducted upon the potential EVCS contribution to an event if one would have been called on the utility's 2014 peak hour, which occurred from 4 PM to 5 PM on August 25, 2014. During this hour, two (2) charging sessions were active but only one EV was actually charging. If a DR event had been called, a single 3.2-kW charge session would have been interrupted.

3.4.9.7.3.2 Expectations vs. Actuals

The following table provides a comparison of the Expected Results and the Actual Outcomes for the PEV Charging operational demonstration.

Table 3-152: Expected Results vs. Actual Outcome

Expected Results	Actual Outcome
• Technical demonstration of 10 EVCSs, accessible to the public	• Successfully deployed 10 SGDP EVCSs and applied the knowledge learned to additional KCP&L test market installations.
• The DERM will dispatch DR events to the EVCS, demonstrating how PEVs can participate in DR events.	• The DERM dispatched DR events to the EVCS demonstrating how PEVs can participate in DR events.
• KCP&L will be able to monitor, record, and summarize the charging patterns at each of the EVCS sites.	• KCP&L developed an understanding of typical PEV charging session characteristics, including charge session connection duration, charge duration, charge rate, and kWh consumption.

3.4.9.7.3.3 Computational Tool Factors

The following table lists the values derived from the PEV Charging operational demonstration that will be used as inputs to the Smart Grid Computational Tool and the Energy Storage Computational Tool.

Table 3-153: Computational Tool Values

Name	Description	Calculated Value
Annual Electricity Consumed by PEVs	The total electricity consumed by PEVs in the service territory	28,586 kWh

3.4.9.7.4 Lessons Learned

Throughout the conduct of the operational demonstration, testing, and evaluation of the PEV Charging function, numerous considerations were realized and should be noted for future implementations. These Lessons Learned are as follows:

- Site selection is key to the early utilization of a public EVCS. The best sites are locations where potential PEV owners work, or are businesses where PEV owners frequent, usually an hour or so at a time. Having moderate wait times provides enough time for a user to charge a vehicle, while also generating enough vehicle turnover to make the charging station available to multiple users. With increased exposure comes increased acceptance and, it follows, use.
- Monitoring of all EVCS locations generated the following generalizations regarding usage of charging stations.
  - Annual Electricity Consumed by PEVs is 28.586 MWh
  - Average Connect Time is 4.5 hours
  - Average Charge Duration is 2 hours, 20 minutes
  - Average Charge is approx. 7 kWh
  - Most common Charge Rate is 3 kWh/hour
  - Less common Charge Rate is 5.5 kWh/hour
- While considerable DR potential exists for use of EVCSs, the potential for reducing KCP&L's system peak (typically 4 PM to 5 PM) in the foreseeable future is very limited.

3.5 Metrics and Benefits Reporting

The SGDP operational demonstrations and testing, outlined in the previous section, were performed to not only demonstrate the SmartGrid Functions achievable through end-to-end interoperability, but to also capture and quantify the operational benefits achievable by each of the SmartGrid applications. EPRI and the DOE have developed specific, quantifiable methodologies to translate benefit metrics into potential monetary value. KCP&L used the DOE-developed metrics reporting and computational tools to evaluate the overall costs and benefits of the demonstrated SmartGrid technologies and functions. The results of this reporting and analysis are summarized in the following subsections.

3.5.1 Build Metrics

Build Metrics were reported on a quarterly basis as outlined in the MBRP. The list of reported metrics was approved by the DOE and is listed in Appendix A. The final cumulative build metrics were submitted on October, 31, 2014 for the quarter ending September 30, 2014. All submitted build metrics, including baselines, can be found in Appendix S.

3.5.1.1 Build Metrics Calculations

The following tables list the calculated values for each of the reported build metrics along with the method used to calculate them.

Table 3-154: Build Metrics for KCP&L's AMI Assets

Metric	Units	Final Reported Value		Calculation
		Project	System	
End-Points (meters)	# endpoints	13,483	231,571	Count of Normal meters from AMI Head-End
Portion of Customers with AMI: residential	# endpoints	12,259	207,674	Count of Normal meters in residential rate classes from AMI Head-End
Portion of Customers with AMI: commercial	# endpoints	1,224	23,399	Count of Normal meters in commercial rate classes from AMI Head-End
Portion of Customers with AMI: industrial	# endpoints	0	498	Count of Normal meters in industrial rate classes from AMI Head-End
Reading interval for meters	minutes	15	15	N/A
Remote Connect/Disconnect	Yes/No # endpoints	Yes 13,003	Yes 26,904	Count of Normal meters from AMI Head-End that have this capability, based on meter model
Outage Reporting	Yes/No # endpoints	Yes 13,483	Yes 231,571	Count of Normal meters from AMI Head-End – All of the KCP&L installed AMI meters have this capability
Power Quality Measurement	Yes/No # endpoints	No	No	N/A
Tamper Detection	Yes/No # endpoints	Yes 13,483	Yes 231,571	Count of Normal meters from AMI Head-End – All of the KCP&L installed AMI meters have this capability

Metric	Units	Final Reported Value		Calculation
		Project	System	
Integration with Billing System	Yes/No Description	Yes AMI is integrated with enterprise Oracle CIS.	Yes AMI is integrated with enterprise Oracle CIS.	N/A
Integration with Customer Information System	Yes/No Description	Yes AMI is integrated with KCP&L enterprise Oracle CIS. The project AMI was incorporated into the existing AMR – CIS interfaces. CIS daily account/meter synchronization. AMI provides CIS daily register meter reads for direct billing. CIS daily billing cycle-to-date usage info and bill prediction pushed to IHDs via AMI Network.	Yes AMI is integrated with KCP&L enterprise Oracle CIS. The project AMI was incorporated into the existing AMR – CIS interfaces. CIS daily account/meter synchronization. AMI provides CIS daily register meter reads for direct billing. CIS daily billing cycle-to-date usage info and bill prediction pushed to IHDs via AMI Network.	N/A
Integration with Outage Management System	Yes/No Description	Yes AMI is integrated with enterprise OMS. An additional project OMS (redundant) will also be implemented in conjunction with a DMS. The project AMI was incorporated into the existing AMR to enterprise OMS interfaces including meter outage alerts and meter "ping" functionality to verify power restoration.	Yes AMI is integrated with enterprise OMS. An additional project OMS (redundant) will also be implemented in conjunction with a DMS. The project AMI was incorporated into the existing AMR to enterprise OMS interfaces including meter outage alerts and meter "ping" functionality to verify power restoration.	N/A

Metric	Units	Final Reported Value		Calculation
		Project	System	
Integration with Distribution Management System	Yes/No Description	Yes DMS is integrated with multiple project and legacy systems including AMI, DERM, OMS, and energy storage.	Yes DMS is integrated with multiple project and legacy systems including AMI, DERM, OMS, and energy storage.	N/A
Integration with Other Enterprise System	Yes/No Description	Yes Data Mining and Analysis Tool covered by the MDA	Yes Data Mining and Analysis Tool covered by the MDA	N/A
Backhaul Network	Description	Hybrid of Fiber and Wireless Raven radio with network carrier	Hybrid of Fiber and Wireless Raven radio with network carrier	N/A
Meter Communication Network	Description	Landis+Gyr Gridstream RF 900MHz - Collectors and Routers	Landis+Gyr Gridstream RF 900MHz - Collectors and Routers	N/A
Head-end System	Description	Landis+Gyr Command Center	Landis+Gyr Command Center	N/A
Meter Data Management System	Description	eMeter/Siemens	eMeter/Siemens	N/A
Meter Data Analysis System	Description	The project AMI was incorporated into the existing AMR – MDA interfaces. AMI daily register reads and 15-min interval reads are loaded into MDA on a daily basis.	The project AMI was incorporated into the existing AMR – MDA interfaces. AMI daily register reads and 15-min interval reads are loaded into MDA on a daily basis.	N/A
		Project Funded	Cost Share	
Back Office Systems Cost	$	$2,337,739	$2,157,913	Costs associated with installation of the AMI meter software and MDM system
Communications Equipment Cost	$	$119,308	$110,130	Costs associated with installation of the AMI network
AMI Smart Meters Cost	$	$2,252,704	$2,076,390	Costs associated with purchase of the AMI meters

Table 3-155: Build Metrics for KCP&L's Customer System Assets

Metric	Units	Final Reported Value		Calculation
		Project	System	
In-Home Displays	# devices Description	616 Tendril InSight	616 Tendril InSight	Count of Normal devices from AMI Head-End
Direct Load Control Devices	# devices Description	131 Tendril Volt	131 Tendril Volt	Count of Normal devices from AMI Head-End
Programmable Communicating Thermostats	# devices Description	112 Tendril Setpoint	53,824 Tendril Setpoint and Honeywell PCTs	Count of Normal devices from AMI Head-End for project. System includes KCP&L thermostat program.
Smart Appliances	# devices Description	0	0	N/A
Energy Management Devices/Systems	# devices Description	0	0	N/A
Home Area Network Gateways	# devices Description	61 Tendril Transport Gateway	61 Tendril Transport Gateway	Count of Normal devices from AMI Head-End
Home Area Network	Description	ZigBee SEP 1.0	ZigBee SEP 1.0	N/A
Web Portal	# w/access # active acct Description	12,036 2,109 Tendril Energize Web Portal	12,036 2,109 Tendril Energize Web Portal	Count of customers with access and active accounts from enrollment tracking.
		Project Funded	Cost Share	
Back Office Systems Cost	$	$441,625	$406,255	Costs associated with installation of the back office systems
Web Portals Cost	$	$940,730	$868,293	Costs associated with installation and maintenance of the web portal
In-Home Displays Cost	$	$155,669	$143,694	Costs associated with purchase and installation of the IHDs
Direct Load Control Devices Cost	$	$90,344	$83,395	Costs associated with purchase and installation of the DLC devices
Smart Appliances Cost	$	$0	$0	N/A
Programmable Communicating Thermostats Cost	$	$378,345	$335,076	Costs associated with purchase and installation of the PCTs
Home Area Network Gateways Cost	$	$228,510	$204,484	Costs associated with purchase and installation of the HAN Gateways
Other Costs	$	$390,761	$357,473	Program delivery costs including KCP&L labor for program administration, analysis, and customer engagement as well as vendor travel expenses.

Table 3-156: Build Metrics for KCP&L's Pricing Programs

Metric	Units	Final Reported Value		Calculation
		Project	System	
Flat Rate	Yes/No # with access # enrolled Description	No N/A N/A	Yes N/A 162,409 KCP&L has multiple residential and C&I Flat Rates that occur during both summer and winter.	Not able to calculate how many customers have access. Count of customers with Flat Rate codes from system query.
Flat Rate with Critical Peak Pricing	Yes/No	No	No	N/A
Flat Rate with Peak-Time Rebate	Yes/No	No	No	N/A
Tiered Rate	Yes/No # with access # enrolled Description	No	Yes N/A 694,691 KCP&L has multiple existing residential and C&I Tiered Rates. A majority of those are declining block rates.	Not able to calculate how many customers have access. Count of customers with Tiered Rate codes from system query.
Tiered Rate with Critical Peak Pricing	Yes/No	No	No	N/A
Tiered Rate with Peak-Time Rebate	Yes/No	No	No	N/A
Time-of-Use Rate	Yes/No # with access # enrolled Description	Yes 12,259 102 A new residential TOU rate is being piloted as part of this project to augment the evaluation of customer information systems and control devices.	Yes N/A 341 KCP&L has multiple existing residential and C&I TOU Rates.	For project, all residential AMI customers have access. Not able to calculate how many customers have access for system. Count of customers with TOU Rate codes from system query.
Time-of-Use Rate with Critical Peak Pricing	Yes/No	No	No	N/A
Time-of-Use Rate with Peak-Time Rebate	Yes/No	No	No	N/A

Metric	Units	Final Reported Value		Calculation
		Project	System	
Real-Time Pricing	Yes/No # with access # enrolled Description	No	Yes N/A 9 KCP&L has multiple existing RTP rates for commercial and industrial customers.	Not able to calculate how many customers have access. Count of customers with RTP Rate codes from system query.
Real-Time Pricing with Critical Peak Pricing	Yes/No	No	No	N/A
Real-Time Pricing with Peak Time Rebate	Yes/No	No	No	N/A
Variable Peak Pricing	Yes/No	No	No	N/A
Pre-Pay Pricing	Yes/No	No	No	N/A
Net Metering	Yes/No # with access # enrolled Description	No	Yes N/A 2,336 KCP&L has multiple existing residential and C&I Net Metering Rates.	Not able to calculate how many customers have access. Count of customers with Net Metering Rate codes from system query.
Rate Decoupling	Yes/No	No	No	N/A

Table 3-157: Build Metrics for KCP&L's Distributed Energy Resources

Metric	Units	Final Reported Value		Calculation
		Project	System	
Distributed Gen.: Number of Units Distributed Gen.: Installed Capacity Distributed Gen.: Total Energy Delivered	# MW MWh	9 176.11 28,310.57	2,361 46,055.126 N/A	Project numbers are for project solar PV systems. System numbers include solar PV and wind systems throughout the KCP&L and KCP&L-GMO region.
Energy Storage: Number of Units Energy Storage.: Installed Capacity Energy Storage: Total Energy Delivered	# MW MWh	1 1,000 45,645.32	1 1,000 45,645.32	Calculations for the 1 battery system installed as part of this project. No additional systems have been installed.
PEV Charging: Number of Units PEV Charging: Installed Capacity PEV Charging: Total Energy Delivered	# points MW MWh	19 133.2 3,738	57 370.8 10,049	Project numbers include the 10 EV charging stations in the Green Impact Zone. System numbers also include all KCP&L-owned charging stations throughout the KC metro area.

Metric	Units	Final Reported Value		Calculation
		Project	System	
DG (DER) Interconnection equipment	# of units	0	0	N/A
Distributed Gen. Interface	Description	All DG installed is non-dispatchable utility-owned PV that is being metered separately. All project EV chargers are installed behind customer meters. Most interfaces currently limited to measuring data. EV chargers may be remotely deactivated to curtail load.	Non-dispatchable utility-owned DG and EV Chargers. All EV chargers are installed behind customer meters. Most interfaces currently limited to measuring data. EV chargers may be remotely deactivated to curtail load.	N/A
		Project Funded	Cost Share	
DER Interface Control Systems Cost	$	$2,585,472	$2,183,009	Costs associated with installation of the DERM.
Communications Equipment Cost	$	$0	$0	N/A
DER/DG Interconnection Equipment Cost	$	$0	$0	N/A
Renewable DER Cost	$	$668,165	$541,403	Costs associated with installation of the solar PV systems.
Distributed Gen. Equipment Cost	$	$0	$0	N/A
Stationary Electric Storage Equipment Cost	$	$4,017,795	$3,708,112	Costs associated with installation of the battery energy storage system.
PEVs and Charging Stations Cost	$	$71,089	$60,207	Costs associated with installation of the EV charging stations.
Other Costs		$0	$0	N/A

Table 3-158: Build Metrics for KCP&L's Distribution System Assets

Metric	Units	Final Reported Value		Calculation
		Project	System	
Portion of System with SCADA	% Description	100% Distribution SCADA has been deployed to all field devices in the project area.	10.5% The ABB Network Manager (EMS) communicates with 70% of feeder breakers, but only 15% of those have communications capable of supporting Smart Grid functionality.	N/A
Portion of System with Distribution Automation (DA)	% Description	100% DA capabilities are installed on all project circuits.	85% KCP&L has locally automated devices such as capacitors, voltage monitors, faulted circuit indicators, and reclosers across the distribution system. 85% represents an estimate of coverage based on number of circuits with one or more of these devices.	N/A
Automated Feeder Switches	# devices	20	117	Count of installed devices.
Automated Capacitors	# devices	29	2,342	Count of installed devices.
Automated Regulators	# devices	0	3	Count of installed devices.
Feeder Monitors	# devices	0	0	N/A
Remote Fault Indicators	# devices	96	325	Count of installed devices.
Transformer Monitors (line)	# devices	0	0	N/A
Smart Relays	# devices	63	2,277	Count of installed devices.
Fault Current Limiter	# devices	0	0	N/A

Metric	Units	Final Reported Value		Calculation
		Project	System	
SCADA	Description	Distribution SCADA in conjunction with project DMS/OMS, includes a Tropos wireless network to reach devices outside the substation.	ABB Network Manager (EMS) across system plus project Distribution SCADA.	N/A
DA Devices	Description	There is a mix of communicating and automated capacitors, faulted circuit indicators, and reclosers across the project area.	There is a mix of locally automated capacitors, voltage monitors, faulted circuit indicators, and reclosers across distribution system.	N/A
DA Communications Network	Description	Tropos GridCom wireless IP mesh network	Landis+Gyr AMR system and Telemetric/Sensus cellular-based system.	N/A
Fault Location, Isolation and Service Restoration (FLISR)	Yes/No Description	No As part of the project, the DMS enables FLISR across project circuits. This will reduce outages and outage response time, and improve overall system performance.	No As part of the project, the DMS enables FLISR across project circuits. This will reduce outages and outage response time, and improve overall system performance.	N/A

Metric	Units	Final Reported Value		Calculation
		Project	System	
Voltage Optimization	Yes/No Description	Yes As part of the project, the DMS enables voltage optimization across project circuits. This will improve power factor as well as enable voltage conservation.	Yes A Dynamic Voltage Control (DVC) system exists on 203 buses within metropolitan Kansas City. This system is able to dynamically reduce voltage through load tap changers to achieve voltage changes in coordination with locally controlled cap banks.	N/A
Feeder Peak Load Management	Yes/No Description	No As part of the project, the DMS enables dynamic feeder load transfer across project circuits. This will reduce outages on project feeders, reduce stress on critical assets, and improve maintenance.	No System peak loads are curtailed through utilization of the DVC system and existing PCT program operated by Honeywell.	N/A
Microgrids	Yes/No Description	No	No	N/A
Integration with AMI	Yes/No Description	Yes DMS is integrated with project AMI.	Yes DMS is integrated with project AMI.	N/A
Integration with Outage Management System	Yes/No Description	Yes DMS is integrated with project OMS.	Yes DMS is integrated with project OMS.	N/A
Integration with Transmission Management System	Yes/No Description	No	No	N/A
Integration with Distributed Energy Resources	Yes/No Description	No DMS is integrated with project DERM.	No DMS is integrated with project DERM.	N/A

Metric	Units	Final Reported Value		Calculation
		Project	System	
Distribution Management System	Description	DMS consisting of D-SCADA and DNA provided by Siemens and OMS and user interface provided by Intergraph.	DMS consisting of D-SCADA and DNA provided by Siemens and OMS and user interface provided by Intergraph.	N/A
		Project Funded	Cost Share	
Back Office Systems Cost	$	$372,159	$343,106	Costs associated with installation of the back office systems.
Distribution Management System Cost	$	$4,338,858	$3,436,891	Costs associated with installation of the DMS.
Communications Equipment and SCADA Cost	$	$959,422	$885,621	Costs associated with the installation of the communications equipment and SCADA.
Feeder Monitor/Indicator Cost	$	$26,079	$23,876	Costs associated with the installation of the feeder monitors/indicators.
Substation Monitors Cost	$	$1,244,388	$1,141,646	Costs associated with the installation of the substation monitors.
Automated Feeder Switches Cost	$	$690,574	$632,255	Costs associated with the installation of the automated feeder switches.
Capacitor Automation Equipment Cost	$	$72,896	$66,740	Costs associated with the installation of the capacitor automation equipment.
Regulator Automation Equipment Cost	$	$0	$0	N/A
Fault Current Limiter Equipment Cost	$	$0	$0	N/A
Other Costs	$	$377,579	$339,818	KCP&L labor charges across various devices types.

3.5.2 Impact Metrics

Impact Metrics were reported on a semiannual basis as outlined in the MBRP. The list of reported metrics was approved by the DOE and is listed in Appendix A. The final semiannual impact metrics were submitted on October, 31, 2014 for the 6-month period ending September 30, 2014. All submitted impact metrics can be found in Appendix T.

3.5.2.1 Impact Metrics/Benefits Calculations

The following tables list the calculated values for each of the reported impact metrics along with the method used to calculate them.

