EPRI | ELECTRIC POWER RESEARCH INSTITUTE

EPRI SMART GRID DEMONSTRATION INITIATIVE

FINAL UPDATE

Table of Contents

The Smart Grid Demonstration Initiative Final Update 2

Conservation Voltage Reduction, Ameren 4

Simulation of Community Energy Storage, American Electric Power 6

Multiple Technology Aggregate Response, American Electric Power 8

Managing Technologies and Applications on a Distribution System, American Electric Power 10

Remote Dispatch of Customer-Owned Resources, Consolidated Edison 12

Assessment of Achieving Increased Reliability with Distributed Energy Resources, Consolidated Edison 14

Demand-Side Uses of a Thermal Storage Plant, Consolidated Edison 16

Approaches to Self-Healing Networks, Duke Energy 18

A Utility-Scale, Single-Customer Microgrid at Duke Energy 20

The Response Precision of PREMIO Virtual Power Plant, Electricité de France 22

Deferring Asset Investment with Distributed Energy Resources, Ergon Energy 24

Smart Green Circuits at ESB Networks 26

Smart-Meter Customer Behavior Trial, ESB Networks 28

Distribution Volt-Var Control Integrated with Wind Turbine Inverter Control, ESB Networks 30

Impact of Advanced Metering Infrastructure (AMI) on Demand Response – Commonwealth Edison Smart Grid Demonstration, Exelon 32

Drexel Smart Campus – PECO Smart Grid Demonstration, Exelon 34

Integrated Distributed Energy Resources Management: Device Installation and Commissioning, FirstEnergy 36

Integrated Control Platform Visualization, FirstEnergy 38

PJM Market Program Participation, FirstEnergy 40

Electric Power Distribution Modeling and Simulation for Feeder Analytics and Distributed Energy Resource Integration, FirstEnergy 42

Interconnection Requirements Study for Battery Energy Storage Systems on Maui Electric's 12.47 kV Distribution Circuit, HECO 44

Anti-islanding Protection of Distributed Generation using Autoground, Hydro-Québec 46

Testing and Certification of Equipment for a Volt-Var Control Application, Hydro-Québec 48

Evaluating the Protection Impacts Associated with the Integration of a Wind Park on the Distribution System, Hydro-Québec 50

Evaluation of Solutions for Limiting Transformer In-rush Currents of a Distribution Connected Wind Park at Hydro-Québec 52

Customer Acceptance and Technology Adoption, Kansas City Power & Light 54

Customer Engagement for Multiple Smart Grid Products and Treatments, Kansas City Power & Light 56

Residential Demand Response Standards and Interoperability, Kansas City Power & Light 58

Use of Storage for Simultaneous Voltage Smoothing and Peak Shifting, 2013 Update, Public Service of New Mexico 60

PV Smoothing Using Coordinated Control of a Battery and Gas Generator & Fuel Cell, Public Service Company New Mexico 62

Conservation Voltage Reduction and Volt-Var Optimization, Sacramento Municipal Utility District 64

Residential Summer Solutions, Sacramento Municipal Utility District 66

Summer 2013 Analysis of Sacramento Municipal Utility District Conservation Voltage Reduction (CVR) Tests 68

The SmartPricing Options Pilot at the Sacramento Municipal Utility District 70

The 2013 PowerDirect® Automated Demand Response (AutoDR) Pilot Program, Sacramento Municipal Utility District 72

SMUD Revenue Protection Software, Sacramento Municipal Utility District 74

The PowerStat Study Conducted at Sacramento Municipal Utility District 76

A Field Area Network (FAN) Pilot at Salt River Project 78

Distribution Volt-Var Control to Optimize Customer Voltage: Irvine Smart Grid Demonstration, Southern California Edison 80

Substation Automation: Irvine Smart Grid Demonstration, Southern California Edison 82

Cyber Security at Southern California Edison 84

A Capacitor Bank Health Monitor, Southern Company 86

The Effects of Capacitors on Substation Bus Voltage, Southern Company 88

Peak-Time Voltage Reduction Analysis Case Study at Georgia Power – A Southern Company 90

2013 Conservation Voltage Reduction Analysis Case Study at Alabama Power – A Southern Company 92

Analysis of Power Quality Impacts during Conservation Voltage Reduction (CVR) at Georgia Power – A Southern Company 94

Self-Healing Networks at Southern Company 96

The EPRI Smart Grid Demonstration Initiative Team 98

Index 100

What is the EPRI Smart Grid Demonstration Initiative?

The Smart Grid Demonstration Initiative is a seven-year collaborative research effort to design, deploy, and evaluate how to integrate distributed energy resources (DER) into utility grid and market operations. The Initiative leverages multi-million dollar investments in the smart grid by the electric utility industry, with the goal of sharing information and research results on a wide range of smart grid technologies and applications. Twenty-four utilities from Australia, Canada, France, Ireland, Japan and the United States are collaborating in the Initiative.

The Smart Grid Demonstration Initiative Final Update

This update of research results from the EPRI Smart Grid Demonstration Initiative is a collection of 48 case study summaries produced by 17 collaborating and host utilities in the Initiative.

These case study briefs feature lessons learned from field demonstrations and cover a range of experiments and deployments, from investigation of distribution system voltage control to customer behavior to performance of emerging information and communication technologies. Experience in developing or using methods and standards for designing, building, and operating a smart grid are also highlighted.

Research conducted as part of the seven-year Smart Grid Demonstration Initiative ends in 2014. This Final Update documents findings as of mid-2014 for multiple projects related to the integration of distributed energy resources.

Our international collaboration has allowed us to tap into world-class expertise and valuable, real-world experience. Experts in multiple scientific disciplines are engaged in analysis of research results, and all of the participating utilities have important information and findings to share. This information is documented in the full-length versions of the case studies summarized in this document, as well as in progress reports, white papers, webcast recordings and other reference materials. These resources can be downloaded at www.epri.com and many are publicly available at no cost. Reports are scheduled for publication through the first quarter of 2015; you can view a periodically updated list of all of the materials delivered at www.smartgrid.epri.com/.

In addition to this Final Update and other documentation of research results, EPRI has created or been strategically engaged in the creation of resources that can support the electricity industry in making business and technical design decisions about the smart grid and grid modernization:

- A cost-benefit analysis framework – Co-funded by EPRI and the U.S. Department of Energy (DOE), a *Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects* was developed as well as a practical guidebook on the step-by-step process for estimating the costs and benefits associated with smart grid demonstration projects. The cost-benefit framework was created to help yield experimental results that will advance our understanding of where, how, and under what conditions (grid characteristics, market structures, climate, system operating conditions, etc.) the various systems can be expected to perform. The framework report (product number 1020342) and the guidebook (product number 3002002266) are publicly available at no cost.
- A distributed energy resources architecture that served as the foundation for OpenADR – EPRI presented *Concepts to Enable Advancement of Distributed Energy Resources* (product number 1020432) in 2010. The concept architecture proposed that "smartness" for the power grid could reside at end nodes, where information exchanged between a resource controller and individual devices or systems would modify energy consumption. This concept helped guide basic architectural principles developed in Open Automated Demand Response (OpenADR), an interoperable information exchange model and emerging smart grid standard. OpenADR specifies the message format used so that dynamic price and reliability signals can be exchanged in a uniform and interoperable fashion among utilities, independent system operators, and energy management and control systems.

- **Contributions to CEA-2045** – EPRI was instrumental in the initiation of a modular communications interface to facilitate communications of energy management signals to reach devices that range from appliances and consumer products to energy management gateways and controllers. Open source software, produced for OpenADR by EPRI, contains a reference implementation of CEA-2045 that manufacturers can incorporate into residential devices as a cost effective way for products to be made smart-grid ready. Such an interface can provide the flexibility needed to employ networking equipment of one's own choosing, and could help prevent appliance obsolescence related to changing communication technologies. EPRI's Field Demonstration of CEA-2045 Standard Modular Interface for Demand Response (product number 3002000450) is a current project to deploy products incorporating CEA-2045 in field environments or operate them in active demand response programs
- **Smart inverter standards** – EPRI has engaged inverter manufacturers, system integrators, utilities, universities, and research organizations in a collaboration to provide smart inverter function descriptions to standards development organizations, documented in the EPRI report *Common Functions for Smart Inverters* (product number 3002002233). The process of developing a complete design specification for a smart photovoltaic, battery-storage, or other inverter-based system may be greatly simplified by taking advantage of this body of collaborative industry work.
- **A use case repository** – Software and other high-technology companies have employed "use cases" to identify and document project requirements for many years. EPRI 's IntelliGrid program developed a use-case methodology that is adapted for the electric power industry, and numerous utilities used this methodology as an initial step in designing smart grid projects. For example, use cases were a critical first step for Public Service Company of New Mexico for creating controls and data collection systems for its photovoltaics plus battery project (see page 60), and use cases helped Kansas City Power & Light's define the processes, integration, and data flows needed to schedule and implement demand response events (see page 58). EPRI has compiled a Use Case Repository with more than 200 use cases and requirements developed within the industry as well as through the Initiative. This resource is available to the public at no cost at www.smartgrid.epri.com/.
- **Training videos on key smart grid topics** – DVDs of training sessions held at EPRI Smart Grid Demonstration Advisory meetings during the past several years are available to Initiative participants as part of their membership and to others for a fee. Taught by top subject-matter experts from EPRI, the training sessions cover advanced distribution management systems, utility-grade communications systems, cyber security, voltage reduction/volt-var optimization, cost-benefit analysis, system protection, standard IEC-61850, and smart inverters. The DVD's can be ordered online at www.epri.com.

EPRI is pleased with the exceptional work conducted by the utilities in the Smart Grid Demonstration Initiative. Findings and lessons from the demonstrations will help define state-of-the-art practices for building a smarter grid. On behalf of the electric utility members and EPRI technical staff, we invite you to learn more about these results and thank all those who have contributed to these important lessons.

Sincerely,

Matt Wakefield

Director, Information Communications & Technology

Gale Horst

Sr. Project Manager, Smart Grid

Ameren Illinois

Different CVR capabilities are attainable during summer and fall, and accounting for large episodic changes in feeder loads is a critical aspect of performing the CVRf analysis.

Ameren Illinois Smart Grid Demonstration Project consists of two projects focused on determining the effects of conservation voltage reduction on two distribution systems within Ameren Illinois service territory. The results of this testing will provide the basis for future conservation voltage reduction projects as a part of Ameren Illinois smart grid technology rollout.

Ameren Illinois Case Study on Conservation Voltage Reduction

Beginning in April of 2012, Ameren Illinois conducted tests to determine the effects of conservation voltage reduction (CVR) on a highly loaded urban distribution circuit as well as a combination urban/rural distribution circuit.

CVR is a reduction of voltage along the distribution feeder for the purpose of reducing electric power demand and energy. By reducing the voltage along the feeder a few percentage points, but keeping the delivery voltage in the acceptable range of 114-126 volts, demand and energy are reduced while still providing adequate voltage for customer usage.

Testing

Ameren Illinois tests included the following system enhancements: installation of new regulator controllers with two-way radio communications, installation of voltage sensors at end-of-line locations, modifications to LTC controller to provide remote control capabilities, and implementation of automatic voltage control using Ameren's new ABB SCADA system.

CVR was tested by Ameren Illinois on four feeders to determine energy savings as well as peak demand reduction. The test feeders are served from two distinct substations in Ameren Illinois' service territory, one designated as the Urban substation, the other as the Rural/Urban substation.

The Urban test involved three circuits and included varying the set point on the load-tap-changing (LTC) transformer for 24-hour periods at voltage reduction levels of 0% (normal), 2% and 4%.

The Rural/Urban substation test involved one circuit and included modification to all voltage regulator set points (six sets), including the substation feeder regulator, for 24-hour periods at levels of 0%, 2% and 4% voltage reductions.

Data was collected at the test circuits' feeder heads as well as the feeder heads for nearby comparable circuits. (A feeder in a separate substation was selected for comparability with the Urban substation test circuit, but a different circuit in the same Rural/Urban substation was selected for comparability in the Rural/Urban test).

Project Hypothesis

The key project hypothesis being tested is that demand is reduced and energy savings increased as the normal voltage is reduced by 2-4%.

Results

Analysis of testing results demonstrated that different CVR capabilities are attainable during different periods of time. This aspect is demonstrated as follows, with the results expressed in terms of the Conservation Voltage Reduction Factor, or CVRf. The CVRf is defined as the percent reduction in load obtained per percent of voltage reduction. For example, if load is reduced 2% from a voltage reduction of 3%, then the CVRf is 2%/3%, or .67.

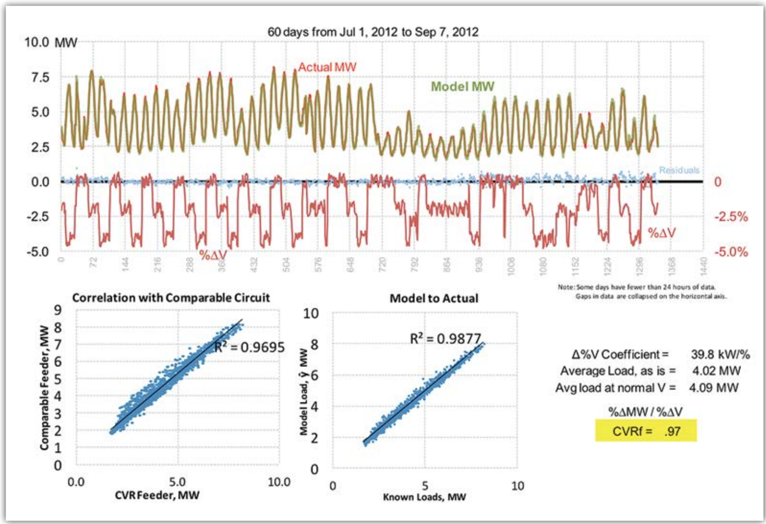
Comparison of the values below to values attained by other utilities demonstrates that Ameren Illinois testing results are comparable to the national average of a CVRf of 0.8.

Estimated CVRf		
Feeder	**Summer**	**Fall**
Urban	.78	1.24
Rural/Urban	.97	.44

Methodology

The CVR-feeder loads were analyzed with a statistical regression procedure that used the comparable feeder as a key independent variable along with time-of-day and day-of-week variables. Holidays and other feeder events were also associated with dummy variables. Hours were eliminated from the analysis if any of the required data items were missing or clearly in error. Though two different voltage-reduction levels were tested, the initial analytic procedure obtained a single average impact per percent of voltage reduced. The data was analyzed monthly and seasonally.

While the comparable feeders were highly correlated with the CVR feeders during the summer months, the correlation deteriorated in the fall months. The trouble was traced to several agricultural loads that became active in late summer, running sporadically during the fall. At their peaks, they were individually large relative to the total feeder load at the time. The loads were on both the CVR feeder and the comparable feeder, but they were not correlated with each other or with daily weather patterns.



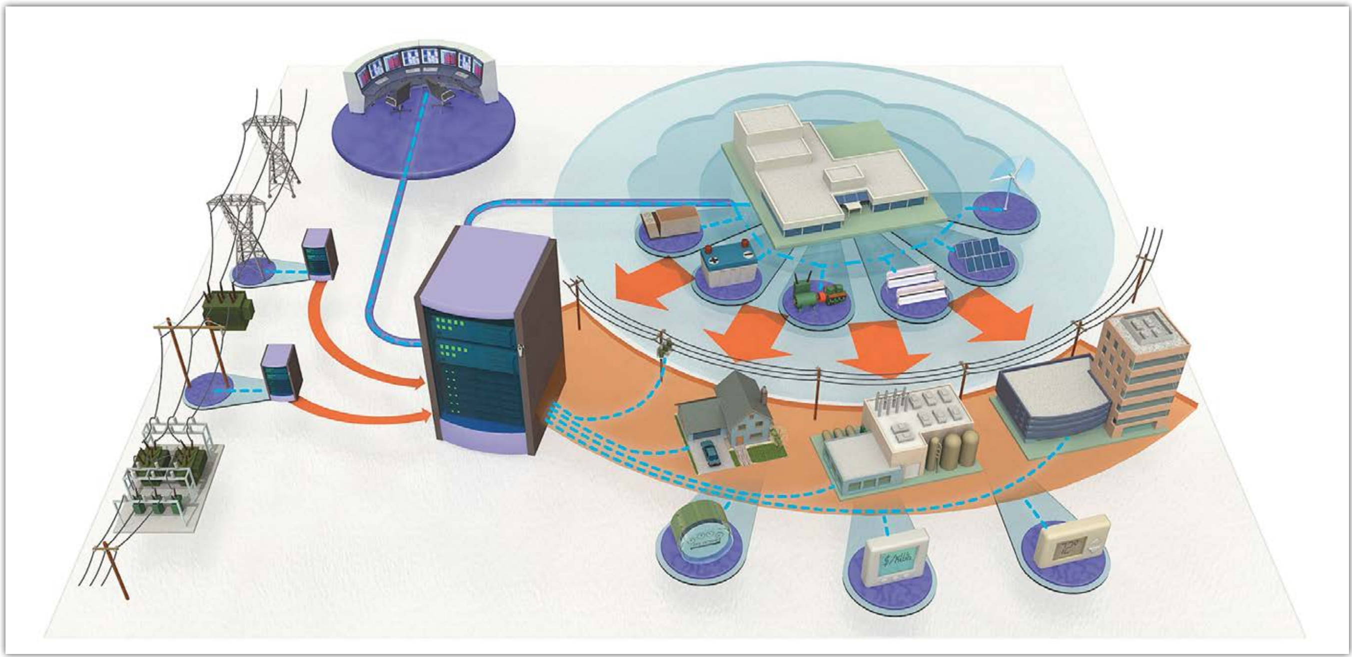
The CVR regression analysis methodology was used to attempt to extract a small impact from feeder loads by exploiting daily and weekly patterns that a feeder may exhibit, but the presence of such large episodic loads on the feeders rendered this method ineffective unless these loads could be explicitly accounted for. The team was able to obtain hourly meter readings for the loads and subtract them from the total feeder loads, and the remaining feeder loads were then analyzed. Residual impacts of the agricultural loads on voltages and losses were not readily detectable, and the regression results were within the expected range.

Lesson Learned

- Understanding the feeder load characteristics is a critical aspect of performing the CVRf analysis. During the testing process, additional load was added to the comparable circuit for the Urban feeder test. Seasonal grain elevator loads on both of the Rural/Urban circuits (test circuit and comparative circuit) created data analysis issues until the seasonal load was identified and addressed.
- Additional testing is necessary in order to understand the effects of CVR throughout all seasonal conditions.
- Statistical comparison of a CVR feeder with a similar non-CVR feeder can change in effectiveness from month to month:
  - Load shapes may be similar in hot weather peak months, but may differ in other periods.
  - If the comparable feeder approach fails, then weather data may be useful for use in the regression analysis.

For the full case study, search www.epri.com for product number 3002002246.

American Electric Power



Dispatch of energy storage based on monitored kW will reduce the number of battery charge/discharge cycles needed to shift the peak demand.

The AEP Smart Grid Demonstration Project is assessing distributed energy resources and technologies that can serve collectively in a manner similar to a physical power plant. These resources include a mix of distributed generation, energy storage, and demand response systems that make it possible to meet demand or shift loads.

Case Study on Simulation of Community Energy Storage

AEP is installing 80 community energy storage (CES) batteries on a distribution circuit and is controlling them as an aggregated fleet for a total of 2MWh of storage. Each unit is small (25 kVA, 25 kWh) and connected to the secondary of a transformer serving 2-5 houses.

Simulations were used to study various charge and discharge strategies as a means of evaluating benefits and system conditions surrounding use of this storage—an assessment that would otherwise be too costly.

Evaluation was based on data from the actual feeder selected for field deployment of the CES units. The study circuit is a 13.2 kV circuit serving a primarily residential load with peak demand of 5.8 MW. Fifteen-minute interval data from 1,795 advanced meters on the target circuit were used for the study.

The simulations focused on two key components: the storage unit itself, and the energy storage controller. The algorithms were modeled and simulated on the target circuit by using the OpenDSS (Open Source Distribution System Simulator).

Project Hypotheses

The simulation study focused on three hypotheses:

- A plurality of community energy storage units, installed on the secondary side of the distribution service transformer, can respond as an aggregated fleet in a manner similar to a substation battery.
- OpenDSS can be configured to accurately model/simulate the impacts and benefits of CES units on an electric distribution circuit when verified and compared with an actual deployment on the same circuit.
- Based on circuit needs measured at the substation, a fleet of CES units can be dispatched by the energy storage controller for an effective response.

The simulation utilized OpenDSS to examine three potential discharge modes and assumed a simple charging control at a flat rate occurring during early morning hours. The three types of discharge algorithms studied were:

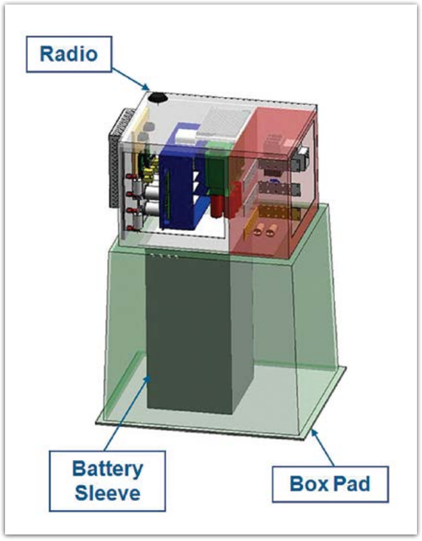
- Peak shaving – The control attempts to discharge the storage to keep the power consumption below a maximum kilowatt value.
- Load following – At a specified time each day, if monitored demand exceeds a pre-determined minimum threshold for discharge, the storage units are dispatched.
- Schedule based – The properties of power ramp-up (minutes), flat duration (hours), and ramp-down (minutes) are used to define a discharge profile that occurs each day starting at a specified time.

Results

A pros-and-cons comparison of the three evaluated peak demand management strategies is shown in the table. These pros and cons apply to strategies for addressing peak demand and did not consider the potential correlation between high demands and outage events to determine the ramifications of different control strategies on reliability.

Qualitative Control Strategy Summary

	Pros	Cons
Peak Shaving	Fixed kW peak Operation directly targets peak demand periods	Risk that required kWh will exceed the stored kWh Requires periodic review of control settings
Load Following	Operation directly targets peak demand periods Reduced risk that the required kWh exceeds stored kWh	Peak demand limit is variable Dependent upon load shape characteristics Requires periodic review of control settings
Schedule Based	Control settings require minimal periodic updates No additional monitoring Central control not required	No preset demand limit Battery fully discharged each day to ensure reduction of the peak Long shallow discharge profile required to confidently reduce peak



Lessons Learned

Observations from the simulations include:

- Peak demand reductions can be achieved with any of the three evaluated discharge strategies. However, to manage the risks of having inadequate storage to ride through the peak—or of having excessive charge/discharge cycles—requires periodic review of algorithms and detailed load profile analysis and projections.
- Direct dispatch of energy storage based on monitored kilowatts will limit the operation of the community energy storage units to peak demand periods, significantly reducing the number of battery charge cycles. This minimizes efficiency losses, and increases the periods of time the units are fully charged so that they are available for reliability support.
- Minimal changes to the primary voltage profile are expected given the assumed amount of distributed energy and power injection limits.
- Negligible impacts to customer voltages or secondary loading are expected given the assumed battery locations and charge/discharge operations.

The simulations of community energy storage control strategies have furthered the understanding of various charge/discharge algorithms. However, as additional grid modernization technology is added to the circuit or end-use locations, it is uncertain how new technologies will affect the operation of the storage units. It is conceivable that the addition of other technologies could necessitate a change in optimal storage operation. Additional simulations that deal with the concurrent operation of several technologies, including community energy storage, are planned as part of the AEP smart grid demonstration.

For the full case study, search www.epri.com for product number 1026436.

American Electric Power

Addition of a new grid technology, such as a volt-var optimization system or community energy storage, will impact the control strategy (controls or settings) of the existing and/or the new technology.