Table 3-159: Impact Metrics for KCP&L's AMI and Customer Systems

Metric	Units	Final Reported Value		Calculation
		Project	System	
Hourly Customer Electricity Usage: Residential	kWh $/kWh	Reported in a separate file	N/A	Hourly average residential customer load data were calculated by aggregating all Normal AMI meters in residential rate classes in the project area
Hourly Customer Electricity Usage: Commercial	kWh $/kWh	Reported in a separate file	N/A	Hourly average commercial customer load data were calculated by aggregating all Normal AMI meters in commercial rate classes in the project area
Monthly Customer Electricity Usage: Residential	kWh $/kWh	Reported in a separate file	N/A	Total monthly residential customer load data were calculated by aggregating all Normal AMI meters in residential rate classes in the project area
Monthly Customer Electricity Usage: Commercial	kWh $/kWh	Reported in a separate file	N/A	Total monthly residential customer load data were calculated by aggregating all Normal AMI meters in residential rate classes in the project area
Peak Load: Total Amount	MW	49.4753562	N/A	Total maximum hourly MW load for the 6 month period, as determined from hourly aggregation of load data
Peak Load: Residential	MW	26.9865111	N/A	Residential component of total MW load at peak date and time
Peak Load: Commercial	MW	22.4888451	N/A	Commercial component of total MW load at peak date and time
Peak Load: Date and Time	Date/Time	8/25/2014 5:00:00 PM	N/A	Date and time at which the maximum hourly MW load occurred
Peak Load Mix: Direct Load Control Available	MW	N/A	N/A	N/A
Number of Meter Tamper Detections	# identified # confirmed	N/A	N/A	N/A
Meter Operations Cost	$	167,090.10	N/A	AMI operations costs for the 6 month period, including software licenses and hosting services
Truck Rolls Avoided	#	4,043	N/A	Count of avoided truck rolls for on-demand reads, remote disconnects, and remote reconnects as tracked by the RSO.

Metric	Units	Final Reported Value		Calculation
		Project	System	
Meter Operations Vehicle Miles	miles	64,688	N/A	Assuming an average of 16 miles round trip per truck roll based on distance from Dotson service center. (4,043 truck rolls x 16 miles/truck roll = 64,688 miles)
SAIFI	Index	2.331273	N/A	Total number of customer interruptions divided by the total number of customers served in the project area
SAIDI	Index	235.4554	N/A	Total sum of customer interruption durations (in minutes) divided by the total number of customers served in the project area
CAIDI	Index	100.9986	N/A	Total sum of customer interruption durations (in minutes) divided by the total number of customer interruptions
SAIDI and SAIFI: Number of customers	#	13,427	N/A	Count of Normal AMI meters in the project area
Avoided CO_2 Emissions	tons	38.46779733	N/A	8.92 × 10-3 metric tons CO_2/gallon of gasoline (http://www.epa.gov/cleanenergy/energy-resources/refs.html) Assuming 15 miles/gallon ((64,688 miles/15 miles/gallon) * 0.00892 tons CO_2/gallon = 38.46779733 tons)
Avoided Pollutant Emissions (SO_X, NO_X, PM-2.5)	tons	N/A	N/A	N/A
Meter Data Completeness	%	99.27	N/A	Calculated by taking the number of meters in Normal status divided by the number of meters deployed, according to the AHE
Meters Reporting Daily	%	99.22	N/A	Calculated by taking the number of meters with good reads on final reporting day divided by the number of meters deployed, according to the AHE

Table 3-160: Impact Metrics for KCP&L's Distribution Systems

Metric	Units	Final Reported Value		Calculation
		Project	System	
Distribution Feeder or Equipment Overload Incidents: Feeder Line	# incidents Average duration (minutes)	0 0	N/A	No incidents were reported in the project area during the 6 month period, based on a query of the OMS system
Distribution Feeder or Equipment Overload Incidents: Substation Transformer	# incidents Average duration (minutes)	0 0	N/A	No incidents were reported in the project area during the 6 month period, based on a query of the OMS system
Distribution Feeder Load: Aggregated Average Load	MW MVAR	N/A	N/A	N/A
Distribution Feeder Load: Hourly Load Curves	MW MVAR	Reported in a separate file	N/A	Hourly MW data was extracted from the DMAT for each feeder
Deferred Distribution Capacity Investments	$ years	N/A	N/A	N/A
Equipment Failure Incidents: Transformers	# incidents Reasons for failures	0 N/A	N/A	No incidents were reported in the project area during the 6 month period, based on a query of the OMS system
Equipment Failure Incidents: Feeders	# incidents Reasons for failures	3 Failure Wear	N/A	3 incidents of Failure Wear were reported in the project area during the 6 month period, based on a query of the OMS system
Equipment Failure Incidents: Other Distribution Equipment	# incidents Reasons for failures	N/A	N/A	No incidents were reported in the project area during the 6 month period, based on a query of the OMS system N/A
Truck Rolls Avoided	# truck rolls	N/A	N/A	N/A
SAIFI	Index	2.331273	N/A	Total number of customer interruptions divided by the total number of customers served in the project area
SAIDI	Index	235.4554	N/A	Total sum of customer interruption durations (in minutes) divided by the total number of customers served in the project area
CAIDI	Index	100.9986	N/A	Total sum of customer interruption durations (in minutes) divided by the total number of customer interruptions
SAIDI and SAIFI: Number of customers	#	13,427	N/A	Count of Normal AMI meters in the project area

Metric	Units	Final Reported Value		Calculation
		Project	System	
Major Event Information	Event Statistics	N/A	N/A	No major events were reported in the project area during the 6 month period, based on a query of the OMS system
Avoided Distribution Operations Vehicle Miles	miles	N/A	N/A	N/A
Avoided CO_2 Emissions	tons	N/A	N/A	N/A

Table 3-161: Impact Metrics for KCP&L's Storage Systems

Metric	Units	Final Reported Value		Calculation
		Project	System	
Annual Storage Dispatch	kWh	95,864	N/A	Total electricity discharged from the storage system for the 6 month period ending 9/30/14, based on summation of 15-minute interval reads from DMAT.
Average Energy Storage Efficiency	%	69.34	N/A	Roundtrip efficiency for the storage system for the 6 month period ending 9/30/14, based on summation of 15-minute interval reads from DMAT.

3.6 Benefits Analysis

The SGDP operational demonstrations and testing, outlined in the previous section, were performed to not only demonstrate the SmartGrid Functions achievable through end-to-end interoperability, but to also capture and quantify the operational benefits achievable by each of the SmartGrid applications. The KCP&L Demonstration used the DOE-developed Smart Grid Computational Tool (SGCT) and Energy Storage Computational Tool (ESCT) to evaluate the overall costs and benefits of the demonstrated SmartGrid technologies and functions. The results of this benefits analysis are summarized in the following subsections.

3.6.1 Smart Grid Computational Tool Analysis

Using the SGCT, the SGDP team: 1) identified the Smart Grid Assets deployed; 2) identified the Smart Grid Functions that the demonstration would enable; and 3) for each Function, identified the applicable benefit mechanisms. Based on these inputs, the SGCT identified the expected benefits the project could achieve. The SGDP team identified several additional function benefits not identified by the SGCT that it was able to quantify. Table 3-162 identifies the project benefits by Smart Grid Function used in the SGCT analysis. The benefit areas quantified by the project and included in the benefit analysis are highlighted in green. All entry and output screens for the SGCT analysis were captured and can be found in Appendix U.

Table 3-162: SGCT Function Benefit Chart for KCP&L SmartGrid Demonstration Project

Benefits			Smart Grid Functions								
			Delivery						Use	Other	
			Automated Feeder and Line Switching	Automated Islanding and Reconnection	Automated Voltage and VAR Control	Diagnosis & Notification of Equipment Condition	Real-Time Load Measurement & Management	Real-time Load Transfer	Customer Electricity Use Optimization	Storing Electricity for Later Use	Distributed Production of Electricity
Economic	Improved Asset Utilization	Optimized Generator Operation			YES					YES	YES
		Deferred Generation Capacity Investments			YES				YES	YES	YES
		Reduced Ancillary Service Cost									
		Reduced Congestion Cost									
	T&D Capital Savings	Deferred Transmission Capacity Investments									
		Deferred Distribution Capacity Investments			YES		YES			YES	YES
		Reduced Equipment Failures				YES					
	T&D O&M Savings	Reduced T&D Equipment Maintenance Cost									
		Reduced T&D Operations Cost	YES								
		Reduced Meter Reading Cost					YES				
	Theft Reduction	Reduced Electricity Theft					YES				
	Energy Efficiency	Reduced Electricity Losses									
	Electricity Cost Savings	Reduced Electricity Cost			YES				YES	YES	YES
Reliability	Power Interruptions	Reduced Sustained Outages	YES	YES		YES	YES			YES	YES
		Reduced Major Outages		YES			YES	YES			
		Reduced Restoration Cost	YES			YES	YES				
	Power Quality	Reduced Momentary Outages									
		Reduced Sags and Swells									
Environmental	Air Emissions	Reduced CO2 Emissions	YES				YES	YES	YES	YES	YES
		Reduced SOx, NOx, and PM-2.5 Emissions	YES				YES	YES	YES	YES	YES
Security	Energy Security	Reduced Oil Usage (not monetized)	YES				YES				
		Reduced Wide-scale Blackouts									

3.6.1.1 Input Parameters

The SGCT uses two different types of data to calculate benefits, baseline data and project data. All benefit assumptions rely on the calculated difference between baseline and project data at a given point in time. Due to the nature of the SGDP, the benefits analysis for most operational demonstrations quantified most benefits as avoided costs. Using the Mirror inputs capability of the SGCT, the avoided costs were entered into the tool as negative values. Table 3-163 lists the calculated values for each of the SGCT inputs along with the operational tests used to calculate them.

2013 was selected as the Project Start Year as it correlated closely to the project's operational Go-Live date of October 1, 2012. The majority of the benefits quantified by each of the operational demonstration analyses were based on the 2014 data. These computed values are listed in Table 3-163 and were entered as benefits for the years 2014-2017. For 2013, benefits were assumed to be 50% of the 2014 values.

Table 3-163: SGCT Input Parameters

Benefit	Input Name	Operational Test	Op. Test Value	Input Value 2014	Unit
PCM Main Data	Organization Name			KCP&L	-
	Project Name			Smart Grid Demo	-
	NERC Region			SPP	-
	Project Start Year			2013	-
DIM Step 1 Population and Tariff Data	Average Energy Rate-Res	Project Metric		0.10837	$/kWh
	Average Demand Charge-Res	Project Metric		0	$/kW
	Customers Served-Res	Project Impact Metric		12,204	
	Average Energy Rate-Com	Project Metric		.05692	$/kWh
	Average Demand Charge-Com	Project Metric		2.65	$/kW
	Customers Served-Com	Project Impact Metric		1,223	
	Average Energy Rate-Ind	n/a		.05692	$/kWh
	Average Demand Charge-Ind	n/a		2.65	$/kW
	Customers Served-Ind	n/a		0	#
DIM Step 2 Escalation Factors	Population Growth Factor	SGCT SPP Default		0.40	%
	Load Growth Factor	SGCT SPP Default		1.80	%
	Economic Inflation Factor	SGCT SPP Default		2.10	%
	Energy Price Factor	SGCT SPP Default		1.40	%
	Final year of benefits	SGCT SPP Default		2038	%
DIM Step 3 Cost Data Entry	Discount Rate	KCP&L Metric		6.584	%
	Use Custom Cost Schedule	n/a		YES	
	Capital Proj. Total	Project Metric	24,278,592	n/a	$
	Levelized Fixed Charge Rate	Project Metric	14.112	n/a	%
	Annual Capital Fixed Charge	Project Metric	3,426,186	4,111,423	$
	Annual Capital O&M @20%	Project Metric	685,237		
Optimized Generator Operation	Annual Generation Cost (Avoided)	Integrated Volt/VAR	(112,126)	(124,488)	$
		Electric Energy Time Shift (BESS)	(2,963)		
		Distributed Rooftop PV	(9,399)		

Benefit	Input Name	Operational Test	Op. Test Value	Input Value 2014	Unit
Deferred Generation Capacity Investments	Energy Storage Use at Annual Peak Time	Electric Supply Capacity (BESS)	0.8	0.802	MW
		TOU Energy Cost Management (PESS)	.002		
	Distributed Generation Use at Annual Peak Time	Distributed Rooftop PV	.0745	0.0745	MW
	Total Customer Peak Demand (Avoided)	Integrated Volt/VAR	(0.559)	(0.583)	MW
		Home Area Network	0		
		Time of Use Rates	(.024)		
	Price of Capacity at Annual Peak	SGCT Default Value	95,700	95,700	$/MW
Deferred Distribution Capacity Investments	Capital Carrying Charge of Distribution Upgrade	Integrated Volt/VAR	178,471	338,743	$
		T&D Upgrade (BESS)	159,634		
		TOU Energy Cost Management (PESS)	638		
		Real Time Load Transfer	0		
	Distribution Investment Time Deferred	Integrated Volt/VAR	5	5	yrs
		T&D Upgrade (BESS)	5		
		TOU Energy Cost Management (PESS)	5		
		Real Time Load Transfer	0		
Reduced Equipment Failures	Capital Replacement of Failed Equipment	Asset Condition Monitoring	1,250,000	1,250,000	$
	Portion Caused by Lack of Condition Diagnosis	Asset Condition Monitoring	100	100	%
Reduced T&D Operations Cost	Distribution Feeder Switching Operations (Avoided)	Real Time Load Transfer	0	0	$
	Distribution Capacitor Switching Operations (Avoided)	Integrated Volt/VAR	n/a	0	$
	Other Distribution Operations Costs (Avoided)	Auto. Feeder Switching	(901.25)	(901.25)	$
Reduced Meter Reading Cost	Meter Operations Cost (Avoided)	Automated Meter Reading	(63,380)	(167,500)	$
		Remote Connect Disconnect	(104,120)		
Reduced Electricity Theft	Number of Meter Tamper Detections - Residential	Automated Meter Reading	10	10	#
	Number of Meter Tamper Detections - Commercial	n/a	0	0	#
	Number of Meter Tamper Detections - Industrial	n/a	0	0	#
	Average Annual Customer Electricity Usage - Residential	Project Impact Metric	7,982	7,982	kWh
	Average Annual Customer Electricity Usage - Commercial	Project Impact Metric	89,715	89,715	kWh
	Average Annual Customer Electricity Usage - Industrial	Project Impact Metric	0	0	kWh

Benefit	Input Name	Operational Test	Op. Test Value	Input Value 2014	Unit
Reduced Electricity Losses	Distribution Feeder Load	Integrated Volt/VAR	0	0	MVA
	Distribution Losses	Integrated Volt/VAR	0	0	%
		Real Time Load Transfer	0		
	Average Price of Wholesale Energy	2014 SPP DAH Market	.03321	.03321	$/kWh
Reduced Electricity Cost	Total Residential Electricity Cost (Avoided)	Integrated Volt/VAR	(172,072)	(180,073)	$
		TOU Energy Cost Management (PESS)	(495)		
		Historical Interval Usage	0		
		In Home Display	0		
		Home Area Network	0		
		Time of Use Rates	(7,506)		
	Total Comm. Electricity Cost	Integrated Volt/VAR	(101,799)	(101,799)	$
	Total Industrial Electricity Cost	n/a	0	0	$
Reduced Sustained Outages	SAIDI (Baseline)	Auto. Feeder Switching	3.025	3.025	Hrs
	SAIDI (Project)	Auto. Feeder Switching	1.966	1.966	
	Total Residential Customers Served by Impacted Feeders or Lines	Project Impact Metric	12,204	12,204	#
	Total Commercial Cust. Served by Impacted Feeders or Lines	Project Impact Metric	1,223	1,223	#
	Total Industrial Customers Served by Impacted Feeders or Lines	Project Impact Metric	0	0	#
	Outage Time of Major Outage - Commercial	n/a	0	0	hr
	Number of Customers Affected by Major Outage - Commercial	n/a	0	0	#
	Outage Time of Major Outage - Industrial	n/a	0	0	hr
	Number of Customers Affected by Major Outage - Industrial	n/a	0	0	#
Reduced Sustained Outages & Reduced Major Outages	Value of Service - Residential	KCP&L Metric	2.27	2.27	$/kWh
	Value of Service - Commercial	KCP&L Metric	97.30	97.30	$/kWh
	Value of Service - Industrial	SGCT Default Value	17.33	17.33	$/kWh
	Average Hourly Load Not Served During Outage per Customer - Residential	Project Impact Metric	0.91119	0.91112	kW
	Average Hourly Load Not Served During Outage per Customer - Commercial	Project Impact Metric	10.24124	10.24124	kW
	Average Hourly Load Not Served During Outage per Customer - Industrial	Project Impact Metric	0	0	kW
Reduced Restoration Cost	Number of Outage Events (Avoided)	Auto. Feeder Switching	(77)	(77)	# of events
	Restoration Cost per Event	KCP&L Metric	260	260	$/event

Benefit	Input Name	Operational Test	Op. Test Value	Input Value 2014	Unit
Reduced CO_2 Emissions, Reduced SOx, NOx, and PM-2.5 Emissions, & Reduced Oil Usage (not monetized)	Number of Feeder Switching or Maintenance Operations Completed (Avoided)	Auto. Feeder Switching	(77)	(77)	# of events
	Average Miles Traveled per Switching or Maintenance Operation	KCP&L Metric	20	20	miles/ event
	Average Fuel Efficiency for Feeder Service Vehicle	KCP&L Metric	6.33	6.33	miles/ gallon
	Number of Meter Reading Operations (Avoided)	Automated Meter Reading	(3,169)	(8,375)	# of events
		Remote Connect Disconnect	(5,206)		
	Average Miles Traveled per Meter Read	KCP&L Metric	2.2	2.2	miles/ event
	Average Fuel Efficiency for Real-Time Load Measurement/ Management Service Vehicle	KCP&L Metric	11.83	11.83	miles/ gallon
	kWh of Electricity Consumed by PEVs	PEV Charging	28,586	28,586	kWh
	Electricity to Fuel Conversion Factor	SGCT Default Value	.13	.13	gallons/ kWh
Reduced CO_2 Emissions	CO_2 Emissions per Gallon of Fuel	SGCT Default Value	.0097	.0097	tons/ gallon
	CO_2 Emissions (Avoided)	Distributed Rooftop PV	(221.8)	(3,259.5)	tons
		Integrated Volt/VAR	(3,037.7)		
	Value of CO_2	SGCT Default Value	20	20	\$/ton
Reduced SOx, NOx, and PM-2.5 Emissions	SOx Emissions per Gallon of Gas	SGCT Default Value	0.0000002237691 9593	0.0000002237691 9593	tons/ gallon
	NOx Emissions per Gallon of Gas	SGCT Default Value	0.00017	0.00017	tons/ gallon
	PM-2.5 per Gallon of Gas	SGCT Default Value	0	0	tons/ gallon
	SOx Emissions (Avoided)	Distributed Rooftop PV	(0.314)	(4.621)	tons
		Integrated Volt/VAR	(4.307)		
	NOx Emissions (Avoided)	Distributed Rooftop PV	(0.236)	(3.475)	tons
		Integrated Volt/VAR	(3.239)		
	PM-2.5 Emissions (Avoided)	Distributed Rooftop PV	(0.00252)	(0.03703)	tons
		Integrated Volt/VAR	(0.03451)		
	Value of SOx	SGCT Default Value	520	520	\$/ton
	Value of NOx	SGCT Default Value	3,000	3,000	\$/ton
	Value of PM-2.5	SGCT Default Value	36,000	36,000	\$/ton

3.6.1.2 Results/Tool Output

The following tables and figures provide a summary of the SGCT benefits analysis for the SGDP. Additional analysis results can be found in Appendix U. Table 3-164 and Figure 3-231 present a summary of the cumulative gross benefits of the SGCT benefits analysis.