Case Study on Multiple Technology Aggregate Response

This study was designed to gain an understanding of the potential impacts of operating a combination of smart grid technologies and resources at the same time. The AEP/EPRI project team developed a process to determine and manage the impact of concurrent operation of several technologies, including electric vehicles (EVs), community energy storage (CES), and photovoltaic (PV) generation systems.

Part of the study is assessing the data from each technology that can be used to help inform decisions about managing the system as a whole. For example, if an EV and CES system are active at the same time, what data from the EV configuration and dynamic data on EV operation will be helpful in managing the CES technology? Other considerations addressed are the impact of one technology on the other, such as how one technology can enhance or extend the value of another—as well as the potential of one of a combination of technologies to negate or reduce the benefit of another.

Project Hypotheses

The hypotheses tested in the study included:

- Operation of two or more systems on the same circuit, such as CES, volt-var control systems, PV, or EV, will necessitate a change in dispatch or control system algorithms.
- Technologies can be identified that, when operated concurrently, provide value beyond what can be achieved by either individual technology.

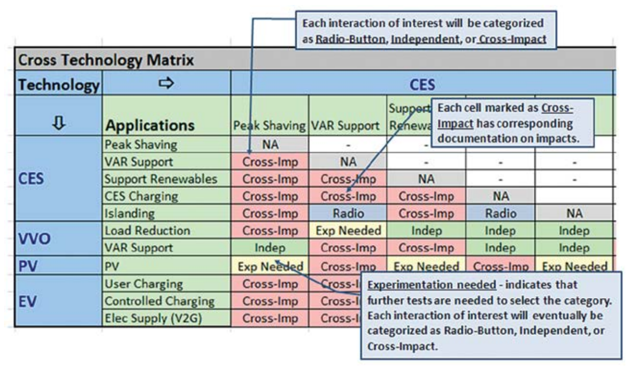
The Process

Two key spreadsheets were developed as tools to support the process, a Technologies Controls Matrix and a Cross Technology Matrix:

Technology Controls Matrix	
<Technology Name>	
Parameter	**Type**
Dispatchable Energy (kWh)	Controllable
Dispatchable Load (kWh)	Controllable
Charge Requirements	Controllable
Active Power (kW)	Controllable
Active Power Limits (kW)	Static
Reactive Power (kvar)	Controllable
Reactive Power Limits (kvar)	Dynamic
Interconnection Status	Static

Figure 1

1. Technologies Controls Matrix – The AEP team identified common data parameters that could be used across various technologies. The next step was to classify, for each technology, whether data is static or dynamic, and whether output could be controlled. This helps identify what values change over time and what can and can't be controlled.
2. Cross Technology Matrix – This spreadsheet, shown in Figure 2, is used to identify the types of interactions expected between two technologies. This matrix and corresponding documentation indicates where interactions may be of concern or in need of further study. It is a working document, meant to be updated as the team progresses through the process steps.



Cross Technology Matrix						
Technology	⇨	CES				
⇩	Applications	Peak Shaving	VAR Support	Support Renewa		
CES	Peak Shaving	NA	-	-		
	VAR Support	Cross-Imp	NA	-	-	-
	Support Renewables	Cross-Imp	Cross-Imp	NA	-	-
	CES Charging	Cross-Imp	Cross-Imp	Cross-Imp	NA	
	Islanding	Cross-Imp	Radio	Cross-Imp	Radio	NA
VVO	Load Reduction	Cross-Imp	Exp Needed	Indep	Indep	Indep
	VAR Support	Indep	Cross-Imp	Cross-Imp	Indep	Indep
PV	PV	Exp Needed	Cross-Imp	Exp Needed	Cross-Imp	Exp Needed
EV	User Charging	Cross-Imp	Cross-I			
	Controlled Charging	Cross-Imp	Cross-I			
	Elec Supply (V2G)	Cross-Imp	Cross-I			

Figure 2

The green column and row in the Cross Technology Matrix represent applications that utilize the technology, indicating the potential for using the technology for more than one purpose. In most cases, applications become the focus of the interactions rather than the technology or device itself. Each interaction is marked as Independent, Cross-Impacted, or Radio-Button (cannot operate concurrently). If an interaction cannot be determined, it is marked as Experiment Needed to point out that further research is needed for classification.

Process Steps

1. Select the technology to be included in the study. Or as an alternative approach, select the desired goal(s) or application(s) (such as peak demand reduction) to identify what technology will be needed to support goal.
2. Review which technologies support the goal (target technology) and include them in the Cross Technology Matrix.
3. In the Cross Technology Matrix, include any other technologies that will be on the same circuit that could be impacted by or cause an impact on the target technology.
4. Place each technology into the Technology Controls Matrix. For each technology, start with the proposed standard parameters, and determine for each what information is available, fixed, and controllable.
5. In the Cross Technology Matrix, identify which cells/ interactions are of interest.
6. Use simulation or actual study and measurement to determine impacts of adjusting the controls.
7. Document results of each cell studied.

Results – Sample Application of the Process

The interaction between a conservation voltage reduction (CVR) application (using a VVO system) and a peak shaving application (using CES) was selected for further study via simulation. As shown in the upper left line graph in Figure 3, CES could not ride through the peak demand period. However, when VVO, shown in the upper right line graph, is combined, concurrent activation of these two applications allows a more successful or larger peak shaving impact than is achievable by using either technology alone (bottom line graph). In this case, the "cross-impact" can be controlled in a beneficial manner.

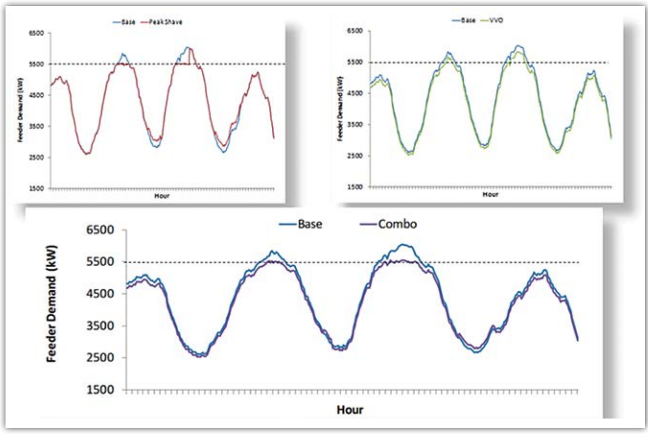


Figure 3 – Cross technology operation – demand response over 3-day period

Lessons Learned

- The hypothesis that "concurrent operation of two or more systems on the same circuit…will necessitate a change in dispatch or control system algorithms" was confirmed in the case of the sample application of the process.
- The hypothesis that "technologies can be identified that, when operated concurrently, provide value beyond what can be achieved by either individual technology" was proven by test of interactions between the volt-var optimization system and the community energy storage used for peak shaving and load reduction.

Next Steps and Recommendations

Prioritization of applications and technology is reliant not only on technology interactions and control options but also upon business operational strategy. A future research project will extend research to include business and operational rules in an effort referred to as "cross-utilization." This study will outline an approach to decision making for dispatching new technologies that includes factors such as business strategy, weather, history, and risk management.

For the full case study, search www.epri.com for product number 3002001965.

American Electric Power

The project team developed a theory of operation and design of a control dispatch system that can result in a workable approach to cross-utilization—a way to prioritize applications served by DER technologies.

Managing Technologies and Applications on a Distribution System

This white paper covers a process that should provide an efficient and scalable approach for cross-utilized distributed energy resources (DER). It is considered a white paper rather than a case study because the approach described is in a conceptual stage rather than in a demonstration stage.

Issue Definition

As technology is selected and installed onto an electrical distribution system, it has traditionally been selected and operated to achieve a specific purpose as envisioned by planners, engineers, and operators. The process of cross-utilization considers situations where a technology could be used for more than one utility application. A utility application refers to the intended business use of DER to address a system need.

A single technology may be involved in applications that address more than one system need, as shown in Figure 1. When a technology provides all or any part of the solution to more than a single system application, this is referred to as cross-utilization. An application that uses technology that may also be called upon as a part of another application is determined to be "cross-utilized."

Cross-utilization can reduce cost and avoid having under-utilized equipment or equipment with an overlapping purpose. However, although several applications could benefit from using the same resource, this could cause competition for the use of that DER technology or system.

An approach to making the appropriate decisions regarding the dispatch of a cross-utilized DER will need to take into account business, economic, forecast, and other input, to appropriately prioritize utilization of the DER. Developing an approach to managing this cross-utilization was the focus of this study.

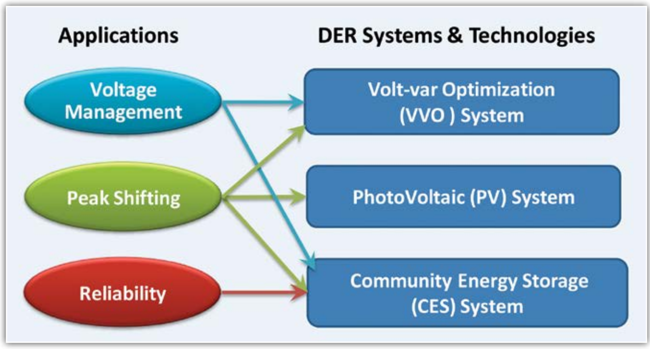


Figure 1 – Cross-utilization diagram

Although cross-utilization could be managed with individual controls, the coordination between various DER control systems would quickly become cumbersome and prone to error because of system conflicts. To create a smart grid requires that DER devices communicate. This communication enables development of methods to manage resources across business applications.

Project Hypotheses

- Information about the configuration and/or operational measurements of one technology can be utilized to optimally manage concurrent operation of another.
- A system with multiple technologies utilized by multiple applications will achieve better optimization and utilization with a master coordinating system (MCS).
- Cross-utilization can be designed as an automatable process.
- A system can be designed whereby several applications can utilize the same technology (or devices) to achieve business purposes or goals by appropriately prioritizing the applications.

Research and Results

The research team recognized the need to represent a comparative value of running different applications that utilize DER. The term Business Energy Analysis Notation (BEAN) is proposed to represent the value of a particular application at a specific point in time. This is used to evaluate the priority of dispatching one application versus another. A coordination system can give one or more applications the clear-to-operate (CTO) for a time interval, identified as delta-t (Δt). At the beginning of each time interval, the process re-evaluates the priorities. This approach allows a master coordination system (MCS) to use the BEAN values, along with other system inputs, to determine which applications are given the CTO signal. Figure 2 diagrams the main execution loop of a total system that manages cross-utilized applications in the manner described.

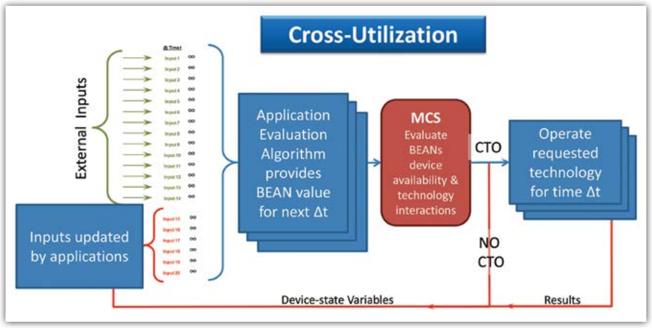


Figure 2 – Application system control loop

By considering a multi-sided balance scale, as diagrammed in Figure 3, the process can manage a number of applications that are competing for the same resources.

Suggested steps to define the cross-utilization application system:

A. Determine which technologies, applications, and combinations of technologies/applications are to be included in the system.

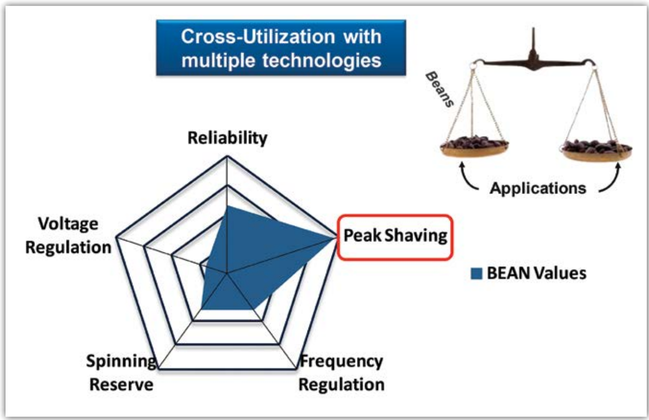
B. Document the various inputs (such as forecasting, business, and device feedback) that will influence each application and combination. This may include inputs/parameters from the "controls matrix" as described in the *A Case Study on Multiple Technology Aggregate Response* (EPRI product #3002001965).