Table 3-164: SGCT Cumulative Gross Benefits Summary

Cumulative Gross Benefits 2013 - 2040		
Economic	$	24,629,720
Reliability	$	53,452,464
Environmental	$	2,552,834
Security	$	-
Total	**$**	**80,635,019**

Figure 3-231: SGCT Cumulative Gross Benefits Summary

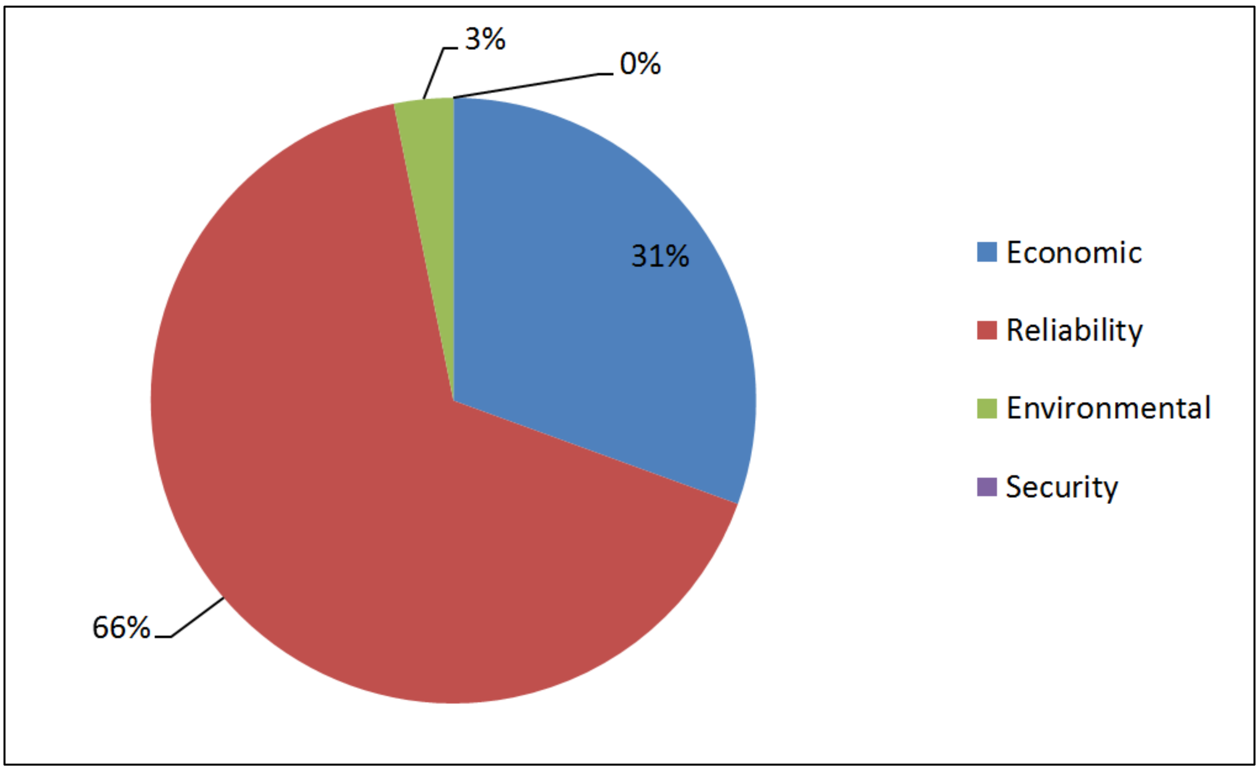


Table 3-164 and Figure 3-232 present a summary of the cumulative economic benefits of the SGCT benefits analysis.

Table 3-165: SGCT Cumulative Economics Benefits Summary

Cumulative Economic Benefits 2013 - 2040		
Improved Asset Utilization	$	9,271,353
T&D Capital Savings	$	1,347,714
T&D O&M Savings	$	5,395,439
Reduced Electricity Theft	$	101,966
Reduced Electricity Losses	$	-
Reduced Electricity Costs	$	8,513,248
Total	**$**	**24,629,720**

Figure 3-232: SGCT Cumulative Economic Benefits Summary

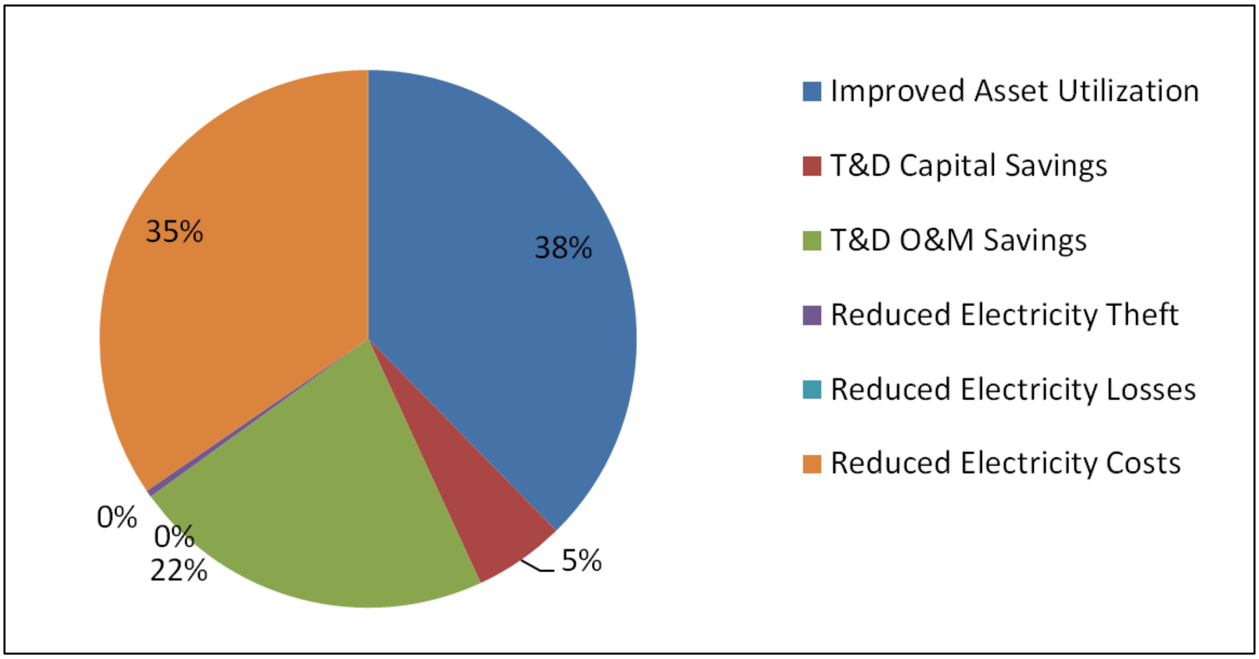


Figure 3-233 illustrates the annual PV benefits, costs, and net benefits results for the SGCT analysis.

Figure 3-233: SGCT Annual PV Benefits, Costs, and Net Benefits

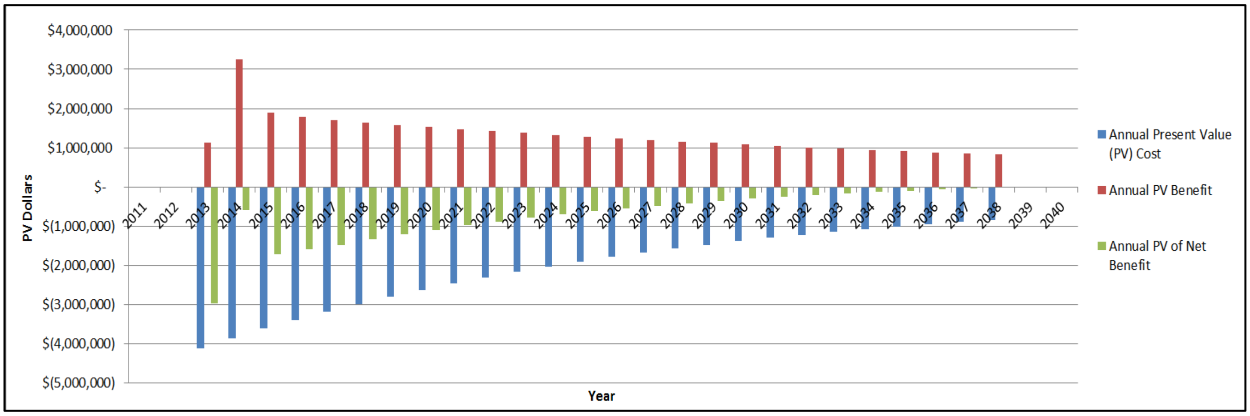
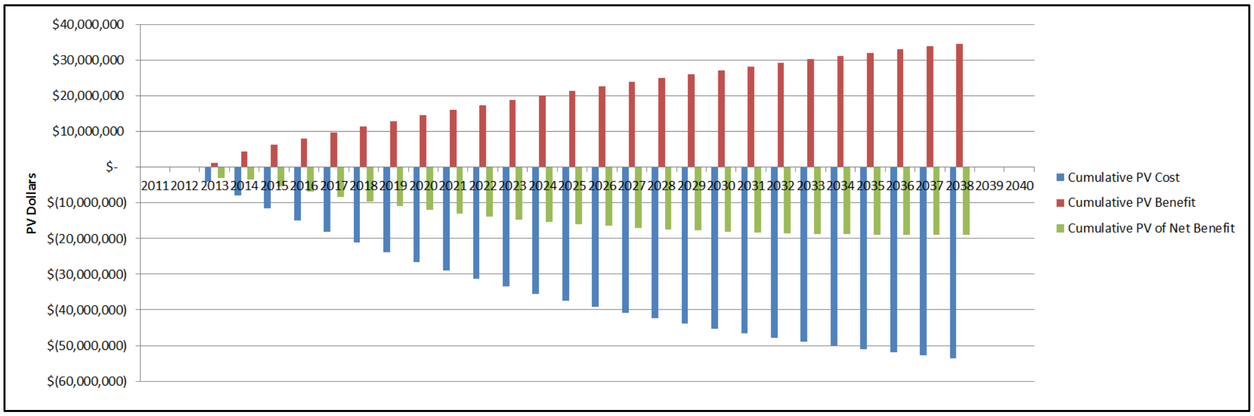


Figure 3-234 illustrates the cumulative PV benefits, costs, and net benefits results for the SGCT analysis.

Figure 3-234: SGCT Cumulative PV Benefits, Costs, and Net Benefits



3.6.1.3 Benefits Summary

The SGCT benefits analysis was performed from the holistic perspective including utility, customer, and societal benefits. Present value benefits of $1.14 million were quantified in economic (31%), reliability (66%), and environmental (3%) benefits. But, the overall net present value of the project remained a net cost to the utility of nearly $3 million. However, it must be noted that several of the SGDP systems (AMI, MDM, and some SmartDistribution components) were capable of supporting much larger smart grid deployments with minimal incremental cost. For these systems, a larger deployment would result in a lower cost per field unit deployed result in a more favorable analysis.

3.6.2 BESS Energy Storage Computational Tool Analysis

Using the ESCT, the project team input the energy storage asset information, grid location, market, and ownership for the BESS. Based on these inputs, the ESCT identified the expected benefits the BESS could achieve. Table 3-166 identifies the expected benefits by Energy Storage Application. The benefit areas quantified by the project and included in the benefit analysis are highlighted in green. To achieve the desired ESCT Application/Benefit combination for this specific BESS configuration required the following ESCT data entry adjustments.

- Location was set to Generation & Transmission instead of Distribution
- Deferred Distribution Investments were entered as Deferred Transmission Investments

All entry and output screens for this ESCT analysis were captured and can be found in Appendix V.

Table 3-166: ESCT Application-Benefit Matrix for KCP&L BESS Analysis

Location	Market	Owner	Application	Optimized Generator Operation	Deferred Generation Capacity Investments	Deferred Transmission Investments	Deferred Distribution Investments	Reduced Electricity Losses	Reduced Electricity Cost	Reduced CO2 Emissions	Reduced SOx Emissions	Reduced NOx Emissions	Reduced PM Emissions
Distribution	Regulated	Utility	Electric Energy Time-shift	0	0		0	0					
Distribution	Regulated	Utility	Electric Supply Capacity										
Distribution	Regulated	Utility	Transmission & Distribution (T&D) Upgrade Deferral	0	0			0		0	0	0	0

3.6.2.1 Input Parameters

Table 3-167 lists the data values for each of the ESCT inputs along with the operational tests used to calculate them.

Table 3-167: BESS – ESCT Input Parameters

Benefit	Input Name	Operational Test	Project Value	Unit
Energy Storage Location	Location	ESCT Setup	Gen & Trans	-
	Market	ESCT Setup	Regulated	-
	Owner	ESCT Setup	Utility	-
	Storage Technology	ESCT Setup	Battery-Li Ion	-
Energy Storage System Parameters	Nameplate Power Output	Project Metric	1,000	kW
	Nameplate ES Capacity	Project Metric	2,000	kWh
	ES Response Time	ESCT Default Value	0.001	seconds
	ES Round Trip Efficiency	Project Metric	75.06	%
	Nameplate Life Cycles	ESCT Default Value	4500	cycles
	Yr. over Yr. Demand Growth	SGCT Default Value	1.8	%
	ES Reactive Power Capability	Project Metric	Yes	-
	NERC Region	Project Metric	SPP North	-

Benefit	Input Name	Operational Test	Project Value	Unit
Energy Storage Cost Parameters	Expected Lifetime	Project Metric	10	yrs
	Inflation Rate	SGCT Default Value	2.1	%
	Discount Rate	KCP&L Metric	6.584	%
	Installed Cost	ESCT Default Value	2,950,000	$
	Fixed Charge Rate	KCP&L Metric	17.441	%
	Operating & Maintenance	ESCT Default Value	21,000	$/yr
	Expected Decommissioning	ESCT Default Value	147,500	$
	Initial Year of Analysis	Project Metric	2013	year
Reduced Electricity Cost	Total Energy Discharged for Energy Time-Shift	Energy Time Shift	266.68	MWh
	Average Variable Peak Generation Costs	Energy Time Shift	41.46	$/MWh
	Average Variable Off-Peak Generation Costs	Energy Time Shift	22.78	$/MWh
	CO2 Emissions Factor for Generation on the Margin	ESCT Default Value	1,151	lbs/MWh
	CO2 Emissions Factor for Base Generation	ESCT Default Value	2,251	lbs/MWh
	SOx Emissions Factor for Generation on the Margin	ESCT Default Value	0.012	lbs/MWh
	SOx Emissions Factor for Base Generation	ESCT Default Value	6.67	lbs/MWh
	NOx Emissions Factor for Generation on the Margin	ESCT Default Value	1.41	lbs/MWh
	NOx Emissions Factor for Base Generation	ESCT Default Value	3.73	lbs/MWh
	PM Emissions Factor for Generation on the Margin	ESCT Default Value	0.040	lbs/MWh
	PM Emissions Factor for Base Generation	ESCT Default Value	0.200	lbs/MWh
	Value of CO2	ESCT Default Value	20	$/ton
	Value of SOx	ESCT Default Value	520	$/ton
	Value of NOx	ESCT Default Value	3,000	$/ton
	Value of PM	ESCT Default Value	36,000	$/ton
Deferred Generation Capacity Investment	Generation Capacity Deferred	Electricity Supply Capacity	0.8	MW
	Capital Cost of Deferred Generation Capacity	ESCT Default Value	1,227,000	$/MW
	Yearly O&M Costs of Deferred Generation Capacity	ESCT Default Value	14,000	$/MW-year
	Annual Fixed Charge Rate for Generation Capital Investment	KCP&L Metric	10.470	%
	Initial Year of Generation Deferral	Electricity Supply Capacity	2014	year
	Final year of Generation Deferral	Electricity Supply Capacity	2022	year
Transmission and Distribution Upgrade Deferral	Distribution Capacity Deferred	T&D Upgrade Deferral	500	kVA
	Annual Fixed Charge Rate for Distribution Capital Investment	KCP&L Metric	10.470	%
	Capital Cost of Deferred Distribution Capacity	T&D Upgrade Deferral	319.26	$/kVA
	Yearly O&M Costs of Deferred Distribution Capacity	KCP&L Metric	0	$/year
	Initial Year of Distribution Deferral	T&D Upgrade Deferral	2014	year
	Final year of Distribution Deferral	T&D Upgrade Deferral	2022	year

3.6.2.2 Results/Tool Output

The following tables and figures provide a summary of the ESCT benefits analysis for the BESS. Additional analysis results can be found in Appendix V. Table 3-168 contains a summary of the ESCT benefits analysis for the BESS.

Table 3-168: BESS – ESCT Benefits Summary

Cumulative Gross Benefits over the Deployment Period			Lifetime Benefit per kW of Energy Storage Installed	
Arbitrage Revenue	$	-	$	-
Capacity Market Revenue	$	-	$	-
Ancillary Services Revenue	$	-	$	-
Optimized Generator Operation (Non-Utility Merchant)	$	-	$	-
Optimized Generator Operation (Utility/Ratepayer)	$	-	$	-
Deferred Generation Capacity Investments	$	106,500	$	107
Reduced Congestion Costs (Non-Utility Merchant)	$	-	$	-
Reduced Congestion Costs (Utility/Ratepayer)	$	-	$	-
Deferred Transmission Investments	$	15,600	$	16
Deferred Distribution Investments	$	-	$	-
Reduced Electricity Losses	$	-	$	-
Reduced Electricity Cost (Consumer)	$	-	$	-
Reduced Electricity Cost (Utility/Ratepayer)	$	38,400	$	38
Reduced Outages (Consumer)	$	-	$	-
Reduced Outages (Utility/Ratepayer)	$	-	$	-
Improved Power Quality	$	-	$	-
Reduced Emissions	$	-	$	-
Total Gross Benefit	**$**	**160,500**	**$**	**161**

Figure 3-235 summarizes the cumulative BESS benefits by benefit area.

Figure 3-235: BESS–ESCT Benefit Contribution Summary

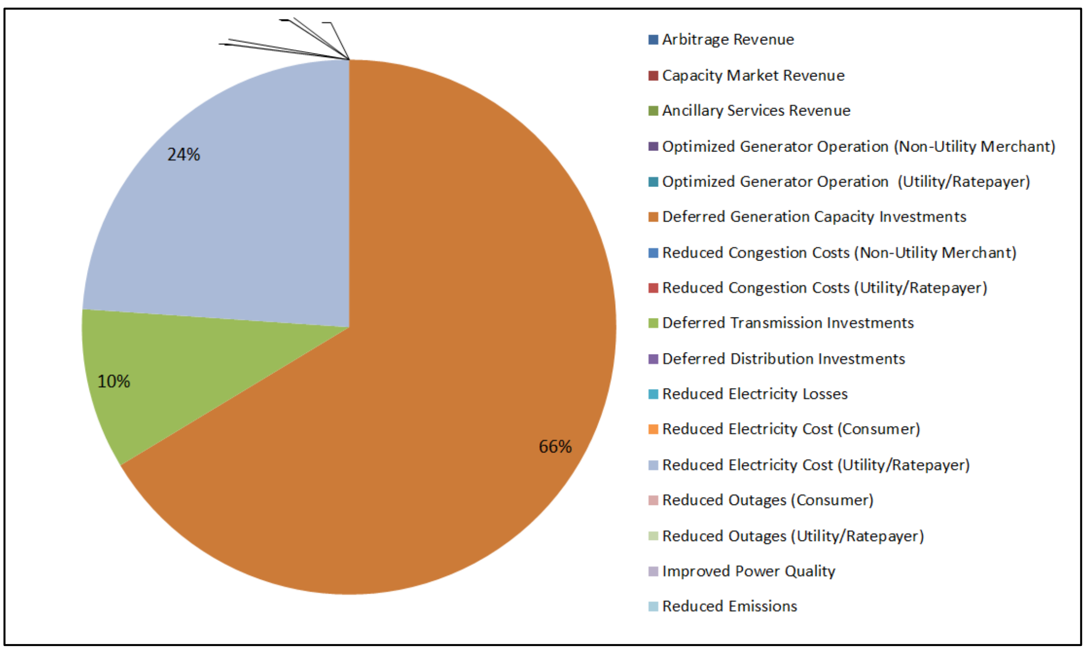


Figure 3-236 illustrates the annual benefits, costs, and net benefits results for the BESS analysis.