C. Associate the inputs to the Application Evaluation Algorithms. This determines what inputs will be utilized by each algorithm. Some inputs may be associated with more than one algorithm.

D. Develop the Application Evaluation Algorithms based on the business and system goals in conjunction with the inputs available.

E. Determine how often the process needs to update the data and execute the loop in Figure 2. Note that an unusual occurrence on the system will cause an operational interruption that results in an immediate re-execution of the main loop to recalculate the BEANS and re-establish the application priorities.

F. Develop the MCS evaluation logic procedure to evaluate BEANs, and other data to determine which application(s) will be given the CTO.



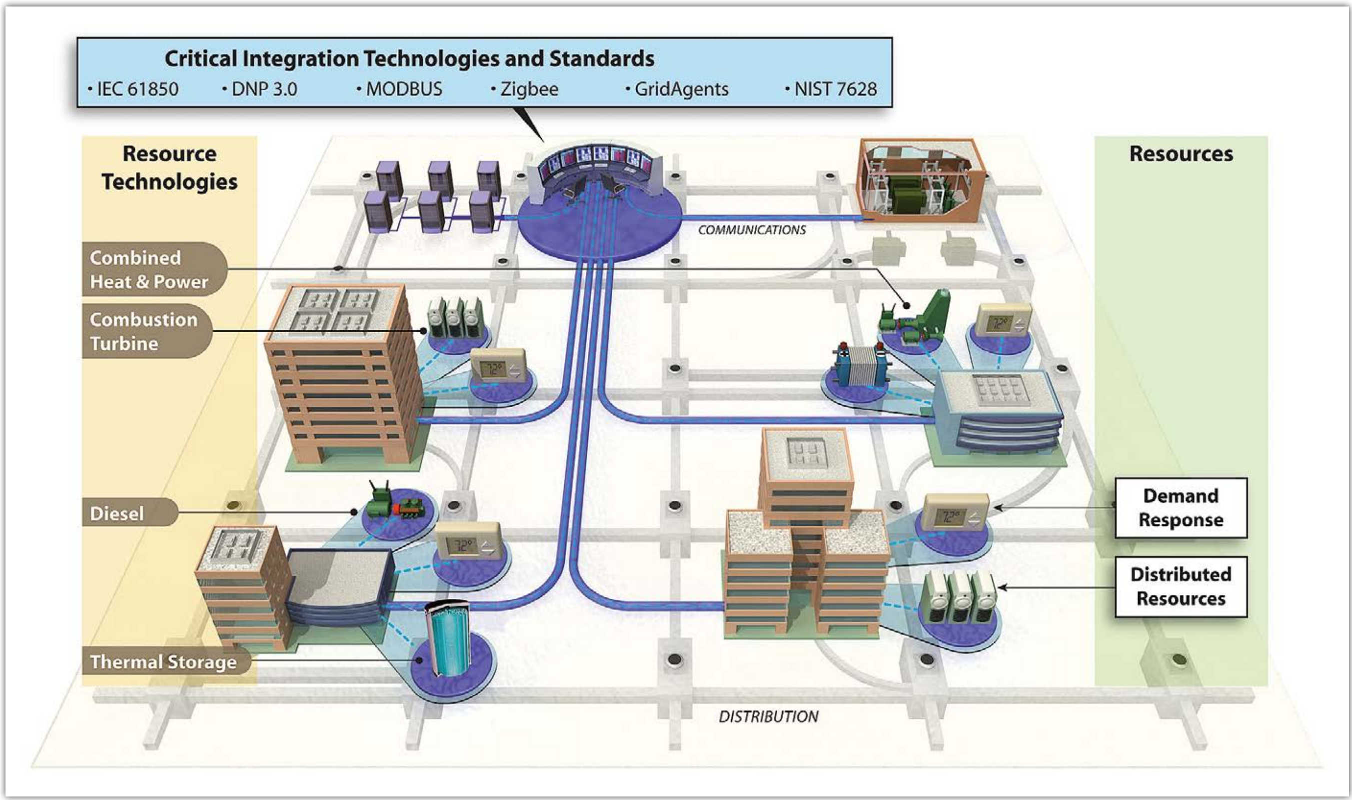
BEAN = Business Energy Analysis Notation, the value of a particular application at specific point in time
Figure 3 – Cross-utilization balance scale

Lessons Learned

- Reviewing the theory of operation and design of a control dispatch system uncovers numerous issues and complexities but results in a workable approach to cross-utilization.
- What could otherwise become a complex process of dissimilar systems can be implemented in a standardized approach resulting in a scalable system.
- A distribution management system (DMS) may benefit from implementation of a coordination system as described in this white paper.
- The team believes the method described in this white paper will provide beneficial results and may save time in scaling up a virtual power plant (VPP) system.

For the full white paper, search www.epri.com for product number 3002004390.

Consolidated Edison



Distribution operators can quickly and remotely activate customer generation resources. This has occurred within 3 minutes, and faster response is anticipated when customer acknowledgement is fully automated.

The Con Edison Smart Grid Demonstration Project is focused on developing the technology necessary to integrate distributed resources into the utility's distribution system and distribution control center. To accomplish this, the project has demonstrated a Demand Response Command Center (DRCC) interface that provides a link between the utility's Distribution Control Center (DCC) and customer-owned distributed resources. The DRCC will provide the distribution operator with increased visibility and access to customer-owned resources, such as energy storage systems and distributed generators. These resources can be utilized to alleviate congestion or respond to potential issues on the distribution system network. In addition, this information enables better planning and early response to real and potential problems on the distribution system and may help extend the life of assets by enabling operators to reduce overload conditions.

The DRCC can:

- Receive curtailment "trigger" signals for both reliability and market programs.
- Activate demand response resources in response to triggers.
- Provide a communication gateway between demand response resources and distribution operators.
- Notify stakeholders of changes in status.
- Aggregate a diverse portfolio of demand response and distributed generation resources.

Remote Dispatch of Customer-Owned Resources

This case study describes the implementation of a key component of a virtual power plant (VPP), an automated demand response application for the remote dispatch of distributed customer-owned resources. This application is essential to the primary goal of the project: to economically harness customer-owned distributed resources and better integrate them into the Con Edison distribution system. In addition to measurable benefits for Con Edison from gaining dispatchable demand response resources, the implementation of a VPP allows the aggregation of multiple demand response and distributed generation resources that can participate in electricity markets on par with generation. The system will also enable third-party aggregators to bid customer-owned resources into market-based programs administered by the independent system operator (ISO).

The automated demand response application was tested in late 2011 and early 2012 at facilities of Verizon, a partner in the project. The application and system performed successfully. The distribution operator was able to identify and activate targeted distributed resources from the distribution operator's interface.

Project partner Verizon created an application on the phones carried by their building managers. This application gives facility managers a view into the status of the building resources with the ability to manage the buildings during the system tests.

The system testing focused on three hypotheses:

- Customer-owned distributed generation can create measurable benefits for Con Edison by becoming a resource dispatched externally as a form of demand response.
- Dispatchable customer-owned distributed generation can create measurable benefits for the NYISO as a reliability resource.
- Distributed resource owners would participate in programs to allow the utility to activate their resources to maintain system reliability.

Results

During the full operational test of the system, the process from initiation of the trigger by the distribution operator to transfer of facility load to the generators occurred in just over three minutes. This was well under the 10-minute target process response time, which is one of the requirements for participation in some market-based programs.

Note that the actual equipment startup and transfer of facility load can take place in approximately thirty seconds. The system testing revealed a larger share of the elapsed time was consumed by facility managers who log onto the system and acknowledge the curtailment request via a Blackberry as pictured (lower left). In order to minimize this delay, the acknowledgement message was sent to several facility managers and any one of those facility managers was capable of acknowledging the message. Once the technology has matured, this acknowledgement step will also be automated to minimize response time.

Utility Benefits

The successful system test provided valuable feedback on performance and was in line with the project goals. Distribution operators were able to gain near-real-time visibility into the customer resources, remotely activate the customer resources, and target a select number of resources to address local issues. The system will be a valuable tool for the distribution operator to utilize during contingencies.

Customer Benefits

Previously, the market-based programs administered were limited to power generating facilities due to the minimum capacity and response times required. The new system will aggregate distributed resources to meet the minimum requirements and, via the system automation, provide the reliability of a quick response. This enables additional program participation with the utility and allows customers to realize new revenue streams.

For the full case study, search www.epri.com for product number 1026437.

Consolidated Edison

Using distributed energy resources to achieve greater reliability at the Jamaica substation may be possible for about 2/3 the cost of adding additional capacity.

Con Edison Case Study on Assessment of Achieving Increased Reliability with Distributed Energy Resources

Con Edison undertook an investigation of whether distributed energy resources, including distributed generation, storage and demand response load reductions, could help achieve greater reliability for a network served by a specific substation in New York City. The project was a first-level screening to determine the feasibility, costs, and benefits of using distributed energy resources as an alternative to conventional transmission and distribution upgrades over a 10-year period.

The Jamaica network, which feeds a portion of the Queens area, is the network targeted in the study. This part of the system is under consideration for reliability improvements because of the perceived high costs associated with extended outages in the area. The Jamaica station is designed for an N-1 (N minus one) contingency. N-1 means that in the event of the loss of the single largest element, the substation would still be able to handle the load.

Upgrading the Jamaica substation from N-1 to N-2 would enable the substation to carry the load with the loss of two transformers.

The Simulations

The assessment of whether achieving N-2 reliability could be achieved with distributed resources was conducted using protocols and analysis tools developed by EPRI. The operation of an N-2 system was simulated using EPRI's Demand Response Assessment Tool, a model developed to support evaluation of demand response and distributed generation for enhancing transmission and distribution system operation.

The specific characteristics of the Jamaica system, modeled over 336 consecutive hours, were incorporated into the model. Assumptions included that it would take Con Edison two weeks to get a second failed transformer repaired and back in service. The Jamaica hourly loads for a corresponding summer peak load period were compared with the carrying capacity of the three remaining transformers to establish hourly megawatt shortfalls in meeting the N-2 criteria.

To sustain reliability, the portfolio of distributed resources was constructed starting with the least expensive to build and operate, and adding more resources until the N-2 criteria was met in every hour of the two-week period. The use of each constituent resource was summarized and the costs (net present value of the ten-year study period) estimated.

Three scenarios were simulated, featuring distributed technologies suitable for deployment in an urban setting, and included a wide range of resources as well as conservation voltage reduction (CVR):

Scenario 1: CVR, demand response load reductions, and energy storage (no distributed generation)

Scenario 2: CVR, demand response load reductions, energy storage, small- scale photovoltaic (PV) systems, and other distributed generation. This included PV battery charging.

Scenario 3: All of the items in Scenario 2 plus the addition of smart-grid enabled demand response load reductions, deployment of advanced meters, home area networks, smart appliances, and other technologies.

The scenarios integrated and aggregated the various distributed energy resources under a common control structure so they could be utilized in the same manner as conventional generation. An algorithm that accounted for the complementary nature of multiple technologies was applied in the assessment. Demand response load reduction data was calculated based on the experience of demand response programs at Con Edison and elsewhere.

Results and Lesson Learned

- There is potential to achieve improved reliability in the Jamaica area, at least in the short term, at a lower cost by deploying distributed energy resources and demand response load reduction. It may be possible to achieve N-2 reliability at the Jamaica station for about 2/3 the cost of adding additional capacity.
- Achieving N-2 reliability is very expensive, especially for the last increment. However, a reliability standard of N-1.75 might be achievable using distributed energy resources for a relatively modest cost.
- The application of distributed energy resources to reach N-2 reliability is likely to be a transitional solution. If growth in the area served by the Jamaica substation continues, conventional equipment such as an additional transformer may be needed to meet base load and reliability requirements beyond 2019. But, delaying investment for up to 10 years by deploying distributed energy resources could result in substantial savings for Con Edison and its customers.
- The analysis was insightful as a first step. A more in-depth study is warranted with a more detailed analysis of the cost and benefits of distributed resource technologies based on results of demonstration projects at near-economic scale and scope.