Figure 3-236: BESS Annual Benefits, Costs, and Net Benefits

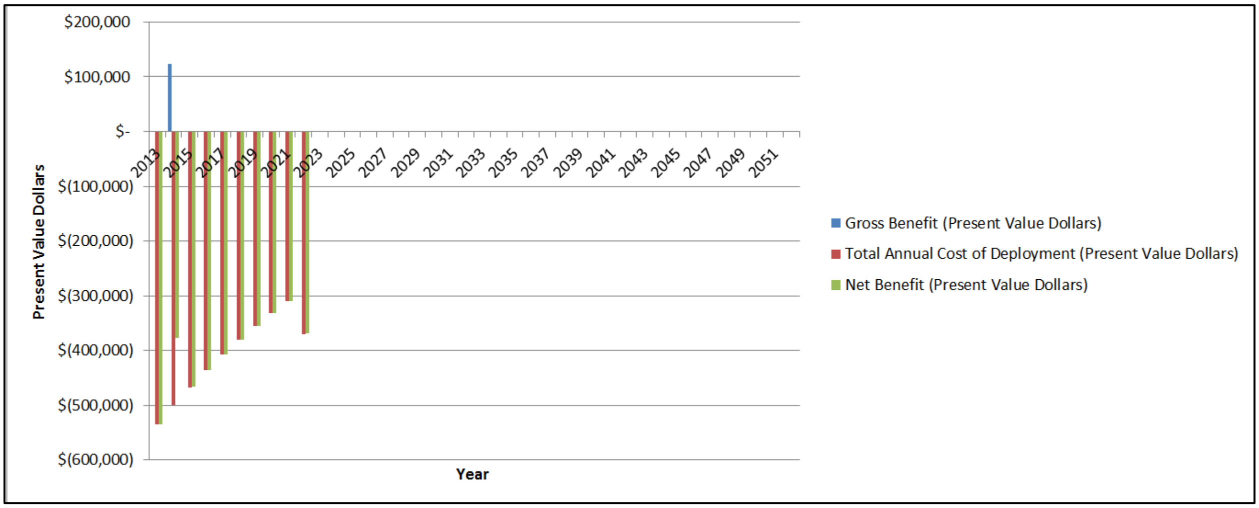
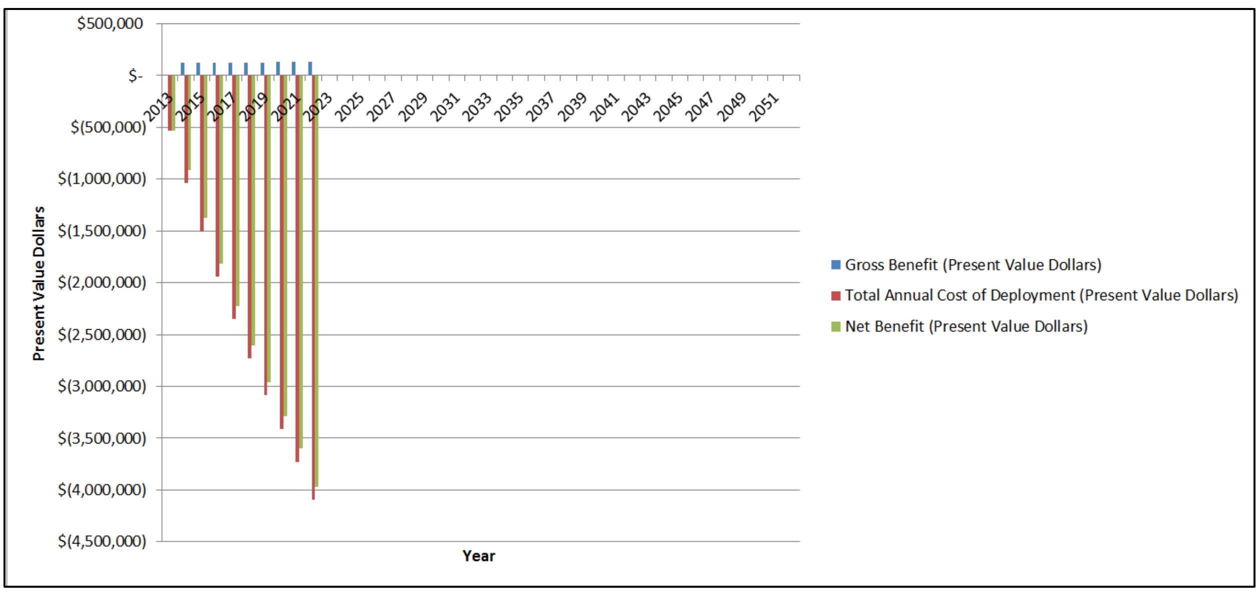


Figure 3-237 illustrates the cumulative benefits, costs, and net benefits results for the BESS analysis.

Figure 3-237: BESS Cumulative Benefits, Costs, and Net Benefits



3.6.2.3 Benefits Summary

The BESS ESCT benefits analysis was performed from the utility perspective. Utility present value benefits of $160,500 were quantified from deferred generation capacity investments (66%), deferred distribution investments (10%) and reduced electricity costs (14%). But, the overall net present value of the BESS remained a net cost to the utility of nearly $4 million. While it may be possible for the utility to achieve increased benefits through T&D efficiencies, the most significant components in determining the economic viability of a BESS for the utility are the upfront installed cost of the unit and the ability to derive additional benefit streams from wholesale ancillary service markets.

3.6.3 PESS Energy Storage Computational Tool Analysis

Using the ESCT, the SGDP team input the energy storage asset information, grid location, market, and ownership for the PESS. Based on these inputs, the ESCT identified the expected benefits the PESS could achieve. Table 3-169 identifies the expected benefits by Energy Storage Application. The benefit areas quantified by the project and included in the benefit analysis are highlighted in green. All entry and output screens for this ESCT analysis were captured and can be found in Appendix W.

Table 3-169: ESCT Application-Benefit Matrix for KCP&L PESS Analysis

Location	Market	Owner	Application	Optimized Generator Operation	Deferred Generation Capacity Investments	Deferred Transmission Investments	Deferred Distribution Investments	Reduced Electricity Losses	Reduced Electricity Cost (Consumer)	Reduced Outages (Consumer)	Reduced CO2 Emissions	Reduced SOx Emissions	Reduced NOx Emissions	Reduced PM Emissions
End-User	Regulated	End-User	Time-of-use (TOU) Energy Cost Management											
End-User	Regulated	End-User	Electric Service Reliability											
End-User	Regulated	End-User	Renewable Energy Time Shift											

3.6.3.1 Input Parameters

Table 3-170 lists the data values for each of the ESCT inputs along with the operational tests used to calculate them.

Table 3-170: PESS – ESCT Input Parameters

Benefit	Input Name	Operational Test	Project Value	Unit
Energy Storage Location	Location	ESCT Setup	End User	-
	Market	ESCT Setup	Regulated	-
	Owner	ESCT Setup	End User	-
	Storage Technology	ESCT Setup	Battery-Li Ion	-
Energy Storage System Parameters	Nameplate Power Output	Project Metric	6	kW
	Nameplate ES Capacity	Project Metric	11.7	kWh
	ES Response Time	ESCT Default Value	0.005	seconds
	ES Round Trip Efficiency	Project Metric	86.45	%
	Nameplate Life Cycles	ESCT Default Value	5000	cycles
	Yr. over Yr. Demand Growth	SGCT Default Value	1.8	%
	ES Reactive Power Capability	Project Metric	No	-
	NERC Region	Project Metric	SPP North	-
Energy Storage Cost Parameters	Expected Lifetime	Project Metric	10	yrs
	Inflation Rate	SGCT Default Value	2.1	%
	Discount Rate	ESCT Default Value	5.0	%
	Installed Cost	ESCT Default Value	24,000	$
	Fixed Charge Rate	ESCT Default Value	15.0	%
	Operating & Maintenance	ESCT Default Value	126	$/yr
	Expected Decommissioning	ESCT Default Value	885	$
	Initial Year of Analysis	Project Metric	2014	year

Benefit	Input Name	Operational Test	Project Value	Unit
TOU Energy Cost Management	Average On-Peak Price of Electricity	KCP&L Metric	41.46	$/MWh
	CO2 Emissions Factor for Generation on the Margin	ESCT Default Value	1,151	lbs/MWh
	SOx Emissions Factor for Generation on the Margin	ESCT Default Value	0.012	lbs/MWh
	NOx Emissions Factor for Generation on the Margin	ESCT Default Value	1.41	lbs/MWh
	PM Emissions Factor for Generation on the Margin	ESCT Default Value	0.040	lbs/MWh
	Value of CO2	ESCT Default Value	20	$/ton
	Value of SOx	ESCT Default Value	520	$/ton
	Value of NOx	ESCT Default Value	3,000	$/ton
	Value of PM	ESCT Default Value	36,000	$/ton
	Total Energy Discharged for TOU Energy Cost Management	TOU Energy Cost Management	2.913	MWh
	Average On-Peak Retail Price of Electricity	TOU Energy Cost Management	200.45	$/MWh
	Average Off-Peak Retail Price of Electricity	TOU Energy Cost Management	26.26	$/MWh
Electric Service Reliability	Outage Minutes Avoided by Residential Customers	Elec. Service Reliability	475.91	minutes
	Outage Minutes Avoided by Commercial Customers	n/a	0	minutes
	Outage Minutes Avoided by Industrial Customers	n/a	0	minutes
	Average Hourly Residential Load Not Served During Outage	Elec. Service Reliability	1.178	kW
	Average Hourly Commercial Load Not Served During Outage	n/a	0	kW
	Average Hourly Industrial Load Not Served During Outage	n/a	0	kW
	Residential VOS	Elec. Service Reliability	2.27	$/kWh
	Commercial VOS	n/a	0	$/kWh
	Industrial VOS	n/a	0	$/kWh
Renewable Energy Time Shift	Total Renewable Energy Discharged for Energy Time-Shift	Renewable Energy Time Shift	0	MWh

3.6.3.2 Results/Tool Output

The following tables and figures provide a summary of the ESCT benefits analysis for the PESS. Additional analysis results can be found in Appendix W. Table 3-171 contains a summary of the ESCT benefits analysis for the PESS.

Table 3-171: PESS – ESCT Benefits Summary

Cumulative Gross Benefits over the Deployment Period (Present Value)		Lifetime Benefit per kW of Energy Storage Installed
Arbitrage Revenue	$ -	$ -
Capacity Market Revenue	$ -	$ -
Ancillary Services Revenue	$ -	$ -
Optimized Generator Operation (Non-Utility Merchant)	$ -	$ -
Optimized Generator Operation (Utility/Ratepayer)	$ -	$ -
Deferred Generation Capacity Investments	$ -	$ -
Reduced Congestion Costs (Non-Utility Merchant)	$ -	$ -
Reduced Congestion Costs (Utility/Ratepayer)	$ -	$ -
Deferred Transmission Investments	$ -	$ -
Deferred Distribution Investments	$ -	$ -
Reduced Electricity Losses	$ -	$ -
Reduced Electricity Cost (Consumer)	$ 4,200	$ 700
Reduced Electricity Cost (Utility/Ratepayer)	$ -	$ -
Reduced Outages (Consumer)	$ 200	$ 33
Reduced Outages (Utility/Ratepayer)	$ -	$ -
Improved Power Quality	$ -	$ -
Reduced Emissions	$ -	$ -
Total Gross Benefit	**$ 4,400**	**$ 733**

Figure 3-238 summarizes the cumulative PESS benefits by benefit area.

Figure 3-238: PESS–ESCT Benefit Contribution Summary

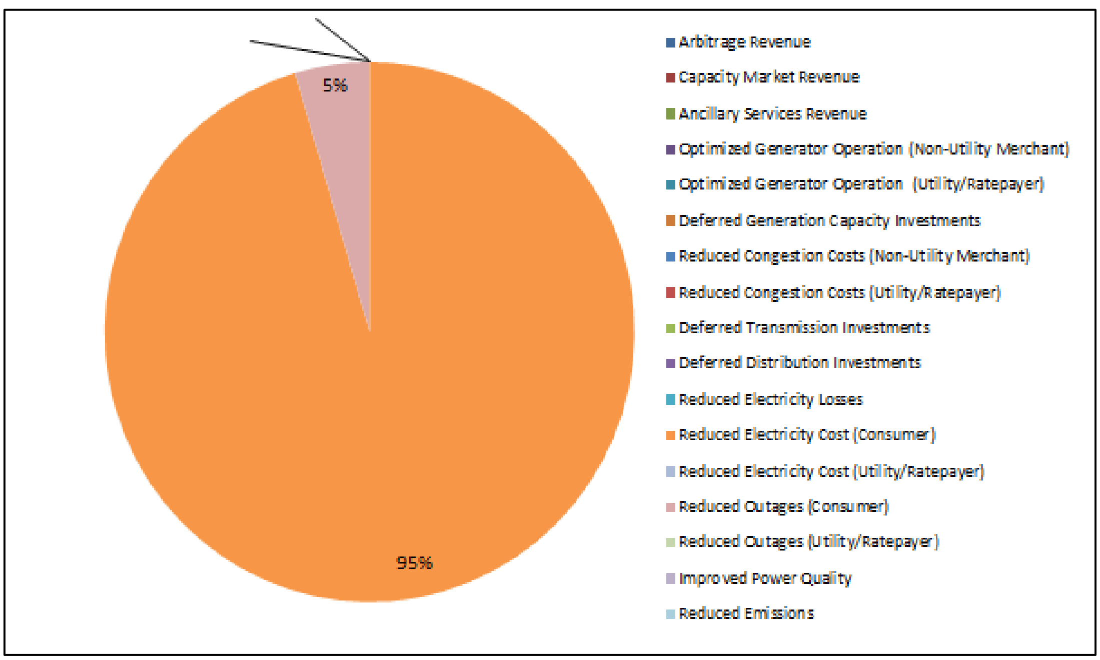


Figure 3-239 illustrates the annual benefits, costs, and net benefits results for the PESS analysis.

Figure 3-239: PESS Annual Benefits, Costs, and Net Benefits

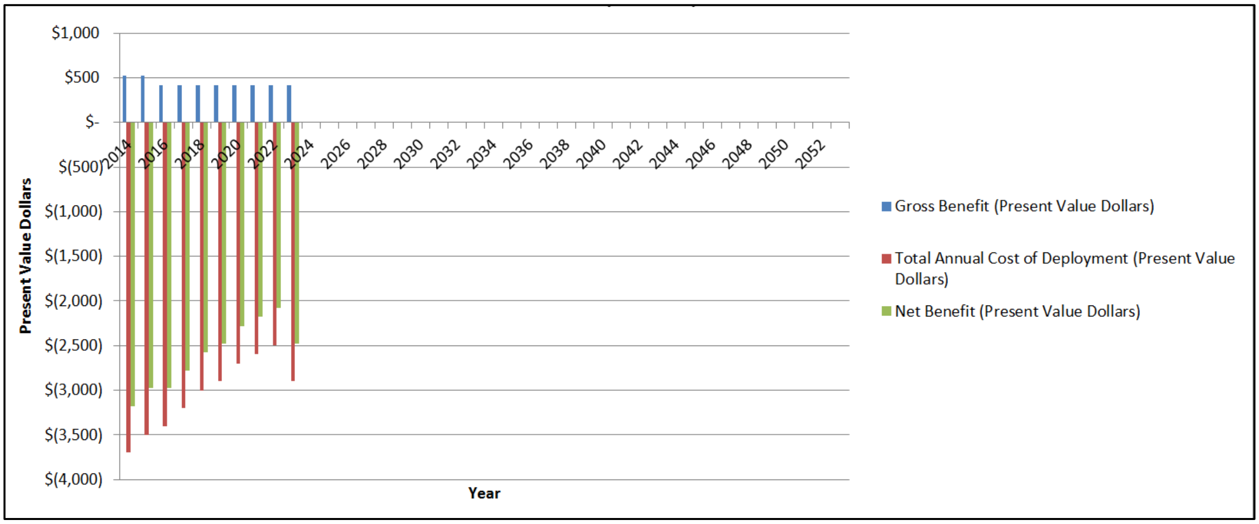
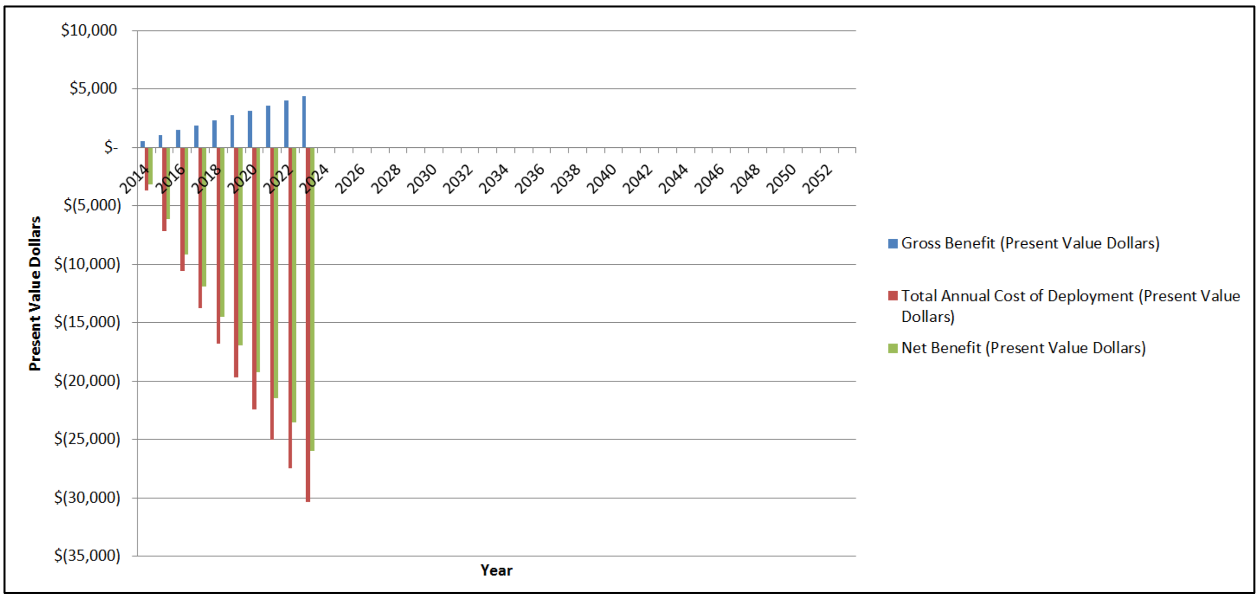


Figure 3-240 illustrates the cumulative benefits, costs, and net benefits results for the PESS analysis.

Figure 3-240: PESS Cumulative Benefits, Costs, and Net Benefits



3.6.3.3 Benefits Summary

The PESS ESCT benefits analysis was performed from the consumer perspective. Consumer benefits were quantified for reduced electricity costs ($4,200) and reduced outages ($200) but, the overall net present value of the PESS remained a net cost to the consumer of $26,000. While it may be possible for the consumer to achieve increased benefits through participation in utility cost sharing or DR programs, the most significant components in determining the economic viability of a PESS for the customer are the upfront installed cost of the unit and the value of outage avoidance perceived by the customer.

4 CONCLUSIONS

The primary objectives of the KCP&L SmartGrid Demonstration Project (SGDP) were twofold: (a) to demonstrate, test, and report on the feasibility of combining, integrating, and applying existing and emerging smart grid technologies and solutions to build innovative smart grid solutions, and (b) to demonstrate, measure, and report on the costs, benefits, and business model viability of the demonstrated solutions. KCP&L has gained valuable knowledge and experience in the implementation and performance of these technologies and systems, as well as insights into the operational, consumer, environmental, and societal benefits that can be achieved. This section summarizes the project's major findings, key takeaways, and implications for future implementation of smart grid technologies at KCP&L and beyond.

4.1 Smart Grid Demonstration Benefits Summary

Throughout the Operational Demonstrations KCP&L identified and quantified, where possible, benefits resulting from deployments of smart grid technologies and implementations of specific smart grid functions. The benefits identified will be instrumental in justifying future enterprise deployments of such smart grid technologies and functions.

4.1.1 SmartMetering Benefits

SmartMetering benefits identified during the conduct of the SGDP include:

- The AMI system established a daily register read performance rate of 99% and provided a more consistent performance throughout the year as compared to the legacy AMR system. On average, AMI performed 2 percentage points better than the AMR system, requiring fewer manual billing reads.
- The AMI infrastructure significantly outperformed the legacy AMR system for completeness of interval data, delivering 99.96% of interval usage data.
- The AMI system significantly outperformed the legacy AMR system by delivering "Power Outage" alerts from 90% of the outaged meters and "Power Restore" alerts from 95% of restored meters, typically within 15 minutes.
- SmartMeters with remote disconnect/reconnect capability significantly reduced the number of truck rolls and labor required for these functions.
- SmartMeter can be programmed to provide a vast number of event notifications, alerts, and alarms. Alerts like "Fatal Error" and "Tamper Detected" were used to generate service orders, speeding up problem detection and resolution.
- Alerts like "Under/Over Voltage" and functions like on-demand voltage reading can be used to support grid operations.
- While not quantified, the MDM demonstrated significant integration benefits by establishing a central meter data repository and acting as the integration point for communications with AMI meters.

4.1.2 SmartEnd-Use Benefits

SmartEnd-Use benefits identified during the conduct of the SGDP include:

- 53% of survey respondents said the Home Energy Management Portal (HEMP) helped them understand more about their electricity usage, how to reduce usage, and how to save money.

- 45% of survey respondents agreed that the HEMP influenced their decisions to take steps to save energy at home over the previous 12 months.
- 85% of survey respondents reported that the daily Estimated Bill feature provided by the HEMP and In-Home Display (IHD) was useful. Many said that this was the feature that provided the most value.
- TOU participants, on average, reduced their On-Peak energy consumption by approximately 10% and saved annually an average of $68 over the 4 month summer rate period.

4.1.3 SmartDistribution Benefits

SmartDistribution benefits identified during the conduct of the SGDP include:

- While not quantified, the DMS and D-SCADA provided grid operators with improved visibility and operational control of the distribution grid.
- While not all benefits were quantified, the DMS and OMS functions provided grid operators with improved capabilities for outage and restoration detection.
- The CVR voltage regulation function was implemented with an average voltage reduction of 2%, resulting in a 1.6% reduction in delivered energy.
- The DVC voltage reduction function was implemented during peak periods and led to an average voltage reduction of 1.6%, resulting in a 1.13% reduction in kW demand.
- The VVC function provided a more stable voltage profile compared to that of the individual, locally controlled capacitor banks.
- Mid-circuit reclosers with fast-trip protection reduced the number of transformer level outages by an estimated 33%, which is enough to prevent 77 truck rolls and 571,600 customer outage minutes.
- FISR and automated switching reduced the number of customers affected by feeder-level outages by an estimated 73.5%, enough to reduce the resulting customer outage minutes by 74% for a savings of over 767,000 customer interruption minutes.
- The combination of FISR and recloser fast-trips provided a 35% reduction in SAIDI for the customers in the study area.
- Asset condition monitoring detected an internal arc in a newly installed substation power transformer, avoiding the loss of a $1.25 million dollar asset.
- While not quantified, the substation HMI provided operations personnel with improved visibility and insight to substation conditions when working within the substation.