For the full case study, search www.epri.com for product number 1026438.

Consolidated Edison

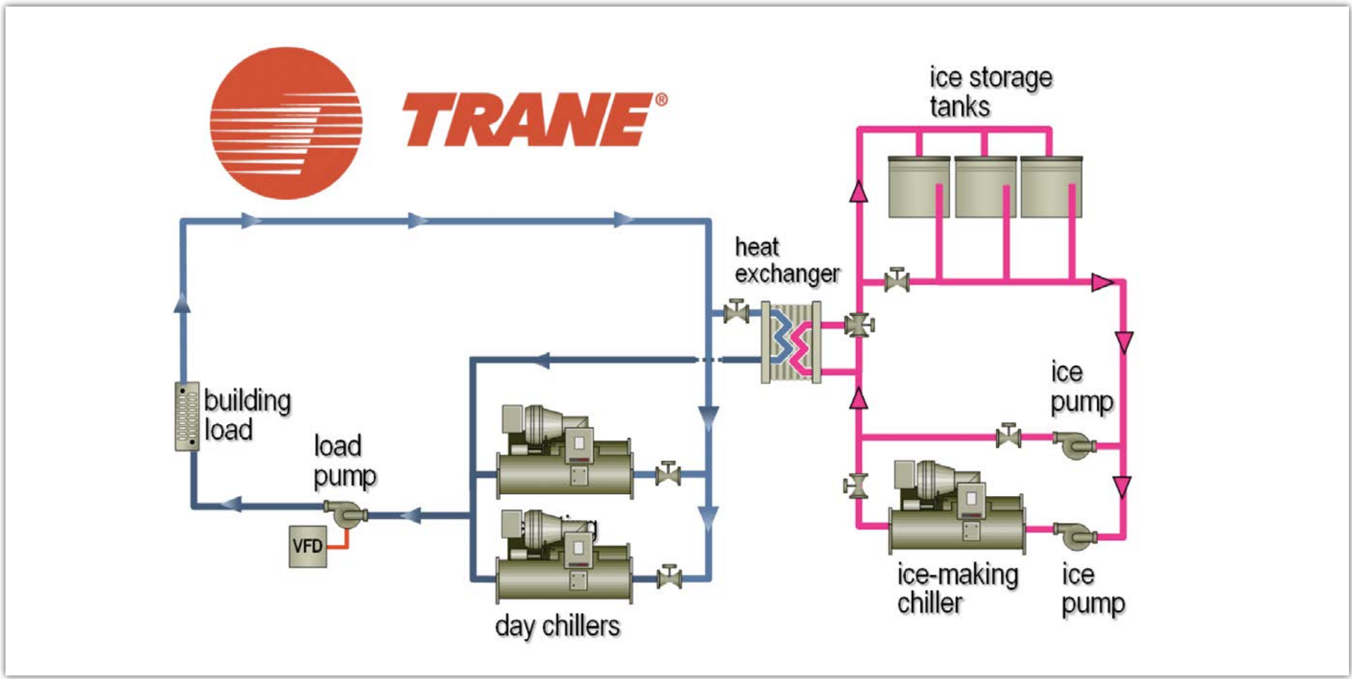


Figure 1 – Thermal storage plant

The ability to supply ancillary services can enhance the value of thermal storage plants, and aggregation opens up markets to demand response by enabling smaller facilities (<1 MW) to participate

Demand-Side Uses of a Thermal Storage Plant

This study determined the feasibility of using smart grid technologies to enhance the economic value of cogeneration and/or energy storage systems by simultaneously maximizing power system demand reduction, supplying ancillary services and increasing energy efficiency.

The initial phase of the evaluation involved comparing alternative cogeneration technologies—those utilizing internal combustion engines to supply cogeneration versus fuel cells—to select technology with the best economic and environmental performance. The analysis showed that the economics of the fuel cell, based upon the PureComfort Model 400M system, were superior. However, to meet a 3-year payback target established by Verizon, a partner of Con Edison in its smart grid demonstration, and the host of the to-be-selected technology, an analysis of energy storage options was conducted. For the behind-the-meter application, several electrochemical and thermal technologies were assessed. A thermal storage plant designed by Trane was able to meet an approximate three-year payback. This payback was based on covering some of the capital costs with a grant from the U.S. Department of Energy and a NYSERDA energy storage subsidy.

As a result of the analysis, the Trane thermal storage plant, with a storage capacity of 10,000 cooling ton-hours and 63 Cormac storage tanks, was installed at the Verizon headquarters in New York City. The Verizon facility is a 1-million square-foot building with a peak demand of 4.8 MW. The installation was commissioned in November 2013. A diagram of the thermal storage plant is shown in Figure 1.

To integrate the thermal storage plant into the "smart grid," the installation included an incremental building management system (IBMS), which is composed of digital controls to remotely control demand of specific elements of the air conditioning system such as air handling units, chillers, cooling towers, thermal storage tanks and chilled water pumps. The IBMS provides the precision control needed to follow the NYISO ancillary service market rules. (See Figure 2.)

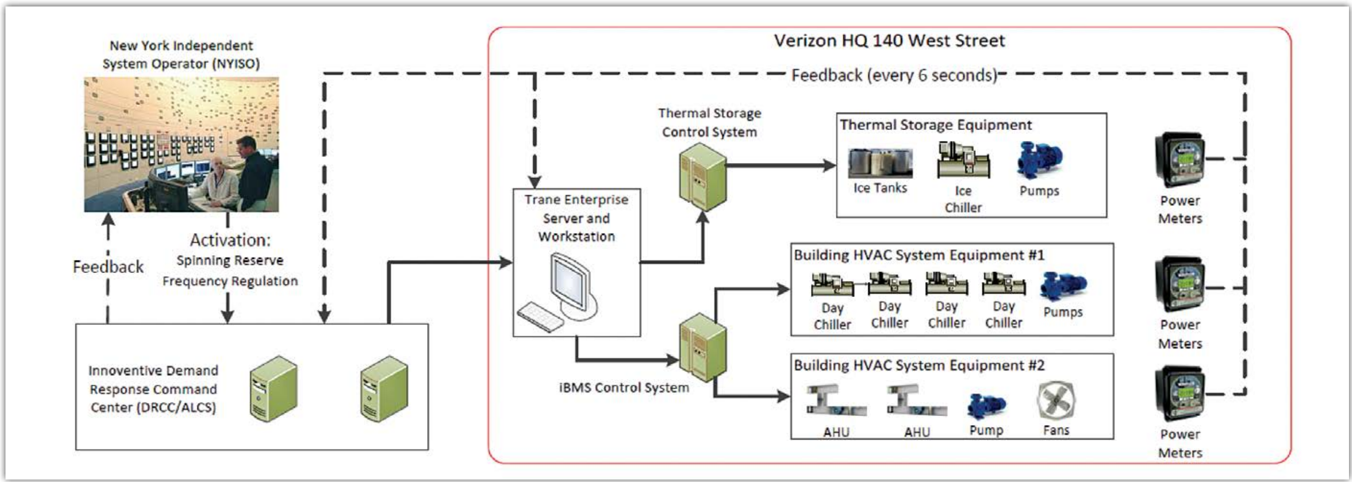


Figure 2 – Integration of building controls with NYISO for ancillary services supply

A Demand Response Command Center (DRCC), which is managed by Innoventive Power, has two-way communication with the NYISO, and directs building controls to vary demand as needed in response to regulation or reserve signals from the NYISO to either increase or decrease demand.

To optimize the use of the stored energy, an algorithm was designed to melt the ice for circulating chilled water as the cooling demand varied during the 14-hour period. During most summer-period days, the cooling requirement is greater than the capacity of the TSP, so incremental cooling is provided by a conventional chiller.

Results

The test program has provided valuable results as of mid-2014, including a model that calculates energy costs and identifies opportunities to optimize performance. Model calculations and testing of the system to date indicate the thermal storage system can meet a 3.3 year payback target and meet performance and reliability goals.

The 10,000 cooling ton-hours of storage represent a potential to shave about 1,100 kW of peak demand when the demand of the building peaks. As the cooling demand reduces (i.e. lower outdoor air temperatures), the cooling demand becomes flatter, so somewhat less demand reduction is achieved. On average, the project has determined that the summer monthly peak can be reduced by 1,000 kW. The total benefit of using the 10,000 cooling ton ice system has been estimated at $695,000 per year. This is from a combination of reduced energy consumption, peak shaving, and supplying ancillary services.

Lessons Learned

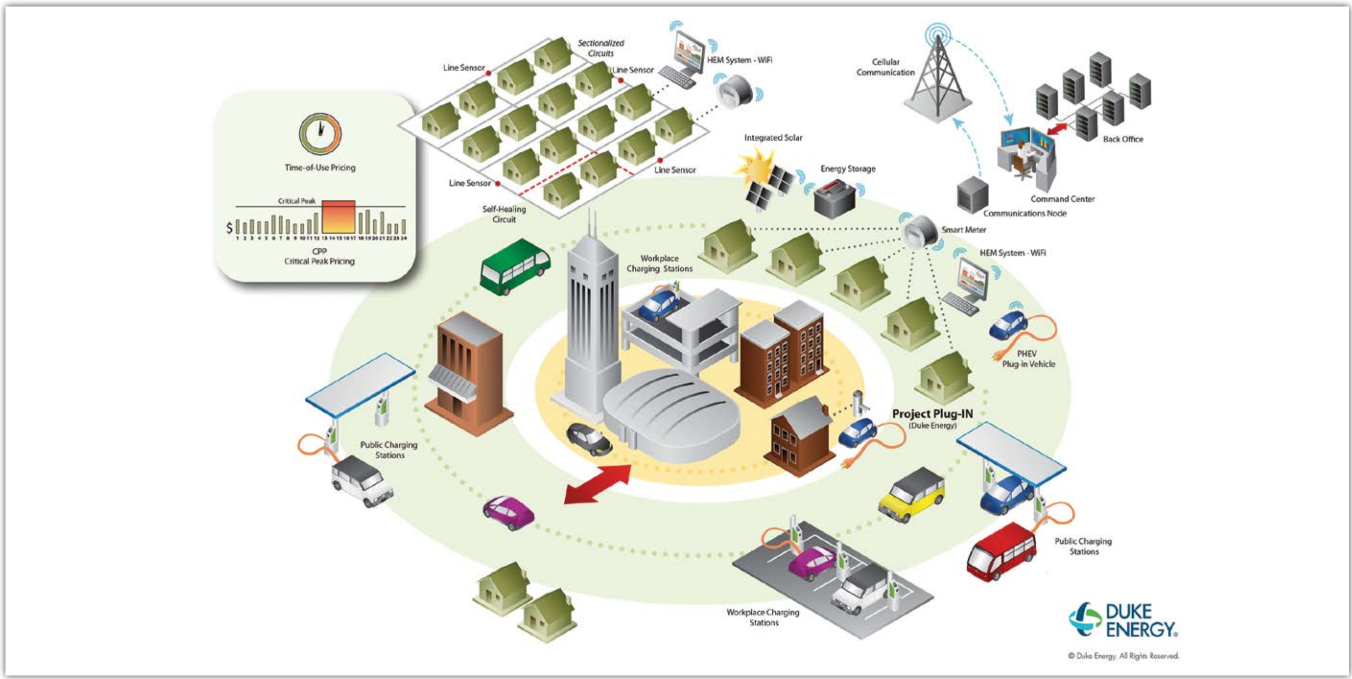
- The ability to supply ancillary services as well as reduce and shift energy use can enhance the value of a thermal storage plant.
- Aggregation is opening up the ancillary services markets to demand response by enabling smaller facilities, which cannot provide the minimum of 1 MW, to participate in NYISO markets.
- Changes in technology can occur during the course of many smart grid related projects. In this case, advances in Cloud computing enabled the Demand Response Control Center to be hosted in the Cloud, lowering costs and enhancing the value of ancillary services.
- The best way to divide the building load in this case is to supply a constant base from the day chiller and the remainder from the stored energy.
- Consider disaster preparedness when designing building systems. Experience from Superstorm Sandy led to redesign of the ice storage installation in order to protect against damage from future storms. Equipment was moved to the first floor from below ground.

Recommendation and Next Steps

Data developed from this project indicates a similar test of a fuel cell would be beneficial as a fuel cell is also capable of enhancing economic value to a facility by supplying ancillary services. Such equipment may serve as a "virtual generator," which can respond to ISO triggers within a given time frame and for a sustained period of time.

For the full case study, search www.epri.com for product number 3002003870.

Duke Energy



The operational success of either a centralized or decentralized approach to self-healing networks is highly dependent on the reliability of the communications network.

The Duke Energy Smart Grid Demonstration project designated The Envision Energy area in Charlotte, North Carolina as the test bed for grid modernization projects. The primary objectives were to improve the operational efficiency and reliability of the distribution system, facilitate the expansion of energy efficiency and customer demand response, prepare for the integration of higher levels of renewable generation, and provide a communications and distributed intelligence platform for new products and services.

Approaches to Self-Healing Networks

Duke Energy has deployed self-healing networks as part of its smart grid efforts. Two are in the Envision Energy Area, one using a decentralized control approach and the other employing centralized control. Other centralized self-healing networks, using a different system than the Envision Energy Area centralized scheme, have also been deployed. These networks are part of Duke Energy's on-going field demonstration and testing of the auto-restoration schemes in approximately 100 deployed self-healing networks across Duke Energy service regions as of mid-2014.

The primary objectives of the Envision Energy self-healing networks was to demonstrate the capabilities of two self-healing networks systems that were new to the Duke Energy system and to provide a test bed for evaluating different wireless communication technologies.

The traditional self-healing network involves two circuits, each with a mid-circuit recloser and a recloser at the normal open point between the circuits. This is typically the setup for the decentralized schemes. In the centralized approach, the number of line devices in the scheme can be increased to further segment the circuits into self-healing zones. An example of this is shown in Figure 1, in which there are 10 devices in the auto-restoration scheme, including the two circuit breakers.

Approach

Within the Envision Energy area, the decentralized network uses the S&C IntelliTeam® Smart Grid (SG) Restoration System to reconfigure the network when a fault occurs within the network. Each of the three IntelliRupters® in the decentralized scheme is programmed to know its normal role in the network, its DNP3 address, and other local settings, such as its maximum current carrying capacity and normal source. Each of the three IntelliRupters monitors its real-time voltage and currents via embedded sensors. The telemetry data is shared by direct communications between the three IntelliRupters. When a fault occurs within the network, the IntelliTeam SG Restoration System determines the location of the fault and opens the appropriate IntelliRupters to isolate the fault.

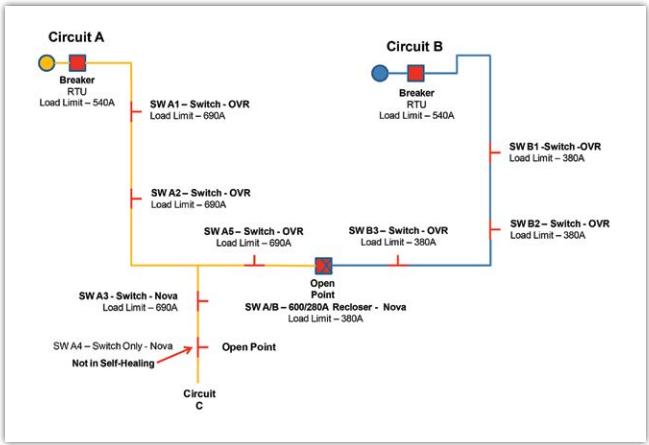


Figure 1 – Single-line diagram of a centralized self-healing network

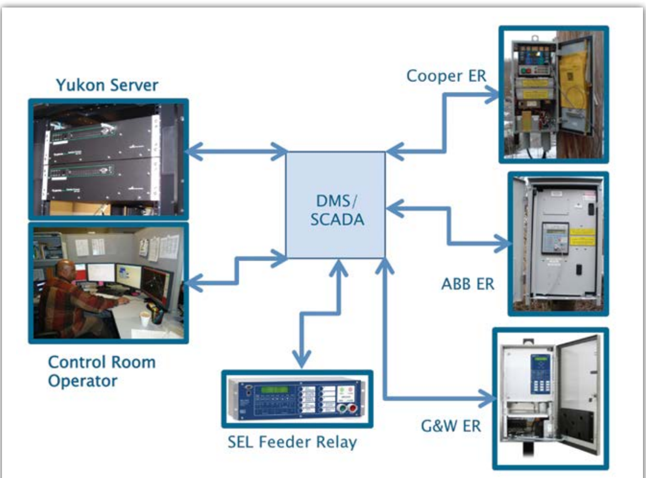


Figure 2 – Centralized approach to a self-healing network

The centralized approach uses the NovaTech Orion Substation Automation Platform with unique distribution automation (DA) logic software to perform the self-healing functions for each network. The software allows the DA controller to act as a master controller of the utility defined network. The DA controller polls each intelligent electronic device (IED) in the network via SCADA to determine the state of the network devices. When a fault occurs, the DA controller analyzes the IED information to determine where the fault is located. Based on the utility-defined system reconfiguration parameters, the DA controller initiates trip and close commands to automatically restore service to as much of the network as possible.

Outside of the Envision Energy area, the Cooper Yukon system, a centralized platform for self-healing networks, has been used for the majority of the self-healing networks in place today. As illustrated in Figure 2, The Yukon server monitors and controls all of the self-healing line and substation devices via its link with SCADA and the distribution management system (DMS). Since it is agnostic to the types of IED devices, standard recloser and electronic relays (ER) used by Duke Energy can be utilized together in the self-healing network. This is an advantage over many of the decentralized self-healing network systems since they either require the use of line devices and control and/or communications systems made by the same manufacturer or require an interface module to incorporate non-standard equipment.

Results

As of the end of 2013, the deployed self-healing networks had seen 91 successful operations. These operations prevented a sustained outage for approximately 124,000 customers. As a result, it is estimated that Duke Energy saved roughly 13 million customer interruption minutes via the automatic restoration schemes. Building on this achievement, Duke Energy plans to add 52 self-healing networks to its distribution system in 2014.

The evaluation of different communication technologies, such as LTE and WiFi, will continue to be evaluated into the future.

Lessons Learned & Key Recommendations

- The majority of failures associated with self-healing networks are due to communication issues. As a result, the utility must make repairing sustained communications failures a priority for field technicians.
- Due to the complexity of the schemes, the installation of and the settings for the devices must be performed correctly for the self-healing network to function properly. Source and load instrument transformers must be identified and wired correctly for accurate sensing. Thermal ratings of equipment and conductors of all circuits involved must be factored into the logic of the scheme.
- The IT and OT departments, as well as the field crews, should be actively involved in the early deployments of these systems. Their input in working through the challenges and issues with the pilot projects helps to build trust and support for continuing deployment of similar systems.

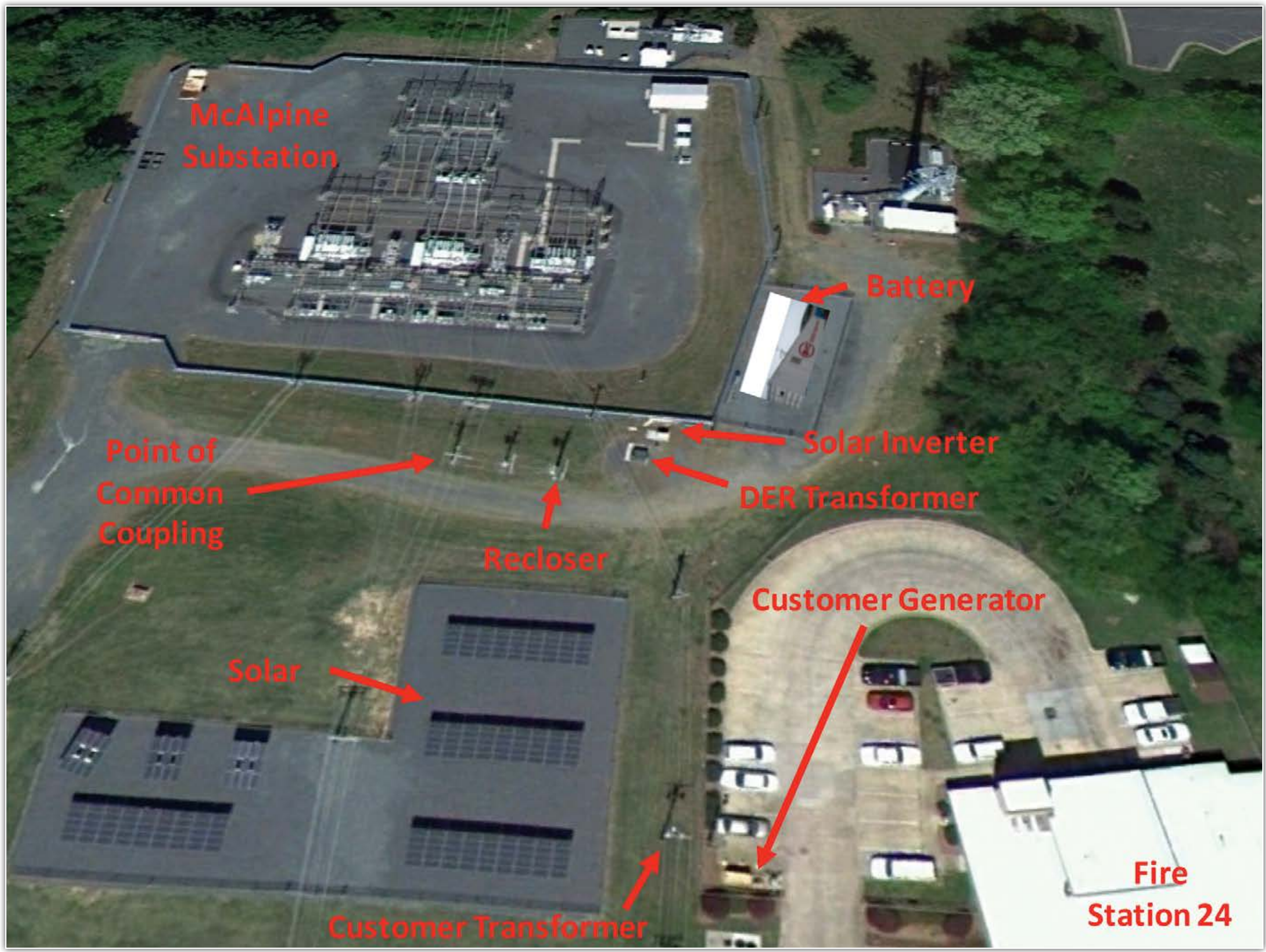
Next Steps

Duke Energy plans to do the following to enhance their self-healing networks:

- Continue communications research to further minimize communication failures, especially the brief communication dropouts.
- Test software for inclusion of larger grid-connected distributed energy resources into self-healing networks, and deploy a pilot system for field demonstration.
- Demonstrate the capabilities of the fault location, isolation, and system restoration (FLISR) application of their advanced distribution management system.

For the full case study, available by the end of 2014, search www.epri.com for product number 3002004619.

Duke Energy



A utility-scale microgrid can be created from disparate distributed energy resources and typical distribution line devices, relays, and controllers.

Utility-Scale, Single-Customer Microgrid at Duke Energy

The McAlpine microgrid demonstration project is a 24 kV utility-scale microgrid that serves a fire station located adjacent to the McAlpine distribution substation. The distributed energy resource (DER) components of the microgrid are a 50 kW solar array with a Satcon inverter and a 200 kVA, 500 kWh BYD lithium-iron-phosphate battery and inverter system. The other components, the reclosers, switch, transformers, and microgrid controllers, are off-the-shelf, standard-use equipment on the Duke Energy distribution system. See figure for a schematic of the system.