4.1.4 SmartGeneration Benefits

SmartGeneration benefits identified during the conduct of the SGDP include:

- While not quantified, the DMS/DERM system integration provided grid operators with the ability to call geographically constrained load reduction events.
- While not quantified, the DERM system provided significant operational benefits in its ability to manage all DR and DER assets and load reduction events.
- Each 1.0 kW of grid-connected rooftop solar generation produced 1,396 kWh annually and reduced the KCP&L 2014 system peak load in August by 0.42 kW.

- The 1.0 MWh BESS could discharge 266 MWh of stored energy annually for energy time shifting. Based on the 2014 SPP Day Ahead Energy Market, this produced approximately $3,000 savings.
- The 1.0 MWh BESS could discharge 0.8 MWh during the system peak hour, thus contributing a 0.8 MW reduction to system peak.
- The 1.0 MWh BESS could discharge 0.8 MWh during the distribution peak load periods, thus providing load reduction of 200 kW to 500 kW at the distribution substation or circuit level. Analysis showed that to provide effective generation or distribution capacity deferral, a BESS should be configured with 4 MWh to 5 MWh of storage for each MW of capacity.
- While not quantified, it was demonstrated that the BESS could island a portion of a distribution circuit and sustain power to customers during an outage to the grid supply.
- The 11.7 kW PESS, when operated for TOU Energy Cost Savings, could discharge 2,900 kWh of stored energy annually during On-Peak periods, potentially saving the customer $638.
- The On-Peak discharge of the PESS resulted in reduction of at least 2 kW in customer peak load, providing the utility the equivalent potential generation and distribution capacity deferral benefits.
- The PESS, when operated for Renewable Energy Time Shift, could store solar energy that was generated Off-Peak and release 2,900 kWh of stored energy annually during On-Peak periods, potentially saving the customer $255.
- The PESS provides the customer with significant benefits from improved electric service reliability by providing power to critical loads and sustaining the solar power generation operation during all but the most extensive power outage events.
- Public EV charging provided increased kWh energy sales of approximately 7 kW per charge. Even more significant, each charge avoided the consumption of approximately 1 gallon of gasoline.

4.2 Lessons Learned and Best Practices

This section describes Lessons Learned for all demonstrated technologies. Others may find benefit from issues and solutions that KCP&L encountered, mitigated, or resolved. Lessons Learned are provided for General Project Execution, Interoperability, Cybersecurity, Education & Outreach, and the SGDP technology components. More detailed explanations of these Lessons Learned are included in Section 2 and Section 3. The most significant highlights are listed below.

4.2.1 General Project Execution Lessons Learned

General Project Execution Lessons Learned during the conduct of the SGDP include:

- When staffing for a project, consider dedicating resources specifically toward the project rather than using a number of employees in part-time capacities. Enterprisewide issues will typically take precedence, so it can be difficult to get the focused attention necessary to complete a project.
- When projects utilize third-party system integrators or contract resources, it is imperative that an effective knowledge transfer and plan for system training be put into place to ensure that the permanent utility team members will be able to fully support the system once the external resources have rolled off the project.
- Upon implementation of a project, business users of new systems need to be encouraged to actively use the new systems, even if their enterprisewide, legacy systems remain operational.
- The SGDP lab and testing environments were beneficial and should be incorporated into any future smart grid technology deployments.

4.2.2 Interoperability Lessons Learned

Interoperability Lessons Learned during the conduct of the SGDP include:

- The standards creation process is slow and tedious. If a standard isn't complete and approved, it may not be feasible to use, as vendors will have to make assumptions, perform custom development, and create extensions. One potential solution is to have all project vendors develop to a common working version of the standard.
- Standards creation isn't sufficient to ensure interoperability; rather, specific application profiles are necessary to minimize some of the ambiguity associated with a standard.
- Even with standard application profiles, there is room for interpretation to facilitate interoperability; there is a need to establish industry testing bodies to ensure consistency in the certification process across vendors.
- Since standards and application profiles don't typically provide complete plug-and-play interoperability between vendors, an ESB can greatly assist in message transformations.
- Careful attention should be devoted to the process for model migration. While only one back office system should be the system of record for the utility data model, the information contained within the back office system ultimately is shared among multiple other systems. Because of such informational complexity, the migration process itself should be as efficient, effective, timely, and accurate as possible. A streamlined migration process can enable the model to be updated frequently.

- Manufacturers of field devices can be slow to adopt new communication technologies. Even if a standard is fully vetted, the time to develop, test, and bring the devices to market is quite long. Utilities need to push vendors to expedite adoption of new communications technologies, especially Internet Protocol (IP).
- Time synchronization between systems and devices is imperative for smart grid deployments to function as desired. Regardless of how a utility chooses to source time (satellite clocks, network time, devices, etc.), it is critical that all time is stored and exchanged in Coordinated Universal Time (UTC) format.
- To ensure stability for all back office systems that facilitate smart grid applications, a holistic monitoring system is necessary. This system should alarm when a critical event on a particular server, device, interface, or communication path occurs. Although no single utility department is capable of responding to all the various alarms that might result from this system, the messages could be relayed to the appropriate group for troubleshooting and resolution.

4.2.3 Cyber Security Lessons Learned

Cyber Security Lessons Learned during the conduct of the SGDP include:

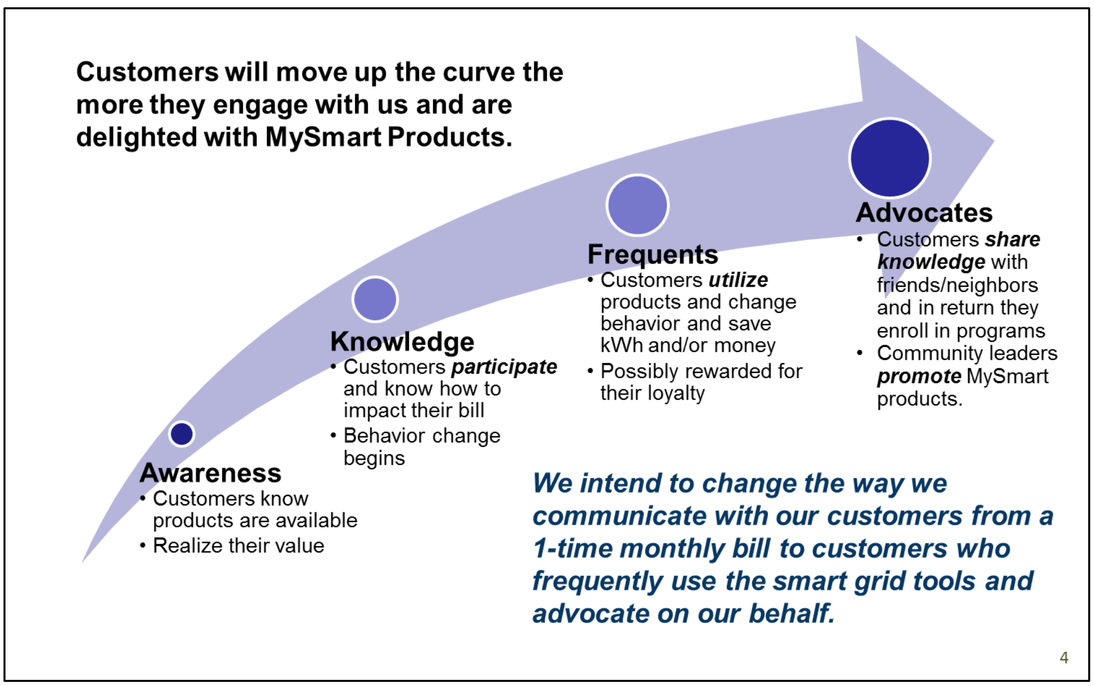
- The convergence and cooperation of IT and operations is paramount when deploying IP-based communications in the substation and beyond. If responsibility is shared between these groups, then management needs to clearly define roles and responsibilities and encourage open dialogue and cross-training. Alternatively, management could create a new, cross-functional support group that has the expertise to bridge the gap for installing, maintaining, and troubleshooting both the networking hardware as well as the end devices that utilize IP-based communications.
- Cyber security requirements should be incorporated into processes for vendor selection and for procurement. Internally hosted systems should consider access control, configuration management, system/communication protection, and system/information integrity. Systems hosted by a third party should also consider continuity of operations, incident response, media protection, and physical security assessments.
- Physical access control and key management should be done via a centralized, electronic platform. Such a platform allows for regular, inexpensive key refreshes; the capability to quickly modify user access permissions; and the capability to provide logging information to security.
- Cyber security zones and robust network segmentation should be established to comply with current and future industry standards pertaining to IP-based communications.
- Strict isolation should be implemented between distribution- and transmission-level assets in the substation, especially if both utilize IP-based communication. This isolation is also necessary for distribution- and transmission-level backhaul data. This isolation could be implemented logically via logical segmentation on shared network hardware, or physical via completely separate cabling and network hardware.
- Firmware, settings files, and Configured IED Description (CID) files for meter, field and substation devices should be maintained in a system for managing device configuration and versioning. Device firmware and settings should be verified on a routine, scheduled basis.

4.2.4 Education & Outreach Lessons Learned

Education & Outreach Lessons Learned during the conduct of the SGDP include:

- Based on the customer focus group, interest forms, and surveys, there is no silver bullet for customer communication channel preference.
- Reaching out to customers at existing community events was more effective than creating new, utility-sponsored events specifically for the SGDP effort.
- Consumers are looking for ways to manage energy, but don't know how to go about it. Most consumers weren't able to identify the energy hogs in their home, and they had a hard time translating the notion of efficiency into actionable steps; rather, they were seeking direction on the biggest bang for their buck.
- Utilizing a local labor force led to goodwill, but the Green Impact Zone ambassadors lacked product knowledge and their customer training skills were weak. Future programs should focus on sufficient training for the workforce.
- When deploying devices in customers' homes, capitalize on installer visits to offer a superior on-boarding experience and educate customers about general project initiatives and specific product offerings.
- Customer enrollment does not equal customer engagement. To remain engaged, customers need ongoing communication and education. As shown below in Figure 4-1, KCP&L created a customer experience timeline showing the ideal customer's progression over time.

Figure 4-1: The Customer Experience



4.2.5 SmartMetering Lessons Learned

SmartMetering Lessons Learned during the conduct of the SGDP include:

Advanced Metering Infrastructure

- Prior to the AMI rollout, KCP&L conducted a meter inventory/audit to identify safety, theft, and nonstandard situations. This preparation work made the AMI rollout more efficient and helped keep the AMI meters from getting blamed for other unrelated issues.
- KCP&L had a very successful deployment in terms of customer reaction and satisfaction due to strong and deliberate education efforts through numerous grassroots communication paths. KCP&L also met face-to-face with concerned and objecting AMI customers to discuss their concerns. This helped ensure a full deployment of AMI meters to all service points within the project area.
- Plans should be made for at least two AMI system software upgrades per year. These upgrades to the head end system and to the meters themselves are executed to provide additional functionality, performance, and scalability improvements, along with security enhancements. The upgrades need to be scheduled carefully to reduce impacts on AMI performance and system-to-system interfaces. All upgrades should first be thoroughly tested in a development environment.
- The daily performance of the AMI infrastructure significantly outperformed the legacy AMR system by establishing a consistent 99% daily read performance metric. With more than 30 days of reads and interval usage data stored on the meter and the gap-filling data retrieval functions of the AMI head-end, actual data capture was significantly improved, providing nearly 99.96% of meter interval data from functioning meters.
- KCP&L's AMI implementation has resulted in good outage and restoration message receipt rates. KCP&L's OMS received about 90% of outage/restoration messages via the AMI system, as compared to about 30% via the legacy AMR system.

Meter Data Management

- Loading historical AMI data into the MDM proved difficult. The MDM solution should be deployed at the beginning of an AMI rollout or its implementation planning should avoid the need for loading historical interval data.
- The MDM should be used as the system of record for all interval and register meter read data, as well as for all meter asset and configuration information. As the system of record for meter read data within a utility, the MDM needs to have robust capabilities to export meter read data to external systems through a variety of mechanisms, frequencies, and formats.
- The ability for a new MDM system to enable new rate types might be hampered by a utility's legacy customer information system or billing system. Many older systems aren't able to ingest billing determinants from the MDM. Utilities should understand the limitations of their legacy customer information and billing systems prior to MDM deployment.

4.2.6 SmartEnd-Use Lessons Learned

SmartEnd-Use Lessons Learned during the conduct of the SGDP include:

- Saving money on their bill was the primary reason that customers signed up for a SmartEnd-Use program. Customers expected a 23% average savings on their energy bill with the new tools. Secondary motivations were control over energy use and concern for the environment.

- Several SmartEnd-Use products allowed customers receive a daily estimate of their monthly bill. Many said that this was the program feature that gave them the most value.
- Wait to deploy customer thermostats, in-home displays, and HAN devices until after the customer's AMI meter has been installed and stabilized for a few weeks. Premature deployment of devices only frustrated customers, because unstable AMI meter communications prevented the devices from working properly.
- KCP&L's separate, dedicated support staff for SmartEnd-Use programs and tools was very beneficial — the traditional customer support staff fielded billing and lights-out calls, so they were not well-versed in the specific SGDP products.
- Two-thirds of customers in the SGDP service territory were renters. Because of this highly transient population, additional engagement was required, especially to transfer devices and program enrollment to new places of residence.
- Meter exchanges were problematic with the SmartEnd-Use devices. The devices maintained their associations with the old meter, and required manual provisioning to the new meter. An automatic provisioning process would alleviate this issue.

<u>Home Energy Management Portal</u>

- The HEMP functionality didn't evolve as originally envisioned throughout the duration of the project. A robust portal would have allowed customers to easily control DR participation, set their preferences for priced-based programs, and remotely control their devices.
- Customer usage of the portal waned over time. The HEMP should have ongoing, proactive marketing and be deployed in conjunction with other customer self-service functions to encourage ongoing portal usage.
- Close communication with the portal vendor is important to ensure that upgrade strategies and timelines align with the utility's goals. Portal upgrades should be used as an opportunity to engage with customers and promote use of the portal.

<u>In-Home Display</u>

- Based on customer surveys, the IHD was an underutilized device. Customers don't need a highly interactive device on a wall or counter; rather, they would prefer a single, mobile device (like their smartphone) with an application for home energy management.
- An IHD needs to be immediately useful upon installation in order for the customer to have any long-term engagement potential. The customers that received the IHD in parallel with their AMI meter were not able to do anything with the device for several days, until the AMI network communications stabilized. As a result, many of these customers failed to use the IHDs at all, even when the devices became functional.
- Customers that did use the IHDs really liked the estimated bill feature, especially because KCP&L considered the added taxes and fees in the number presented on the IHD.
- Of customers that used the IHD, 89% also took other energy-saving actions based on their IHD use. This shows that the IHDs heightened awareness of energy usage.
- IHD connectivity was only verified during IHD provisioning to the AMI meter. KCP&L could not "ping" IHDs to verify connectivity. The ability to remotely verify IHD connectivity could trigger communications to enhance engagement with customer's where an IHD is not functioning properly.

<u>Home Area Network</u>

- A successful HAN installation requires a carefully planned set of coordinated steps between the device installer and the customer service representatives performing the device provisioning to the SmartMeter. When the process was not followed properly, issues would arise with devices joining improperly or not joining the network at all.
- Customer broadband connectivity issues prevented many HAN thermostats from participation in DR events. If the utility DR program is going to rely on the customer broadband and Wi-Fi network, the utility needs to implement proactive HAN monitoring and initiate customer contact to restore HAN communications so that devices are available to participate in DR events.
- Utilities should manage the provisioning of the meter to a single HAN gateway. All other customer HAN devices should be provisioned by the customer to the HAN gateway. It doesn't make sense for all HAN devices to be provisioned through the AMI meter, as was required by the SGDP vendor's implementation of ZigBee SEP 1.x.
- Industry trends now appear to favor HAN devices that communicate over Wi-Fi rather than ZigBee networks. Since many customers already have a Wi-Fi network in their home, they don't have to maintain an additional network.

<u>Time-of-Use Rates</u>

- Overall, enrollment in the TOU program was higher than anticipated. TOU enrollment peaked in 2013, with approximately 1% of the SmartGrid Demonstration customers enrolled.
- Program design and communication are crucial to customer acceptance. Customers were receptive to an aggressive TOU pricing program (6x rate differential) if the program was simple to understand and the customer's risk exposure (On-Peak hours) was limited.
- KCP&L further reduced customer risk by allowing customers to exit the program at any time and, upon request, customers could be credited for increased costs incurred by the pilot TOU rate for the current and previous billing cycles only. While very few customers exited the program, customers viewed this as a positive aspect of the program.
- Overall, customers were satisfied with the TOU program, and on average participants reduced their On-Peak electricity usage by 15-20% and saved money, an average of $68, on their electricity bills.

4.2.7 SmartSubstation Lessons Learned

SmartSubstation Lessons Learned during the conduct of the SGDP include:

- Utilizing a phased deployment for the SmartSubstation components was imperative for project success. This approach gave each relevant work group time to get accustomed to the new technology and gain trust before adding additional layers of complexity.
- Selecting substation relays that could provide parallel communications to both the legacy EMS (via serial) and the new substation data concentrator (via IEC 61850) was key. The dual communications allowed the legacy transmission SCADA and new DMS to monitor all elements of the substation while allowing control to be effectively switched between systems as the SmartSubstation functions were deployed, tested, and operated.
- Many of the SmartSubstation components are more easily deployed when procured from a single vendor. When additional vendors are introduced, the complexity of integrating these technologies increases dramatically.

- The span of control between transmission operators and distribution dispatchers needs to be evaluated to fully utilize the SmartSubstation components. Currently, KCP&L's transmission operator is responsible for distribution bus voltage and operation of transformer load tap changers, plus the operation of substation bus tie breakers for internal substation load transfers. Distribution system operators currently only operate distribution feeder breakers inside the substation. Since the First Responder applications were designed to operate all of these devices, the distribution system operators need to have control of these distribution assets.
- The convergence of IT/OT staff within the SmartSubstation can be problematic unless careful planning and coordination is performed between the various work groups at the project initiation.

<u>Substation Protection Network</u>

- It is feasible to design, construct, and run a multivendor substation protection network, but there are certainly drawbacks to this approach. The hybrid approach yields uncertainty in regards to functionality and failover time. Testing out the proposed network architecture in a lab environment was critical prior to deployment of the networking equipment in the production environment.
- Utility department ownership of the substation protection network isn't clear cut. Some utilities give ownership to the Network Services team, while others add this to the responsibilities of the Substation or Relay System Protection teams. Meanwhile, other utilities are creating a third, hybrid group that specifically addresses this mix of skill sets. A clear ownership structure is essential to ensuring that the network is operational and maintained.

<u>Distribution Data Concentrator</u>

- If using report by exception rather than traditional SCADA polling, careful attention must be given when determining the analog deadbands to avoid excessive analog reporting from each device (and potentially overloading the data concentrator). Utilities should consider setting a deadband on only one type of analog in the 61850 report dataset. For example, they might set deadbands on all of the current values, so that only changes to the system current would trigger data transfer.
- As the points list is created, it is important to understand the logic and arithmetic capabilities of the data concentrator. Utilizing these functionalities could limit the number of data points brought back from each device, as the data concentrator could calculate certain values rather than sending everything from each device. For example, instead of bringing back all the points associated with voltage, current, and power, the device could just send the voltage and current data and the data concentrator could calculate the power values.
- CID file versioning and proper device configuration management is critical to managing a 61850 substation implementation. If the CID file on the device doesn't exactly match the CID file on the data concentrator, then the device becomes unreachable.

Human Machine Interface

- The HMI was useful for both the SGDP team as well as the system end user – the relay technicians. By using the HMI at Midtown Substation, the technicians were able to see the status of all substation devices in one place, rather than walking around to each relay to troubleshoot or test. While this is obviously a convenience to the technicians, it can also enhance the safety practices for all operations personnel.
- The HMI provided visibility to the status of the substation protection and control network, which was a major benefit to the project team. When a communications issue with a particular device was discovered via the data concentrator, the team could easily determine whether the root issue was related to the device itself or to network equipment.