Project Objectives

The key objectives of this microgrid demonstration are:

- Provide a higher degree of reliability to the customer via an inverter-based microgrid.
- Demonstrate the ability to create a utility-owned microgrid from standard utility equipment.
- Test the ability of disparate equipment and DER to provide a seamless transition to and from connection with the grid.

Methodology

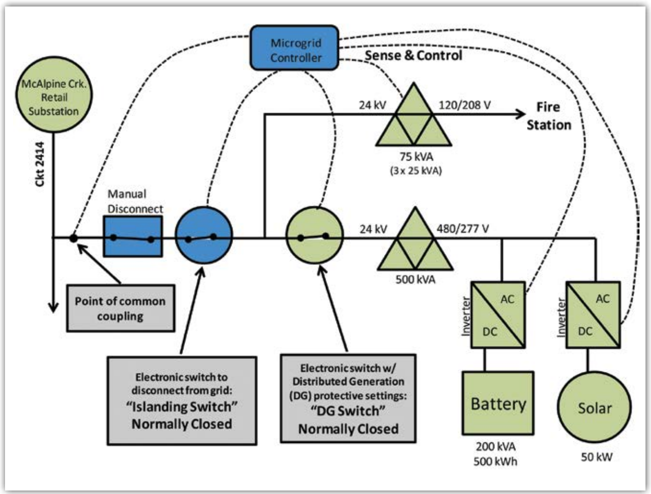
Since the microgrid energy resources (a photovoltaic [PV] array and battery) were previously used in other demonstration projects, they had to be modified to function as one power system when islanded. The battery inverter software was upgraded to include islanding capabilities in order to maintain the voltage and frequency of the microgrid when disconnected from the grid. As a result, the battery switches from a current source when connected to the grid, to a voltage source when disconnected.

Load bank and stand-alone system testing were performed on the battery and solar inverter systems to simulate the operating conditions the microgrid would be subjected to while in service. The following three tests were conducted to determine the behavior of the DER:

1. Island mode – The battery was tested to determine its ability to act as a voltage source when disconnected from the grid. The thresholds were 435 - 525 VL-L and 59.85 – 60.5 Hz.
2. Unplanned grid outage – The battery's ability to transition from current to voltage source within 100 msec. was examined to ensure that the system would operate in a closed transition mode to prevent a momentary loss of power when an outage occurs.
3. Island and UPS mode – Tests of the battery and solar components to remain synchronized during and after a transition from being grid connected were conducted.

Results

The tests demonstrated that the disparate systems can function as a utility-scale microgrid. The battery system displayed the capability to operate as an island with stable voltage and frequency with and without the PV array synchronized to the island. The only exception was that the PV inverter tripped off line at 520 VL-L, just shy of the upper voltage limit. The transition test of the battery proved to be successful also. The battery system transitioned from a current source connected to the grid to a disconnected voltage source in approximately 2 cycles (32 msec.) upon receiving loss of voltage signal. It formed a stable island within 6 cycles (less than 100 msec.). Throughout the transition, the PV array remained online.



Lessons Learned

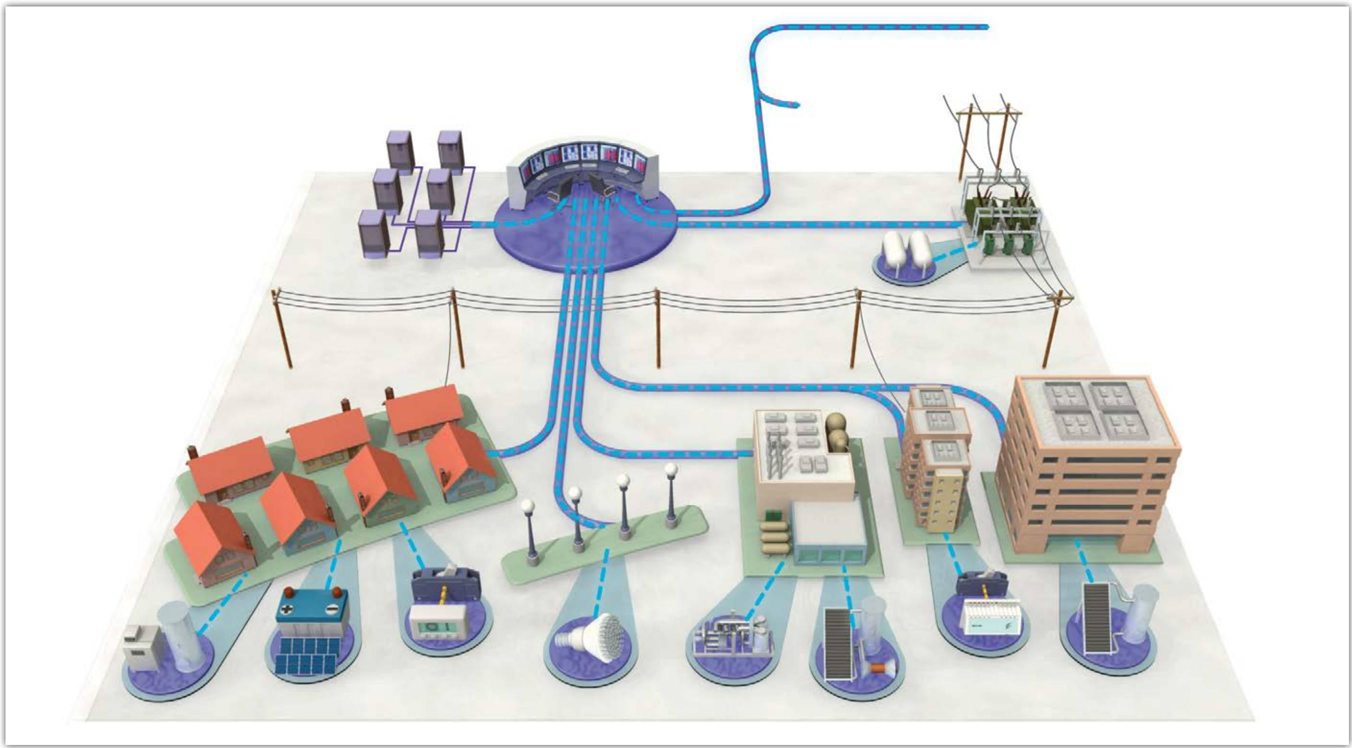
- A protection and controls study found that the low fault current availability when islanded required the main breaker at the fire station to be replaced with one of a suitable rating.
- Additional coordination between the islanding switch and the DG switch was required to permit successful transition to and from the grid.
- Standard inverter software has anti-islanding features built in. As a result, software modifications were required for islanding operation.
- The full capabilities of standard utility devices, relays, controllers, and reclosers may be unknown and must be explored in order to build a microgrid with standard components.

Next Steps

The next steps are to operate and test the systems with the customer connected to the microgrid. Future testing will include distributed energy resource management system (DERMS) integration. Wireless communications will be tested to determine wireless performance characteristics versus wired connections between the microgrid components. As the demonstration continues, Duke Energy plans to document all of the lessons learned in order to develop an operations standards document that will permit the company to more easily implement additional customer microgrids.

For the full case study, available at the end of 2014, search www.epri.com for product number 3002004618.

Electricité de France



Distributed energy resources can be aggregated in an optimized way in order to respond to load reduction requests during peak periods.

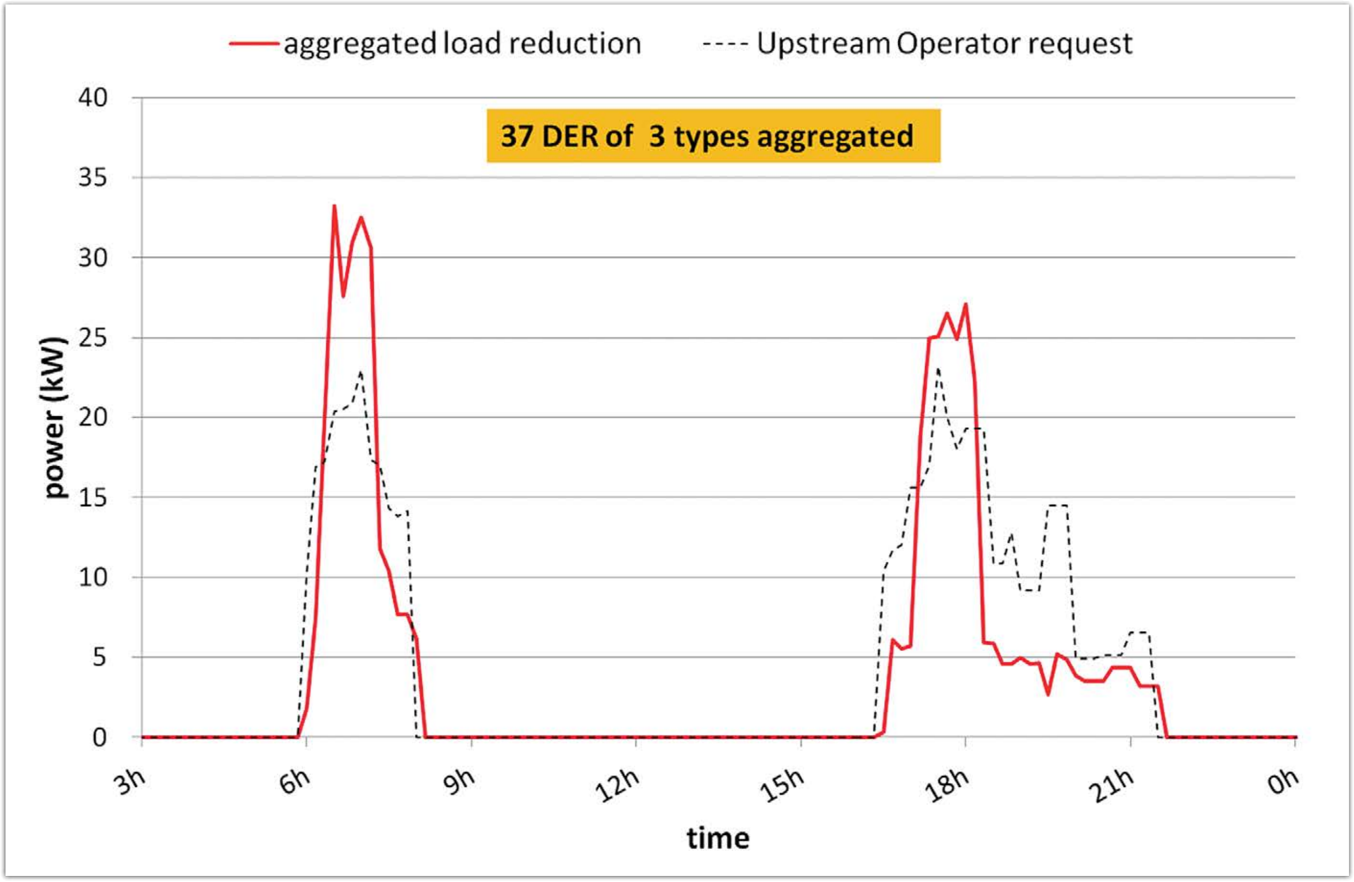
The Electricité de France (EDF) Smart Grid Demonstration features PREMIO (Production Répartie, Enr et MDE, Intégrées et Optimisées), an open architecture system designed to optimize the simultaneous control of distributed energy resources (DER), such as thermal storage and electric batteries, that can serve as a virtual power plant when aggregated.

The Response Precision of PREMIO Virtual Power Plant

The PREMIO project was designed for peak shaving in southeast France, where the power system faces increasing constraints. The project is exploring reducing loads in response to operator requests via:

- A central control unit and infrastructure located at customer facilities
- A communication and information system that enables operation, planning, and maintenance tasks

The control unit simulates an upstream operator by sending an offer for a variable length "critical period" as either a day-ahead request or an intraday request.



The Tests

The period of the study is the "cold" season of October 2011 through April 2012. Measuring response precision was a key goal of the tests, which were initiated every two days. A total of 231 load reductions of various amplitudes and durations were measured.