GOOSE Messaging

- Deploying GOOSE schemes in a slow, incremental process was necessary for protection and control engineers and relay technicians to gain trust.
- Although the cross triggering GOOSE scheme didn't result in any actions taken by substation relays, it was very beneficial for KCP&L engineers. They were able to see the status of all substation devices any time an event occurred in the substation, and this was useful for post-event analysis.
- Understanding the impact of communications failures on the outcome of various substation events with and without the GOOSE schemes is beneficial. GOOSE schemes should be designed in such a manner that if communications fail and the devices operate based on their local protection settings, then the result is no worse than the pre-GOOSE scheme.

Substation DCADA

- By design, the substation DCADA (local substation automation controller) is supposed to operate in closed loop in the substation without any user intervention. The user has the authority to enable and disable DCADA closed loop at the substation, but the user does not have the flexibility to authorize individual decisions made by DCADA. This proved to be a major change-management issue as the operations group was uncomfortable in relinquishing complete control from the onset. Though incongruent with the DCADA philosophy, additional flexibility in terms of user intervention — at least during the implementation or testing phases — would help gain the trust of the operations group and transition into full-fledged closed loop mode.

4.2.8 SmartDistribution Lessons Learned

SmartDistribution Lessons Learned during the conduct of the SGDP include:

- Careful scheduling was required to accommodate all of the necessary field crews required for field device deployment. The recloser deployments, for example, typically took five different field crews: engineering, construction, distribution field operations, radio, and relay technicians. In order to deploy a field device network enterprisewide, a utility should look at its field crew responsibilities and consider modifying roles to make the process more efficient.

- The need for adequate change management for operational personnel cannot be overemphasized when deploying automation to the distribution system. In addition to addressing work practices dealing with individual device construction and operating practices, grid operations practices must also be addressed. Some specific examples of decisions for discussion include: Will Volt/VAR be allowed to run in closed loop? Can the system be allowed to switch itself, both to isolate and restore? Can the system be allowed to optimize away from its typical steady state?

Outage Management System

- The outage and restoration events delivered by the L+G AMI were much more reliable than what KCP&L has experienced with the traditional AMR “last gasp” outage alerts.
- When power was lost, the AMI meter waited approximately 30 seconds before broadcasting a power outage event. This eliminated “last gasp” alert broadcasts caused by momentary interruptions; the meters continued communicating for an additional 60 seconds to ensure that the event messages were transported through the mesh network. For this project, KCP&L found that the AMI Head End receives over 90% of power outage events, far superior to the 25% experienced with the legacy AMR system.
- When power was restored, the meter set an internal timer that was used to calculate the restore time once the network was re-established and network time was reset in the meter. The meter sent a first power restoration event message when network communications were re-established. A second power restoration event message was sent 5 minutes after network communications were restored as a precaution in case the network backhaul was not fully established when the first message was sent. The majority of power restoration messages were typically received by the AMI Head End within 5 minutes of the actual power restoration, and 95% of the power restoration events were typically received within 15 minutes.

Distribution SCADA

- Current distribution SCADA technologies do not provide all of the capabilities that will be required to support the future requirements of the smart grid.
- Maintaining the distribution SCADA database is very labor intensive and prone to error. For each field device deployed, great attention and user involvement was required with loading/verification at every step of the communication path. Care was needed to ensure proper naming conventions and appropriate cross mapping between DNP and 61850 naming. These efforts to enable substation and field device communications were a notable contrast to the deployment of incremental AMI meters in the field. In the same way that meters would self-identify and propagate communication point capabilities, other distribution devices would benefit from these same capabilities through to all systems with which they communicate.
- Since data from the field devices is sent upstream periodically or reported by exception, all systems using this data need to receive, display to the operator, and act on the data quality (good, bad, telemetered, non-telemetered, entered, etc.) and the time stamp (staleness) of the data.
- When it comes to field devices, the industry is far from achieving device interchangeability. Interpretations of industry standards vary greatly from vendor to vendor. The majority of field devices on the market today are still based on serial communications.

Distribution Management System

- Deploying a complex system like a DMS should be done in phases. KCP&L successfully separated the deployment into the following phases where possible: substation device point-to-point checkout, field device point-to-point checkout, First Responder open loop testing, and finally, First Responder closed loop testing.
- A detailed network model is critical for the success of an intelligent distribution system. All of the proper network elements and their connectivity are necessary for state estimation. Additionally, precision is required for accurate load flows (power flow) and stability-type analysis.
- Any time a new device was added to the GIS, it required the redeployment of the entire network model throughout the various distribution systems. This resulted in significant system downtime to update and re-stabilize the system. An incremental network model migration capability from the GIS to the DMS and other systems requiring network topology is critical for future enterprise deployments.
- For most Distribution Management Systems there are several modes of control, such as complete user control, open loop control, and closed loop control. With an anticipated future in which multiple systems would integrate together forming a single DMS, there is a need for a single hierarchical control system that interacts with all systems yet still gives complete authority to the operator at needed times.
- Having a lab environment for testing the First Responder applications was not very beneficial, because the First Responder applications require a significant quantity of frequently updated data from devices in the field. In a production environment, legitimate devices continually provide this data. However, in the lab environment, it is challenging to simulate or compile enough data to truly simulate an entire distribution footprint.

ADA Field Area Network

- A mesh network for Advanced Distribution Automation functions best when its size allows for multiple paths to any node. Unfortunately, KCP&L's mesh network was too small (in geographic span) to realize the benefits of multiple paths. Thus, when one node went down, multiple backup paths were not always available.
- In order for the mesh network to perform as well as possible, it is critical to have as many takeout points as possible. This would decrease the hop count and decrease the burden on any single set of gateways.
- The use of wireless network technology for ADA means that the data concentrator needs to support less-than-ideal communication quality. Although many data concentrators claim to handle wireless communications, most on the market today were built to work with wired communications.

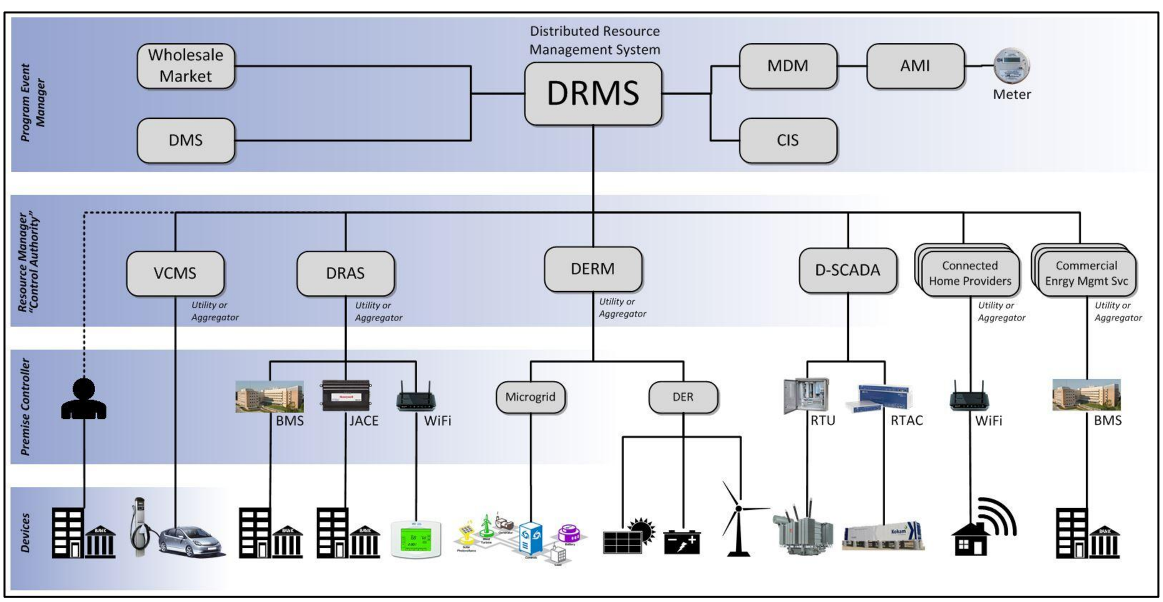
4.2.9 SmartGeneration Lessons Learned

SmartGeneration Lessons Learned during the conduct of the SGDP include:

<u>Distributed Energy Resource Management System</u>

- Current standards are not sufficient for DMS/DERM interactions. For the SGDP, the vendors created a custom DMS/DERM interface. They utilized IEC 61968 for dynamic message exchanges, but they had to create numerous extensions to the standard to pass the necessary information between systems. A significant amount of industry work needs to happen in this standard for it to be sufficient for the exchange of power flow and state estimation messages.
- To perform geographic load reduction, the DERM required a network topology model. Since the DERM isn't typically the system of record for this model, careful consideration must be given for how to keep network topology models synchronized across back office systems.
- Originally, KCP&L thought that direct load control DR events needed to be done with utility infrastructure. Because of the development of the OpenADR messaging standards with availability assessment and post-event analysis messaging, however, this might not be as critical going forward. If utilized properly, OpenADR messages could notify the event scheduler (utility) if assets are offline or already being utilized.
- Unlike many other back office utility systems, the DERM system isn't fully defined yet; rather, it's an evolving technology, and its functions still need to be defined and vetted across the industry. Various vendors have approached their product offerings with different strategies, yielding various "classes" of systems (DRAS, DERM, etc.), with each managing a specific type of distributed resource asset. Through this project, KCP&L defined the DERM as a higher level critical component for optimal scheduling (both geographical and economical) of demand response and distributed energy resources. KCP&L's hierarchical architecture for the distributed resources management moving forward is as shown below in Figure 4-2. In this diagram, the DRMS represents the SGDP component referred to as the DERM.

Figure 4-2: DRMS Proposed Architecture



Battery Energy Storage System

- The BESS is a complicated system with very complex internal control systems. It is not a set-and-forget system like most other distribution technologies. Rather, it requires a significant amount of ongoing operational monitoring and support.
- While it may be possible for a utility to achieve economic benefits from Energy Time Shift, Peak Shaving, and T&D efficiencies, the most significant components in determining the economic viability of a BESS for a utility are still the upfront installed cost of the unit and the ability to derive additional benefit streams from wholesale ancillary service markets.
- The annual average daily round trip efficiency of the BESS was determined to be 75%, but it varied significantly with the daily average temperature. To improve operational performance of future BESS specifications should focus on improving the efficiency of auxiliary loads and installing improved insulation and more efficient HVAC units on the SMS and battery enclosures.
- Manufacturer's recommended discharge thresholds need to be followed to protect the battery and maintain its life. These thresholds and the efficiency of the inverter need to be factored in when sizing the battery storage component. For example, KCP&L's 1.0-MWh battery could only deliver a net impact of 780 kWh to the grid.
- For BESS resources operated for Electric Supply Capacity and T&D Upgrade Deferral functions, KCP&L's analysis shows the optimal economic configuration of BESS assets is to install between 4.0 MWh and 5.0 MWh of storage capacity for each MW of inverter capacity.

Premise Energy Storage System

- A PESS is a good potential business opportunity for the utility to collaborate with customers. It provides an edge-of-grid platform for improved customer resilience, allows the customer's PV to continue generation during outages, provides the customer additional savings potential with TOU rates, and provides a resource for the utility to call upon for DR.
- The PESS avoids the major neighborhood storage issue: Who gets to use the power when islanding occurs? If the storage is done at the premise, then the individual customer completely controls what the storage is used for and how long the storage lasts.
- The SGDP PESS ratings, 6.0 kW/11.7 kWh, appear appropriately sized to serve the critical loads of most residential homes in the KCP&L service area. Combining the PESS with a 4.2 kW or larger solar array would allow the critical load panel (CLP) loads to be sustained through multiday restorations for the majority of the year.
- The customer's home Wi-Fi network and Internet connection remain operational during power outages. Without the Internet connection, the customer's ability to monitor and manage the PESS is lost. It may be necessary for the customer to have a backup cellular internet connection for the PESS if the customer's normal home Internet supplier loses service due to widespread power outages.
- It is important for the customer to understand the energy consumption characteristics of the loads connected to the CLP. Approximately half of the daily energy consumption may be attributed to the furnace fan. To further extend the PESS's capabilities, the customer should consider implementing additional energy management controls for loads connected to the CLP.

Solar PV Generation

- Any agreements for siting utility-owned solar generation on a customer's property should be structured in a manner that does not create unmanageable property encumbrances for current and future owners.
- KCP&L determined that NREL's New PVWatts Calculator, released in the fall of 2014, provides very credible estimates for sites in and around Kansas City. It estimates that a rooftop solar installation in Kansas City would produce 1,389 W-AC per kW-DC annually for an annual solar production load factor of 15.85%.
- KCP&L's analysis determined that that the coincidence of solar generation with the utility's system peak could range from 40% to 55%, depending on when in July or August the peak condition occurs. If a system peak event occurs in early July, solar coincidence as high as 55% may be expected. But as peak events occur later in the year, the coincidence reduces — to 40% by late August.

Vehicle Charge Management System

- The charging station program deployed for this project was developed within current legislative and commission constraints: 1) No tariff exists for KCP&L to sell (or give away) electricity at public charging stations, and 2) Missouri and Kansas do not allow resale of electricity by third parties. As a result, businesses were recruited to host the charging station, meaning that the business would provide the parking space and pay for the electrical consumption. The EV charging was provided at no cost to the EV owner. This model is not desirable long-term, so new legislation and/or tariffs will be key in the development of public EV charging programs.
- Site selection is key to the early utilization of the public charging stations. The best sites are highly visible locations where current and potential PEV owners work or frequent. Overall charging station usage increased throughout the duration of the project as current and prospective PV owners became aware of their existence and the adoption of electric vehicles increased.
- Location is also a critical factor in determining EVCS utilization. Locations that generate multiple, moderate duration (1-2 hours) visits can have multiple charging sessions daily, providing the best overall EVCS utilization. Employee parking locations, while used daily, tend to only generate 1 or 2 charge sessions per day.
- Monitoring of all EVCS locations generated the following generalizations regarding usage of charging stations.
  - annual electricity consumed by PEVs is 28.586 MWh
  - average connect time is 4.5 hours
  - average charge duration is 2 hours, 20 minutes
  - average charge is approximately 7 kWh
  - most common charge rate is 3 kWh/hour
  - less common charge rate is 5.5 kWh/hour

4.3 Technology Gaps

This section describes the Technology Gaps identified for all demonstrated technologies. These gaps outline some of the areas where the industry needs to advance. Other utilities may find benefit in understanding where they could run into issues in similar implementations. Vendors could benefit by addressing some of these issues and advancing the available technologies on the market. Technology Gaps are provided for SmartMetering, SmartEnd-Use, SmartDistribution, SmartGeneration, and Interoperability. More detailed explanations of these Technology Gaps are included in Section 2 and Section 3. The most significant highlights are listed below.

4.3.1 SmartMetering Technology Gaps

The SmartMetering technologies used in the SGDP proved to be relatively mature technologies. Very few industrywide technology gaps were identified.

Advanced Metering Infrastructure

- AMI systems need to automatically re-establish the ZigBee HAN connections when meters are changed out. The manual reprovisioning process currently used will become too cumbersome and labor intensive as users and utility programs rely more heavily on data and messages received from the meter.

Meter Data Management

- The functionality of MDM systems needs to be expanded, or developed in a companion system, to manage all characteristics of the meter. The MDM needs to provide centralized configuration management and firmware version tracking across all meter platforms.
- The MDM system is expected to be the system of record for meter read data and, therefore, needs to have robust capabilities to export meter read data to other back office systems that have traditionally received such data either from the CIS or directly from the meter reading systems. The MDM system should be capable of:
  - Exporting the meter read data in multiple formats: Green Button, IEC 61968-9, CSV, and others.
  - Pushing meter data on a predetermined schedule, and responding to real-time requests for data based on a list of customers and a time period.
- Other back office systems should have the ability to consume raw, uncorrected meter data, VEE'd data, and subsequent corrected versions of data provided by the MDM.

4.3.2 SmartEnd-Use Technology Gaps

Although KCP&L encountered a number of issues in the SmartEnd-Use project component, the industry is already working to resolve many of these. This part of the grid has seen a multitude of newcomers over the past decade, and each of these entrants is bringing new ideas and devices to leverage and build upon the foundation laid by early pioneers in the home energy automation space.

Home Energy Management Portal

HEMP technology hasn't advanced as quickly as anticipated. Most portals today are limited to display of customers' energy usage information along with energy efficiency tips and programs, with limited end-use device management and control.

- In the future, HEMPs should support:
  - Opportunities for customers to manage their usage from a pricing perspective, so that price-based demand response programs are feasible
  - Distributed resources
  - Solar
  - Smart appliances
- As HEMPs evolve there will likely be a separation between customer and utility portals.
  - Utility customer portals will likely be focused on energy presentment, energy efficiency alternatives, energy products, and pricing options.
  - Customer home energy management systems will likely focus on the "connected home." Such systems would register devices, provide security and home automation, integrate with the utility to receive pricing signals, and manage solar, PEV, and smart appliances.

Home Area Network

KCP&L utilized the ZigBee SEP 1.x for the project. It didn't have all the functionality needed for KCP&L's project, so both the ZigBee SEP and the Home Automation profiles were utilized in order to get as much of the desired functionality as possible. In addition to the lacking functionality, all HAN devices were required to register to the meter. This approach would be impractical moving forward, as it would force the utility to provision all the smart devices and appliances in the customer's home.

- Many of the technical issues with ZigBee and SEP 1.x are being addressed by current efforts via SEP 2.0 and other home automation protocols, but here are some of the necessary requirements moving forward:
  - Need ability to differentiate between different types of load control switches for demand-response events.
  - Air conditioning cycling with fan control is needed as a thermostat DR event mechanism.
- HAN implementations should evolve such that devices are provisioned to a customer gateway, allowing the customer to install any end-use devices desired within the home. With this design, the utility would be responsible only for provisioning the gateway and any utility managed direct load control devices to the meter.
- The customer home energy/automation space needs to continue to evolve and provide capabilities required for increased customer participation. Most likely this will be better handled in the near term by "connected home" providers, rather than the traditional electric distribution utility.

4.3.3 SmartDistribution Technology Gaps

Throughout KCP&L's SGDP, it became clear that the SmartDistribution project component was the area with the most technology gaps. Currently there are many changes occurring within the distribution grid, and vendors are scrambling to get products to market. Vendors rarely consider the scalability of their solutions, and rarely do their designs accommodate multivendor solutions. The following items describe some of the major technology gaps that KCP&L discovered in SmartDistribution.

Device Control Functionalities

To add intelligence and automation to the distribution grid, many IEDs will need to be added to the distribution lines. Vendors should do a better job of preparing their controllers for the proliferation of these devices. The current industry approach for controllers outside the substation walls is similar to the approach for controllers attached to substation devices: Each vendor utilizes proprietary software for developing configurations, and many controllers are accessible only via local interrogation. This approach won't be sufficient for field devices, due to the sheer quantity of devices and the geographic reach of their deployment.

- In the future, IEDs need to do the following:
  - Support a predefined mode of operation in the event of communications loss from the data concentrator.
  - Be capable of simultaneous reporting of multiple points from a single deadband instead of multiple unsynchronized deadbands.
  - Provide native IP support instead of relying on communications radios to translate from serial to IP.
- Third-party software developers need to create a common software package that utilities could use to develop configuration and settings files applicable to all device manufacturers.

Application Profiles

Even when vendors develop products using specific industry standards, there is ample room for interpretation and manufacturer-specific implementation. This is problematic when utilities are trying to achieve interoperability and multivendor interchangeability.

- Device application profiles should be created, defining the following:
  - A common set of analog, digital, and control points for a particular type of device.
  - A common set of device behaviors, with prescribed methods for performing those behaviors.
- Devices should be certified to an application profile via an external agency instead of utilizing self-certification.

Remote Device Configuration and Management

In contrast to legacy devices, current IEDs require frequent changes to firmware, settings files, and other configurations. Although local updates to devices may be feasible with substation devices, this approach is not scalable for field devices across a utility's entire service territory.

- IEDs need to support the following:
  - Remote monitoring of firmware, settings files, and configurations.
  - Remote updates of firmware, settings files, and configurations via over-the-air pushes.
  - Remote detection of changes made in the field.
  - Remote password management and versioning control.
  - Automatic configuration with the SCADA server when connected to the network.

SCADA Systems

As the volume of smart devices proliferates, discrete polling of devices will become impractical. Radio frequency communications have introduced challenges for many legacy RTUs and communications controllers, and legacy SCADA provides operators with nominal real-time data. Legacy SCADA technologies must adapt to new communications technologies and paradigms to support the emerging smart grid with high volumes of low-cost sensors and controls.

- In the future, SCADA systems and RTUs should:
  - Accommodate high volumes of devices reporting by exception rather than utilizing traditional polling methods.
  - Accommodate "sleepy" sensors that "wake up" to report.
  - Present operators data with increased degrees of variability, to accommodate intermittent renewable generation.
- SCADA communications need to adapt to handle significantly more points per device than in the past, to facilitate new smart grid applications.

SCADA Control Authority Management

Current distribution SCADA systems have an all-or-nothing approach to control authority. Future distribution systems will require control to be established at various network levels (substation/transformer/bus/line/device), in multiple modes (centralized/decentralized), and by multivendor systems controlling different grid components.

- Control management messaging between systems should be developed as a standard protocol so that the control authority management can be extracted and placed into a separate system, controlled independently. This would allow for authority communications between systems from divergent vendors.
- SCADA systems need to utilize an independent control authority manager, which should do the following:
  - Allow an application to have control authority only over the subset of devices that it requires for operation, doing whatever optimization is possible with the devices that it has been given designated control authority.
  - Define the appropriate designation of control between different systems that can control the same assets.
  - Define the appropriate designation of control priority and data management in the case of two separate localized areas (substations) that share common assets.
  - Control competing priorities between different applications. For example, they need to be able to operate different applications in closed-loop versus open-loop modes.
  - Operate different applications locally and centrally in open-loop or closed-loop modes. For example, the operator might want FISR to be run locally in closed-loop mode, but VVC to be run centrally in open-loop mode.
  - Facilitate the concept of "control reservation," where control authority would be granted for a specified length of time and then released automatically, relinquished to default or previous device mastership.
- An operator should be able to intercede and make a tactical choice to implement a change without having to go through the full process of taking back control.
- SCADA data can't all be handled at the control center moving forward. The DMS solution of the future needs to have multiple levels of control hierarchy, to accommodate the increasingly large amounts of information on the distribution system.

SCADA Model Management

Legacy SCADA models are typically manually constructed and, thus, very labor intensive. In the future, they must adopt new technologies for constructing, managing, and maintaining their data models.

- Vendors should work toward GIS-supplied device configurations, since most utilities use GIS as an asset repository.
- Devices should have configuration templates to define standard point mapping. This would help to streamline the process for adding new devices.
- Industry standards (ICCP, IEC 61850, and DNP) must adopt compatible naming conventions for SCADA points to minimize point name transformations between systems.
- Devices should be plug-and-play and have the ability to automatically configure themselves with the SCADA server when connected to the network.

Advanced Distribution Management Systems

Distribution Management Systems available today vary greatly in terms of capabilities and base functionalities. Some DMSs are simply distribution SCADA systems with OMS capabilities. Others have various applications to locate and isolate faults and to reconfigure circuits. Such systems claiming to be “advanced” should have some similar functionalities, as described below.

- Many DMS vendors today claim that their systems have advanced applications, when in reality they are far from advanced. DMS applications have a lot of growth potential. Some key improvements that are needed for future DMS applications include:
  - Analysis areas must be highly configurable and granular. They should be broken down by system, area, substation, transformer, bus, feeder, and device.
  - Additional flexibility for application parameters is needed to allow different settings or algorithms for different areas of analysis.
  - DMS applications must be able to run in different modes for different areas of analysis. For example, a user might want to run applications in a closed loop for the majority of the system but, for a subset, the closed-loop mode might need to be deactivated due to planned work to be carried out in that area. An option to select closed-loop versus open-loop operation then would be needed, based on injection point or even down to the circuit level.
  - The load-flow solution has been a required element of many DMS applications, but is often difficult to achieve due to the data quality of distribution models. As more sensors proliferate in the distribution network, it may be possible to base most DMS applications on the results of state estimation. A good state estimation will go a long way — it just won’t disclose system losses.
- Current DMS models are bulky and difficult to update. Instead of approaching distribution modeling as they have approached transmission modeling, vendors need to take a completely different approach to make the form meet desired functionality.
  - Where possible, a single, standards-based network model for the distribution system should be utilized.
  - Network model updates should be driven by the frequency and volume of real-time changes to the distribution network. Model updates should be streamlined so as not to require human intervention unless data discrepancies arise.

- The granularity of the modeling system of record, typically the GIS for the distribution network, needs to be carefully considered for ingestion by the DMS. Often the GIS models pole-to-pole spans, which are too granular for many load flow/state estimation algorithms currently available.
- Lightly loaded areas of the distribution network do not have a high level of interconnectivity, so they could be optimized and analyzed based on a simplified model. Network applications should be simplified to use a heuristic or logic-based approach rather than a running power flow solution.
- Heavily loaded areas of the distribution network that are highly interconnected should use a model-based approach. These areas require advanced algorithms to make recommendations based on the real-time state of the network and optionally carry out the remedial actions to alleviate power flow violations or isolate and restore power to as many customers as possible.

• The DMS needs to adapt to accommodate distributed generation and other edge-of-grid device requirements. Currently, distributed energy resources are often modeled as negative loads, but this isn't sufficient or accurate. To accommodate the growth of distributed generation in the future, the following changes should occur with the DMS:
  - The DMS must model distributed generation appropriately and include these assets in the advanced DMS applications.
  - The advanced DMS applications should have the ability to control distributed generation.
  - The DMS needs the capability to request geographically constrained load reduction from the Distributed Resources Management System and analyze available DR/DER potential.

• As the DMS grows to incorporate more SCADA data and functionality, it will be critical to consider data presentment and how the growing quantities of data are prioritized for the appropriate users. Without careful consideration, the DMS could contain an overwhelming amount of information, and the user wouldn't be able to focus on the relevant content.
  - The DMS user interface needs to be selective at various levels so as to only present truly important information to each system in the hierarchical level. This will prevent operators from drowning in lots of irrelevant data.
  - The various components of the user environment need to be reachable from within the same environment. They don't all have to share the same user interface, but the user should be able to seamlessly navigate from one to the next.

4.3.4 SmartGeneration Technology Gaps

This is rapidly emerging area, so it is difficult to identify technology gaps. As vendors work quickly to move new products to market, such rapid development is bound to lead to oversights and subpar integrations.

Distributed Resource Management System

Most of the industry currently utilizes separate systems for managing demand response and distributed energy resource assets. The industry commonly refers to these as Demand Response Automation Servers (DRAS) and Distributed Energy Resource Management (DERM) systems. To maximize effectiveness, there should be one higher-level umbrella system capable of considering and dispatching both DR and DER. The DERM system KCP&L implemented as part of the SGDP combined these functionalities, but this certainly isn't common across the industry. As noted in the previous Lessons Learned section, the concept of a DRMS was introduced to distinguish the function of the SGDP's DERM component from the more common DERM system functionality that has evolved over the duration of the project.

- Future Distributed Resource Management Systems (DRMS) should be capable of the following:
  - Knowing all demand response assets and their capabilities.
  - Knowing all distributed energy resources and their capabilities.
  - Receiving requests for load reduction from other systems, like DMS.
  - Selecting the best resources to utilize to minimize cost.
  - Selecting the best resources to utilize to solve a geographic problem.
  - Dispatching demand response event commands.
  - Dispatching commands to distributed energy resources.
  - Receiving availability information from the assets to keep real-time expectations aligned.
- The IEC 61968 standard for dynamic exchanges do not contain sufficient messages to pass the necessary information between the DMS and the DRMS, so extensions are currently required. A significant amount of industry work needs to happen in this standard for it to be sufficient for the exchange of power flow and state estimation messages. EPRI is currently working on a set of messages that would assist with some of the new back office administration — registration of assets in the DRMS, for example.

Battery Energy Storage Systems

- Regardless of the type of battery technology used, one common shortfall is that a function-specific controller is required to send the required inverter control signals to the BESS. In the future, vendors should create standard controllers that are capable of supporting a number of BESS functions.

4.3.5 Interoperability Technology Gaps

KCP&L encountered numerous project challenges in establishing the desired level of systems integration and interoperability with the current technologies. Many of the technology gaps impacting integration and interoperability have been outlined above. Several additional points are outlined below.

Standards Development Efforts

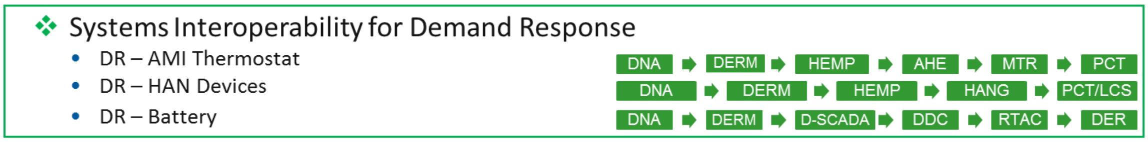
As KCP&L discovered throughout the SGDP, industry interoperability efforts have focused on standardization of the utility data model through CIM, back office systems communications via IEC 61968 and MultiSpeak, and communications to field devices via IEC 61850 and DNP. While these efforts have been important, they are not sufficient to achieve multivendor smart grid implementations.

- The CIM standard defines an informational model and not an implementation model. To achieve interchangeable, multivendor interoperability, the industry needs to focus on the development of application profiles. The application profiles would provide further functional definition, requirements, and constraints to the underlying standards. Each profile would be a collection of classes, attributes, references and behaviors, along with additional constraints that would be made by making attributes mandatory or restricting the cardinalities on associations. To enable a true plug-and-play multivendor smart grid, application profiles should have implementations configurations in:
  - IEC 61968 and MultiSpeak for back office systems integration.
  - IEC 61850 and DNP for communications to and between field devices.
- Naming conventions and point mapping need to advance to accommodate the transmission of data between systems and vendors. KCP&L utilized ICCP messaging for transmitting control and monitoring data between the user interface and the D-SCADA system, but IEC 61850 was used to transmit control and monitoring data to substation and field devices from the D-SCADA. These protocols had different naming conventions and the data points from the same device had to be assigned different names when moving from one system to another, which made data migrations and points list modifications complex.
- To promote IEC 61850 device interoperability between vendors, industry should develop standardized ANSI ICD and CID files on an application profile basis. This would provide utility engineers with a good starting point for developing their own specific standards. For example, all capacitor bank vendors could be plugged into any manufacturer's data concentrator and work interchangeably using one standardized ANSI capacitor bank CID file. Alternatively, all capacitor banks could be installed with a standardized CID file and the data concentrator would recognize it as a certain manufacturer's profile with a known behavior.

System Situational Awareness

With increased system-to-system integration, intermittent process and communication failures can have greater impacts to operations and raise the importance of proactive monitoring of systems and communication networks. A single process flow might travel through six or more different systems with stops at the ESB along the way. Figure 4-3 below shows several examples - three DR flows from KCP&L's SGDP.

Figure 4-3: Message Flows for Demand Response



- A solution is needed to provide a bird's-eye view of all of process components and their communications linkages that make up an integrated smart grid solution. This process dashboard approach should be tailored with content suitable for IT support staff, operations support staff, and grid operators. This process dashboard should accommodate the following:
  - An IT Network Operations Center to actively monitor the state of all system and intersystem processes and communications.
  - Relevant information flow to operations personnel.
  - Systems messaging for alerts, status, and exception handling.
  - Insight to communications failures several systems away.
  - Self-awareness of data quality to assist with the transition to more automated grid operations.

4.4 COMMERCIALIZATION

Although not a primary objective of KCP&L's SGDP, commercialization of smart grid technologies and products was certainly a secondary goal. For some project partners, this project experience reinforced existing assumptions about smart grid design and implementation. For others, this project modified their product road map, or even changed their over-arching smart grid strategy.

This section addresses the insights gained by project partners. The specific examples below are illustrative of the types of commercialization benefits that KCP&L's partners gained through this project. These examples are not all-inclusive, but do represent some of the most insightful feedback that KCP&L received from the project partners.

4.4.1 Technology Partners

<u>SmartMetering</u>

The commercialization aspects of SmartMetering focused on the AMI and MDM systems. While L+G's AMI solution was fairly well established at the time of deployment, there were some significant new challenges associated with KCP&L's project. Most of the commercialization benefit for L+G consisted of troubleshooting and bug-fixing efforts associated with ZigBee SEP 1.x. Together with KCP&L, L+G conducted extensive device interoperability testing between L+G and other vendors' devices. These efforts strengthened implementations for all devices that were using ZigBee SEP 1.x, a developing technology standard. According to L+G, "The result was a more seamless and valuable experience for customers who selected devices from two or more vendors."

In addition to assisting with the ZigBee SEP 1.x implementation, L+G's integration with Tendril on the Home Area Network helped to clarify L+G's understanding of the limitations of the first generation HAN application standard. This experience led to the proposal of additional functionality for standard adoption that was incorporated into subsequent generations of the SEP application standard.

Since L+G manages KCP&L's AMI network, this project provided L+G with experience in technology deployment that could be helpful for future enterprisewide deployment. This wasn't necessarily product commercialization, but rather service commercialization. The project helped L+G to improve functionalities and tools required to support various device installation scenarios (i.e., IHDs and thermostats) and support troubleshooting with limited customer interaction.

This project gave eMeter/Siemens the opportunity to demonstrate implementation of a hosted MDM that enables the complete meter-to-cash functions using an off-premise service. The project solution demonstrated a successful proof-of-concept in the hosted MDM market space.

Lastly, this project produced experience in IEC 61968 implementation. At the onset of the project, vendors were hesitant to utilize this standard for metering data, but KCP&L pushed them to implement it where possible. Through team work and cooperation, KCP&L, eMeter/Siemens and L+G advanced the standard to a new level of detail and operational capability. This feat enabled Siemens to differentiate between other MDM vendors that have not achieved such a high level of interoperational capability.

<u>SmartEnd-Use</u>

In the SmartEnd-Use project component, much commercialization was achieved through the deployment of the residential products. Many of these in-home products are very new, so experiences from each project deployment are critical for the product road maps and feature sets. KCP&L's SGDP helped L+G and Tendril identify shortcomings in the integration standards and push industry working groups to make necessary modifications. According to L+G, "While the road to commercialization of the standards-based Home Area Network is still a journey in the making, the KCP&L demonstration mobilized a key set of technologies and enabled vendors to drive this evolution toward a standards-based, interoperable, and consumer-engaging energy management solution."

In addition, Tendril's work with KCP&L led to growth of the vendor's own product. Tendril understood that customer engagement was important prior to the project, but its experiences on this project solidified the vendor's belief that segmentation is critical to improving engagement. According to Tendril, "Quite simply, each individual is unique and has different needs. Those in low-income environments interact with energy differently and require different types of messaging and incentives. With this learning in mind, coupled with experiences from working with other utilities, Tendril continually enhances its segmentation and micro-targeting functionality. These capabilities enable the delivery of targeted messaging that improves a customer's propensity to act."

SmartDistribution

The SmartDistribution component of KCP&L's project pushed some high-level distribution system philosophies. When KCP&L first drafted the proposal for this project, most vendors were adamant about centralized control of the distribution system. Very few believed that hierarchical control was a feasible strategy; Siemens was one of the few vendors that had the capabilities and the desire to pursue this approach. Although the legacy Siemens DMS that was deployed had a number of shortcomings, Siemens leveraged the learning from this project to drive its new DMS platform.

In addition to commercialization improvements to the DMS, the project also resulted in several improvements to the Tropos (ABB) mesh network, which was utilized for distribution automation. As a result of feedback from KCP&L, Tropos is planning several enhancements to its graphical user interface to allow for easy customization based on each utility's needs. Additionally, Tropos plans to provide functionality that will support encrypted communication to serial based device controllers. This wasn't feasible during KCP&L's project but, based on KCP&L's requests, Tropos prioritized this capability in its product road map.

SmartGeneration

In this rapidly changing area of KCP&L's SGDP, vendors were able to immediately apply project experience to their product road maps. The battery vendor, Exergonix, only had two Lithium Ion storage systems deployed worldwide at the beginning of the project, so the company certainly wanted to learn as much as possible from KCP&L's project. Exergonix used KCP&L's operational testing to help develop its product objectives moving forward. According to Exergonix, "What we learned about the future of energy through the SGDP was a more efficient way to deliver electricity with a high reliability level. As we look to improve performance and life of the overall system, our Next Generation distributed energy storage system will have the flexibility to integrate a higher energy density battery and will enhance reliability through advanced electronic controls, improving efficiency of the system and humanizing the life expectancy of a grid-tied unit." As a result of the SGDP, in 2015 Exergonix will be unveiling an advanced, turnkey solution that can help stabilize the grid of the future.

Another aspect of the SmartGeneration component that received commercialization throughout the project was the Distributed Energy Resources Management system provided by OATI. In order to fulfill the interoperability requirements of the project, OATI created several new interfaces: an OpenADR interface to communicate demand response events to the residential devices and the battery; an OpenCharge interface to communicate demand response events to the charging stations; and IEC 61968 messaging to exchange information with the DMS. In addition to the new interfaces, participation in KCP&L's SGDP reinforced OATI's stance on the role of webDistribute, one of its products. The product provides the functionality to manage individual DR and DER assets — both customer-side and utility-connected — to address various system, economic, and grid-reliability objectives while analyzing their impacts on the distribution grid and connected equipment. Other vendors have split up this architecture and required separate systems for DR and DER. This project confirmed that a higher-level system is needed that can call upon both types of assets.

4.4.2 Implementation Partners

In addition to the technology commercialization benefits, KCP&L's project partners also gained implementation experience. Several consulting firms assisted with the design, deployment, and operational testing for the project. All bolstered their services résumés with this comprehensive project. According to Burns & McDonnell, "Involvement with this project provided Burns & McDonnell engineers and consultants with broad, end-to-end utility systems implementation experience. Both the unique architectural design and strict interoperability standards approach have resulted in additional and valuable base experience as Burns & McDonnell assists other utilities with front-end smart grid and advanced technology feasibility studies and analyses." The Structure Group described how the project advanced its domain knowledge of a variety of smart grid technologies, in addition to improving its project delivery methods. The Structure Group was able to gain experience in vendor selection, requirements definition, system integration, testing, standards adoption, data analytics, and training/change management.

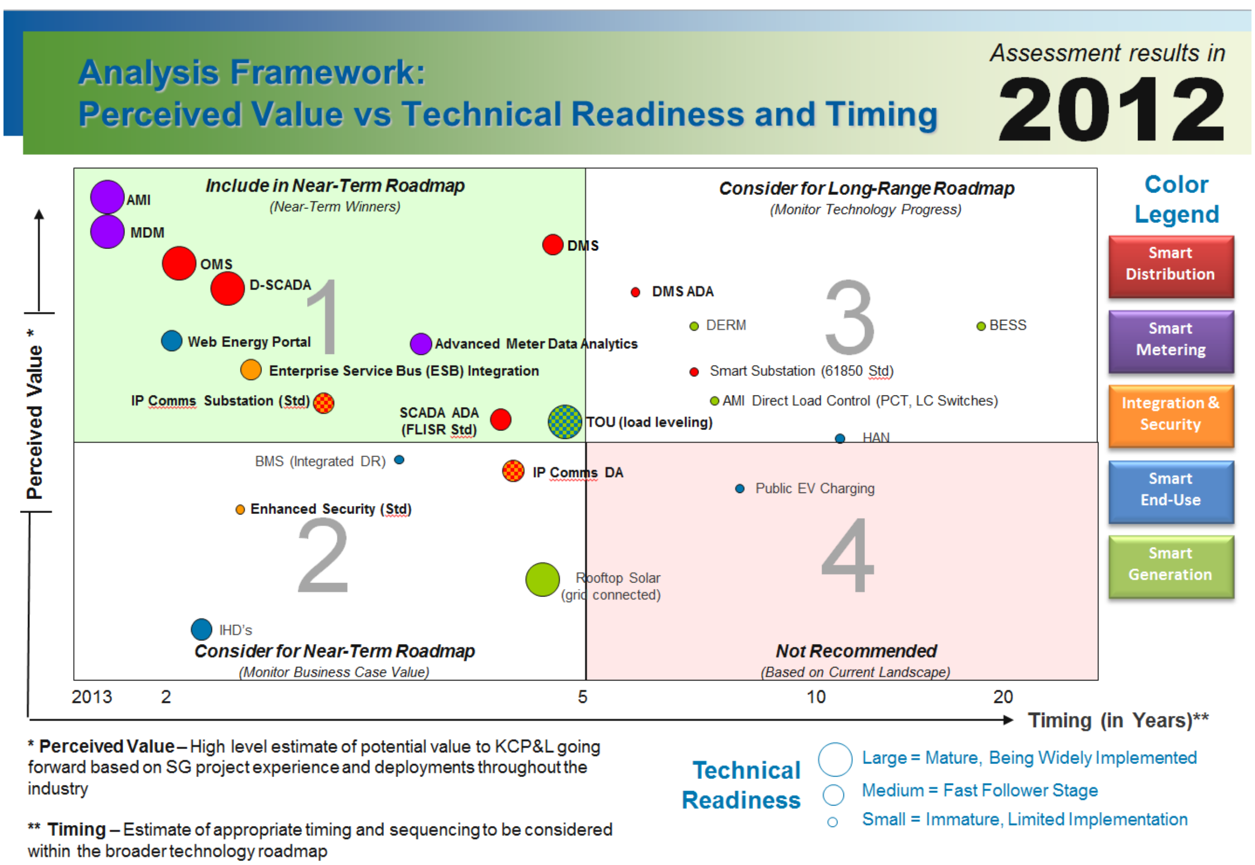
4.5 Project Impact on KCP&L's Future Plans for Smart Grid Deployment

The KCP&L SGDP successfully implemented and demonstrated an end-to-end smart grid that included renewable generation, premise and grid energy storage resources, leading edge substation and distribution automation and controls, energy management interfaces, and innovative customer programs and rate structures. These products were selected in 2009 and 2010. KCP&L believes that many of the smart grid technologies and functions demonstrated will be key components of the future KCP&L grid, providing more reliable service, reducing operational costs, and enhancing opportunities for consumers to manage their energy costs. KCP&L is using the findings of the project to guide planning for enterprisewide deployments of smart grid technologies.

4.5.1 Mid-Project Go-Forward Assessment

In early 2012 KCP&L began development of a near-term, multiyear (5+) corporate IT Roadmap, and the project team was asked to identify candidate smart grid systems or technologies that should be considered in this planning effort. The team evaluated each technology component to assess perceived value, technical readiness, and potential timing at which enterprise deployment would be viable. This proved particularly challenging, as many of the project components were still under development and had not yet entered the project's operational phase. Figure 4-4 illustrates the findings of the Mid-Project Technology Assessment with the following recommendations.

Figure 4-4: Mid-Project Technology Assessment



SmartMetering — This includes AMI, MDM, and Meter Data Analytics (MDA). All three of these technologies were identified as winners and it was recommended that they be evaluated for incorporation and proper sequencing (along with the planned CIS upgrade) into KCP&L's IT Roadmap.

SmartDistribution — This includes integrated OMS / DMS / D-SCADA / ADA. The SmartDistribution technologies were designated as winners and were recommended for incorporation in the broader KCP&L IT Roadmap. OMS had already been identified as an item for replacement by the organization and there were enough benefits to move forward with these technologies in keeping with the general industry direction. Detailed requirements and vendor selections were to be incorporated early in the corporate strategy effort.

Integration and Cyber Security — The SGDP has shown the importance of proper integration between systems, and just how difficult multisystem integrations can be. Enhanced security, while not required today, is likely on the horizon to be driven by state or federal mandates. As technology continues to advance, KCP&L should seek to apply advanced and standard integration technologies (such as an ESB) wherever and whenever possible, and proactively incorporate additional physical and cyber security measures as part of the broader technology road map.

SmartEnd-Use — This includes HEMP, IHDs, HANs, and public charging stations. While some of these technologies are viable (and others may be viable at some point) the team's recommendation was to discontinue demonstration programs at the end of 2014 (with a web portal solution as a possible exception) and to continue to evaluate select program components for future implementation as technology advances.

SmartGeneration – This includes BESS, DERM, AMI DR PCTs, and Rooftop Solar. While some of these technologies may ultimately be considered winners, it was deemed too early to tell if/when the demonstrated technologies should be considered for implementation.

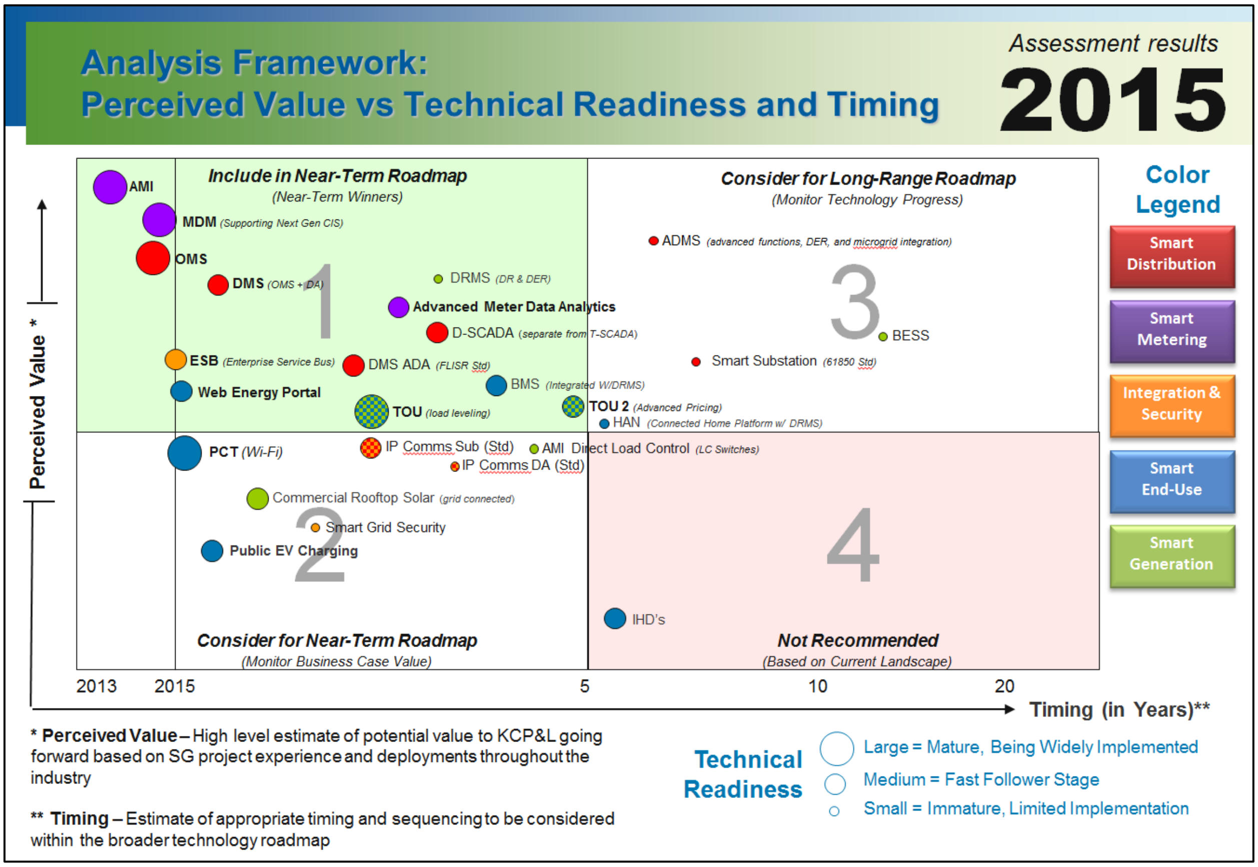
With this input, along with other analysis and considerations, the resulting IT Roadmap incorporated the implementation of a new enterprise integration architecture platform, the upgrade of the OMS, and enterprise deployments of AMI and MDM as prerequisite projects ahead of the planned next generation CIS implementation. Because most of the SGDP systems selections were made in 2009 — prior to the DOE application — KCP&L determined that it would be prudent to re-evaluate all system selections prior to enterprise deployments. Therefore some of the enterprise deployments are going forward with different vendors than were used for the SGDP.

4.5.2 Current Go-Forward Strategies

Over the course of the project operational period and throughout subsequent operational demonstration testing and analysis, the project team accumulated additional insights and knowledge that have been incorporated into subsequent technology assessments and project planning that resulted from the Mid-Project Technology Assessment and IT Roadmap development discussed in the previous section.

With all of this additional learning, the team performed an end-of-project evaluation to reflect current smart grid technology initiatives and again evaluate remaining technologies to assess their perceived value and technical readiness to develop Go-Forward Strategies for each of the components of the KCP&L SGDP. Figure 4-5 illustrates the findings of the End-of-Project Technology Assessment, including go-forward recommendations.

Figure 4-5: End-of-Project Technology Assessment



4.5.2.1 Near Term Initiatives

Several of the SGDP components have been evaluated and approved for enterprisewide expansion. The following smart grid technology deployments are currently underway or planned for the immediate future.

4.5.2.1.1 SmartMetering

AMI (KC Metro) — In 2014, KCP&L began upgrading its legacy AMR system to L+G Gridstream AMI technology for approximately 500,000 customers in the metropolitan Kanas City area. This upgrade will be complete in 2015, and in 2016 an additional 185,000 manually read metro area meters will be added.

MDM — In 2015, KCP&L will be implementing an enterprisewide MDM system as the system of record for all meter information and meter read data. In addition to AMI meters, the MDM will receive meter reads from the MV-90 and hand-held meter reading systems. The MDM is being deployed ahead of, and will provide billing determinants to, the planned next-generation CIS.

4.5.2.1.2 SmartEnd-Use

Web Energy Portal — Leveraging the project knowledge in the SmartEnd-Use area, KCP&L began an energy efficiency paper reports program in 2014. In 2015, this energy efficiency program is being expanded to include a Web Energy Portal for all residential customers.

4.5.2.1.3 SmartDistribution

OMS — In the fall of 2014, KCP&L upgraded its legacy OMS to a state-of-the-art OMS, one incorporating many of the capabilities and functions demonstrated during the SGDP.

DMS — Beyond the SGDP, KCP&L has a fairly extensive DA platform for managing field devices via a public communications network. The second phase of the OMS upgrade will occur when the OMS is integrated with the existing DA platform in 2015, effectively creating a first-generation DMS.

4.5.2.1.4 SmartGeneration

PCT (Wi-Fi) — In 2014, the KCP&L DR PCT program was upgraded from a pager-based technology to a system that uses customer Wi-Fi for communication, providing customers with thermostat control capabilities from a computer or cellphone.

Public EV Charging — In late 2014, KCP&L began construction of the KCP&L Clean Charge Network, which will include more than 1,000 Level 2 and Level 3 public charging stations. The network, along with future EV charging products and services, will allow KCP&L to manage increased EV penetrations and minimize grid impacts. The network should reduce anxiety regarding EV range by providing a charging infrastructure that is both robust and public.

Rooftop Solar — In 2015, KCP&L plans to begin an expanded rooftop solar pilot program with an additional 3-5 MW of utility-owned, grid-connected, rooftop commercial solar installations.

4.5.2.2 Longer Term Strategies

While some of the SGDP technologies are viable today (and others may be viable at some point), they may be dependent on some pre-requisite technology deployments or different economic conditions to become cost beneficial. KCP&L will continue to evaluate these project components for future implementation. The following points outline the SGDP team's current recommendations for the key remaining SGDP technology components demonstrated.

4.5.2.2.1 SmartMetering

AMI (non Metro) — After implementation of the next-generation CIS, KCP&L plans to deploy AMI technology to KCP&L's remaining 160,000 customers outside of the Kansas City metropolitan area, assuming the business case remains favorable.

4.5.2.2.2 SmartEnd-Use

TOU — The SGDP validated the challenges of implementing TOU rates with KCP&L's legacy CIS. The recommendation is that multitier TOU rates be developed and planned for implementation after the next-generation CIS is implemented and a majority of the AMI rollout is complete.

TOU2 — This would include several advanced pricing programs, such as critical peak pricing and real-time pricing. The team projects that these types of pricing programs may have merit at some point; however, they must be carefully constructed and should be considered for implementation after basic TOU rates. AMI, MDM, and next-generation CIS implementations form the foundation for these advanced pricing programs.

HAN — The area of customer home energy automation has been slow to progress, and platform technologies have been rapidly changing. In the near term it appears that providers of connected homes are better positioned to provide such services than a traditional electric distribution utility would be. The project team's current recommendation is that KCP&L use the AMI's capabilities to provide real-time customer meter information to a customer's HAN Gateway, but that KCP&L not be the provider of the home energy automation platform. At some future point, it may become desirable, from a strategic standpoint, for the utility to offer some form of home energy automation/management platform.

4.5.2.2.3 SmartDistribution

DMS-ADA — This proposed Advanced DA initiative would deploy additional automated reclosers, switches, and localized automation schemes targeted at the worst-performing circuits, along with localized areas of lower reliability. The project team believes that by leveraging the existing DA network and first-generation DMS, many issues regarding customer reliability could be addressed — and reliability improved — at a relatively low cost.

D-SCADA — While the project team believes that a dedicated Distribution SCADA system is a foundational smart grid technology and that it will eventually be required at KCP&L, the SGDP identified several significant technology gaps in the current SCADA technology relative to the future smart grid needs. The team recommends that KCP&L continue to monitor the progress of the industry in addressing these gaps and consider deployment of a D-SCADA system once significant progress has been made or when the existing DA platform no longer meets the company's automation needs.

ADMS — The project team believes that an Advanced DMS is a foundational smart grid technology and will eventually be required at KCP&L. However, the SGDP identified several technology gaps in current DMS technology relative to future smart grid needs or managing distributed energy resources and other emerging edge-of-grid technologies. The team recommends that KCP&L continue to monitor the progress of the industry in addressing these gaps and consider deployment of an ADMS system after the deployment of a D-SCADA system and when significant progress has been made or when the existing first-generation DMS no longer meets the company's needs.

4.5.2.2.4 SmartGeneration

DRMS — The project team believes that a Distributed Resource Management System is an integral smart grid technology that will eventually be required at KCP&L for managing DR and DER resources across a growing number of technologies and platform providers. DRMS systems are continuing to expand their capabilities, and the team recommends that KCP&L evaluate inclusion of a DRMS as a platform component in the next round of DR program planning.

Grid Battery — The project team believes that a grid BESS will at some point be cost effective and become a key element of the future distribution grid. The team recommends that KCP&L continue to monitor the economics of BESS and consider BESS application when costs come down and additional benefit streams can be obtained from the wholesale market.

Premise Battery — The project team believes that a Premise Energy Storage System will at some point be cost effective and become a key energy support element for both the customer and the distribution utility. The team recommends that KCP&L continue to monitor the economics of PESS and consider designing DR programs that incorporate them.

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7 ABBREVIATIONS AND ACRONYMS

ACM – Asset Characterization Module
ADA – Advanced Distribution Automation
AHE – AMI Head-End
AMI – Advanced Metering Infrastructure
AMR – Automated Meter Reading
AOS – Alexander Open Systems
BAC – Battery Automation Controller
BESS – Battery Energy Storage System
BMS – Building (Energy) Management System
CAD – Computer-Aided Dispatch
CID – Configured IED Description
CIM – Common Information Model
CIP – Critical Infrastructure Protection (NERC)
CIS – Customer Information System
CLP – Critical Load Panel
CM – Computational Module
CMEP – California Metering Exchange Protocol
CPHE – Customer Pilot Hosting Environment
CSWG – SGIP Cyber Security Working Group
CT – Current Transformer
CVR – Conservation Voltage Reduction
DA – Distribution Automation
DAC – Distribution Automation Controller
DCADA – Distributed Control and Data Acquisition
DDC – Distribution Data Concentrator
DER – Distributed Energy Resource
DERM – Distributed Energy Resource Management
DG – Distributed Generation
DIM – Data Input Module
DLC – Direct Load Control
DM – Distribution Management
DMAT – Data Mining and Analysis Tool
DMS – Distribution Management System
DNA – Distribution Network Analysis
DOE – Department of Energy
DR – Demand Response
DRAS – Demand Response Automation Server
D-SCADA – Distribution Supervisory Control and Data Acquisition
DSE – Data Synchronization Engine
DSPF – Distribution System Power Flow
DSSE – Distribution System State Estimator
DVC – Dynamic Voltage Control
EISA – Energy Independence and Security Act
EMS – Energy Management System
EPRI – Electric Power Research Institute
eRSTP – Enhanced Rapid Spanning Tree Protocol
ESB – Enterprise Service Bus
ESCSWG – Energy Sector Control Systems Working Group
ESCT – Energy Storage Computational Tool
EV – Electric Vehicle
EVCS – Electric Vehicle Charge Station

EVSE – Electric Vehicle Supply Equipment
FAN – Field Area Network
FAT – Factory Acceptance Testing
FCI – Fault Current Indicator
FDIR – Fault Detection, Isolation and Restoration
FDP - Fiber Distribution Panels
FERC – Federal Energy Regulatory Commission
FISR – Fault Isolation and Service Restoration
FLOC – Fault Location
FLT – Feeder Load Transfer
FTE – Full Time Equivalent
GIS – Geographic Information System
GOOSE – Generic Object-Oriented Substation Event
GPE – Great Plains Energy
GUI – Graphical User Interface
GWAC – GridWise Architecture Council
HAN – Home Area Network
HAND – Home Area Network Device
HANG – Home Area Network Gateway
HEMP – Home Energy Management Portal
HIS – Historical Information System
HMI – Human Machine Interface
IBEW – International Brotherhood of Electrical Workers
ICCP – Inter-Control Communications Protocol
IEC – International Electrotechnical Commission
IED – Intelligent Electronic Device
IEEE – Institute of Electrical and Electronics Engineers
IETF - Internet Engineering Task Force
IHD – In-Home Display
IMM – Information Model Management
IP – Internet Protocol
IRP – Integrated Resource Planning
ISO – Independent System Operator
IT – Information Technology
IVR – Integrated Voice Response
JMS – JAVA Messaging Service
KCC – Kansas Corporation Commission
KCP&L – Kansas City Power & Light
KCP&L-GMO – KCP&L Greater Missouri Operations Company
L+G – Landis + Gyr
LCS – Load Control Switch
LTC – Load Tap Changer
MARC – Mid-American Regional Council
MDM – Meter Data Management
MEC – Metropolitan Energy Center
MMS – Manufacturing Messaging Specification
MPLS – Multi-Protocol Label Switching
MPSC – Missouri Public Service Commission
MQ – Message Queues
MUDR – Metered Data Usage Repository
NERC – North American Electric Reliability Corporation
NETL – National Energy Technology Laboratory
NIPP - U.S. National Infrastructure Protection Plan
NIST – National Institute of Standards and Technology
NISTIR – NIST Interagency or Internal Reports

NRC – Nuclear Regulatory Commission
NREL – National Renewable Energy Laboratory
NSPE – National Society of Professional Engineers
OASIS – Advancing Open Standards for the Information Society
OATI – Open Access Technology International
ODR – On-Demand Read
OEM – Original Equipment Manufacturer
OMS – Outage Management System
OMSM – Outage Management Support Module
OpenADR – Open Automated Demand Response
OT – Operational Technology
PAS – Power Automation System
PCM – Project Characterization Module
PCS – Power Conditioning System
PCT – Programmable Communicating Thermostat
PESS – Premise Energy Storage System (battery)
PEV – Plug-in Electric Vehicle
PFP – Pay for Participation
PLC – Programmable Logic Controller
PLP – Project Living Proof
POA – Power Outage Analysis
PoE – Power over Ethernet
PSV – Power Status Verification
PT – Potential Transformer
PV – Photo Voltaic (Solar)
RDBMS – Relational Data Base Management System
RDF – Resource Description Framework
REP - Resilient Ethernet Protocol
REST - Representational State Transfer
RSO – Remote Service Order
RSTP - Rapid Spanning Tree Protocol
RTAC - Real Time Automation Controller
RTO – Regional Transmission Organization
RTU – Remote Terminal Unit
RVA – Restoration Verification Analysis
SAAS – Software-As-A-Service
SAML – Security Assertion Markup Language
SAT – Site Acceptance Testing
SEL – Schweitzer Engineering Laboratory
SEP – Smart Energy Profile
SGAC – Smart Grid Architecture Committee
SGCT – Smart Grid Computational Tool
SGDG – Smart Grid Demonstration Grant
SGDP – SmartGrid Demonstration Project
SGIG – Smart Grid Investment Grant
SGIP – Smart Grid Interoperability Panel
SICAM – Siemens Integrated Control and Monitoring
SIS – Solar Integration System
SLPB – Superior Lithium Polymer Battery
SME – Subject Matter Expert
SMS – Storage Management System
SOA – Service-Oriented Architecture
SOAP – Simple Object Access Protocol
SPID – Service Point Identifier
SPM – Switching Procedure Management

SPN – Substation Protection Network
SPP – Southwest Power Pool
SSO – Single Sign-On
T&D – Transmission and Distribution
TOU – Time of Use
TPR – Technology Performance Report
TTM – Tunnel Text Message
UCAIug – UCA International Users Group
UI – User Interface
USABC – U.S. Advanced Battery Consortium
VAR – Volt-ampere reactive
VCMS – Electric Vehicle Charge Management System
VEE – Validation, Estimation and Editing
VVC – Volt/VAR Control
W3C – World Wide Web Consortium
WAN – Wide Area Network
WASA – Wide Area Situational Awareness
WS-I – OASIS Web Service Interoperability
XML – Extensible Markup Language

8 APPENDICES [32]

Appendices were published in separate document entitled

KCP&L Green Impact Zone SmartGrid Demonstration Final Technical Report Appendices.

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