The control unit aggregated three different types of DER to achieve the load reductions:

- A "smart box" that controls electric space heaters and water heaters (10 included)
- A heat pump coupled to a hot water tank that delivers hot water to the heating circuit when the heat pump is turned off (6 included)
- Lead-acid batteries that inject power into the grid (21 included)

Control settings for each type of DER included the minimum delay between consecutive load shedding periods and the maximum duration allowed for a load shedding.

Results and Lessons Learned

The analysis of results included the following observations:

- The system responded very reliably and on time, resulting in a good load reduction profile although the precision of the response profile was irregular.
- The response velocity can reach 60 kW/hour.
- Load curve is sensitive to consumer behavior and outside temperature.
- Technical issues, such as communications losses, may impact availability of each DER.
- The smart boxes may shed only a part of the load due to optimized device control settings.
- Due to open-loop design, control requests cannot be modified once issued.
- Only four customer overrides of smart box control occurred.

For full case study, search www.epri.com for product number 3002002024.

Ergon

> *Financial incentives and an engagement effort that featured person-to-person and repeated communication with customers led to sufficient reduction in energy use and peak demand to defer the installation of an additional submarine 22 kV cable.*

The Ergon Energy Smart Grid Demonstration program, also known as the Energy Sense Communities program, consists of about 30 initiatives. The overall aim of these combined projects is to manage the electricity network more efficiently, deliver reliability service standards, and find suitable alternatives to meet rising demand. The program focuses on alternative energy solutions for residential and commercial sectors, as well as technologies that can help defer investment in network assets such as distribution substations. The program initiatives are divided into three areas of focus: 1) Smart Net (network), the electricity distribution grid, 2) Smart Res (residential), the residential community, and 3) Smart Biz (business), the commercial and industrial energy user.

Deferring Asset Investment with Distributed Energy Resources

As part of a jointly funded (government and Ergon Energy) smart grid project, Ergon Energy conducted a Solar City project on Magnetic Island, which is just off the coast of the state of Queensland in Australia, very near the mainland city of Townsville. Ergon Energy conducted the Solar City project to offset energy growth and shift demand.

Magnetic Island has roughly 2,100 year-round, permanent residents. The island is also home to the Magnetic Island National Park which makes up 63% of the land area of the island. The focus of the program was the residential sector, as the island has a relatively small commercial sector.

The Magnetic Island Solar City project started in 2007 after a successful bid by an Ergon Energy-led consortium. The Consortium included state and local government agencies, a university, equipment suppliers, and residential and commercial property developers.

Project Objectives

The main objective of the Solar City project has been to achieve sufficient reductions in energy use and peak demand on Magnetic Island to defer investment in a third submarine cable delivering electricity to the island.

In its overall demand management program, Ergon Energy has a goal to reach a target of a total of 122 MVA offset by demand management by 2015, and this was achieved ahead of time in 2014.

Methodology

Several "treatments" to reduce electricity demand and peak were offered as part of the project:

- An energy audit that included a light bulb/shower head retrofit.
- The installation of smart meters and an in-home display.
- Installation of photovoltaic solar panels (Figure 1).
- Financial incentives to purchase more energy efficient appliances and equipment and dispose of old refrigerators.
- Promotion of an "economy" off-peak tariff in combination with direct load control of selected equipment during peak hours. Appliances targeted for the rate, which entailed hardwiring, included water heaters and pool pumps. Besides savings from the off-peak rate, a financial incentive ($100 in mid-2014) was offered to customers to sign up for the rate and direct load control.

Marketing of the treatments was designed to maximize customer acceptance and participation, relying on face-to-face customer engagement, social marketing, and thematic messaging. This approach is called the Energy Behavior Change Model (EBCM).

To select marketing messages and design incentives for customer participation in the program, Ergon Energy conducted surveys and focus groups. One of the principles of the marketing framework is basing messages on what customers (rather than utilities) consider barriers and benefits.

Results

The combined savings from these programs allowed Ergon Energy to defer the installation of an additional submarine 22 kV cable (the island is currently served by two such cables) for at least eight years (as of 2007, although the need is reviewed annually). The deferred expense is roughly $17 million (calculated in 2007—in today's terms it would be closer to $21 million).

More than 47 MVA in targeted peak demand reductions was achieved for the 2012/13 period in the overall Ergon Energy demand management program, with Solar City contributing about 5 MVA.

Figure 1 – Example of rooftop solar installation

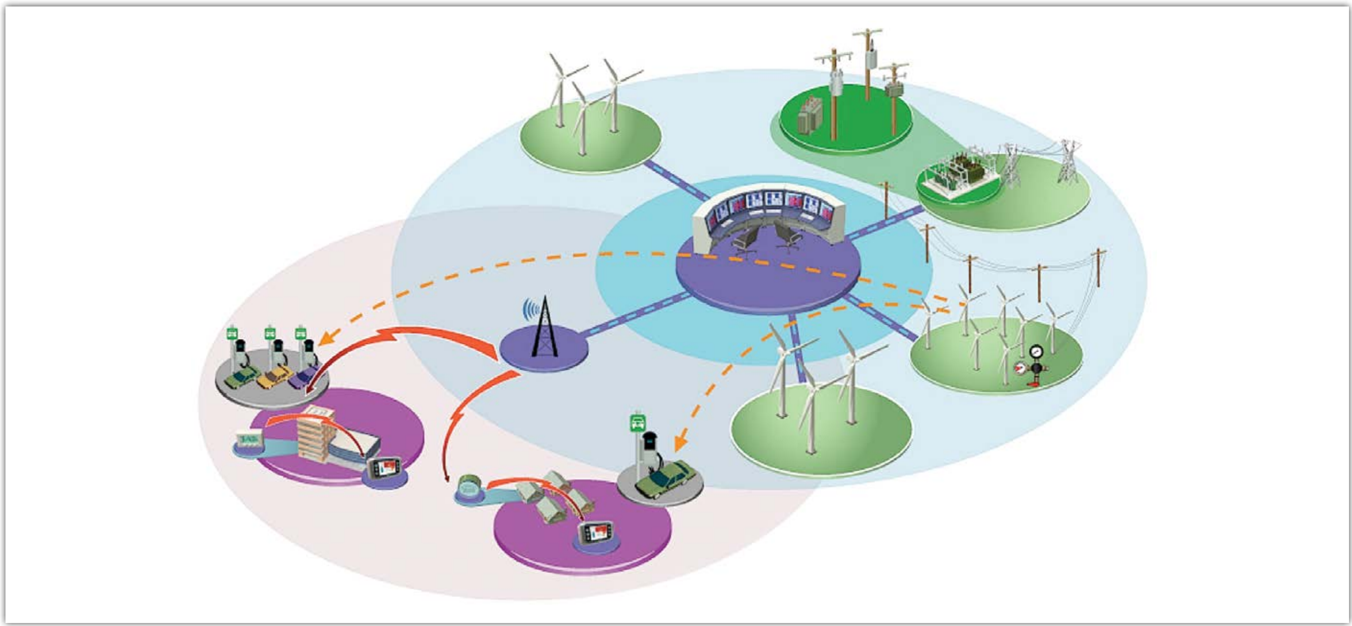
The Solar City project has led to a reduction in peak demand by 16 percent (to equivalent 2005 levels). In addition, greenhouse gas emissions were reduced by more than 54,000 tons as of June 2012. Ergon Energy plans to use the lessons learned from the community engagement effort on Magnetic Island as it looks to more broadly apply these demand management technologies to the rest of its distribution grid.

Lessons Learned

- Survey findings indicated that customers who installed a a very high efficiency (5-star rated) pool pump or changed their pool pump to an off-peak tariff did so because of Ergon Energy's cash back offers (54% of households took advantage of the cash back program).
- The peak demand reduction efforts suggest that "chore" related activities might be flexible (washing can in some cases be rescheduled) but leisure activities may be less likely to change. Part of this may be due to customers having a fixed period for leisure activities relative to when they sleep or have to be at work.
- The peak demand reduction portion of the project suggests customers could be separated into two segments. One group of customers may be intrinsically motivated and might make changes simply by being armed with information whereas others are more extrinsically motivated and may need some incentive in addition to information to make changes.
- Based on results of energy assessment, Ergon Energy believes direct customer engagement is one of the keys to success. Customers are educated and immediate changes (light bulb and shower head replacement when conducting an energy audit) can be made.
- When there is no financial benefit, some customers will not participate. For example, some customers were not inclined to have PV installations where the utility leased the roof (due to potential structural damage). Outside of the lease there was limited benefit to the customer
- Initially cash back rewards were delivered as a separate check, but given a choice, most customers said in the project exit survey that they preferred that the monies simply be applied to their energy bill.

For the full case study, search www.epri.com for product number 3002004413.

ESB Networks



> *A "self-healing" circuit has operated successfully in over 12 separate incidents, with faulted sections isolated and supply recovered to remaining customers within seconds.*

ESB Networks Smart Grid Demonstration Project consists of four separate but related work streams selected to advance development of ESB's model of a future, integrated network. The smart grid demonstration includes trials of new and innovative methods for integrating renewable generation resources and electric vehicles, studies of customer behavior, and optimization of existing distribution electricity networks.

Smart Green Circuits at ESB Networks

A smart grid is not just about enabling customer responsiveness or a high penetration of renewables, but also about creating "smart green circuits" that enable operational efficiency, monitoring of line conditions, loss reduction, and protection.

Smart green circuits are an important part of the demonstration undertaken in Ireland, as the size and scale of the country's electricity distribution system presents unique challenges in terms of maintaining continuity of supply to customers within a high standard, and ensuring that network losses are minimized.

ESB conducted tests of smart green technologies on four distribution circuits. Three are rural (Kerry, Galway, Dungloe), and one is urban, near Dublin (Sallynoggin).

The Technologies and Tests

A number of systems and applications were evaluated to help create efficient and "self healing" circuits, including:

- A smart fault passage indicator system was added to the Kerry circuit. This system locates and analyzes faults and communicates information to network operators via GPRS (general packet radio service) communications to facilitate quick response. Fault notification is sent to the iPhones of network technicians.
- An arc suppression coil protection system was installed on ESB's 20kV circuits. This protection system is designed to carry earth faults safely while continuing to supply customers.

Arc suppression system at Gurranbane Substation

- A cost-benefit analysis of replacing conventional transformers with low-loss transformers was conducted. This was done because there are a large number of lightly loaded transformers in operation in Ireland, and core losses contribute significantly to overall network losses. Costs considered in the analyses included cost of ownership, capital costs, and costs of winding and core losses.
- Circuits were converted from a 10kV to a 20kV operation voltage. For example, the long Galway network, which serves 2,200 customers, was operating at voltages outside of the standard so conversion to 20kV was done to improve ESB's ability to maintain operation within prescribed voltage levels.
- Simulations and field tests of conservation voltage reduction (CVR) were performed. CVR was done on two rural circuits, as well as the urban Sallynoggin circuit.

Results and Lessons Learned

- The self-healing circuit has operated successfully on over 12 separate incidents of faults. On all occasions, a faulted section of network was isolated and supply was recovered for remaining customers within seconds. The success of the trial has led to plans to change the worst performing network sections in the country into self-healing circuits.
- The performance of the arc suppression coil protection system, complemented by a range of earth fault management facilities in operation on ESB's 20kV network, has been proven successful. ESB has achieved cost reductions, fault-finding time has been reduced by 84%, and measured continuity of performance improved by 100%.
- The case to continue doubling the operation voltage of ESB's medium voltage network is overwhelming. Conversion of networks from 10kV to 20kV resulted in a 75% reduction in network losses, an improvement in voltage drop by a factor of four, and an increase in network capacity of more than 100%.
- Conservation voltage reduction resulted in significant reductions in energy demand, with measured CVR factors ranging from 0.83 to 1.74.
- Cost-benefit analysis shows that a strong economic case can be made for amorphous core transformers rather than conventional silicon steel units in cases where a transformer needs to be replaced for reasons other than just reducing losses.

Next Steps

Based on marked improvements, the self-healing configurations in this case study and other forms will be extended to all overhead networks through 2025.

For the full case study, search www.epri.com for product number 1026440.

ESB Networks

The deployment of TOU rates and energy information services were found to reduce overall electricity usage by 2.5% and peak usage by 8.8%

Smart-Meter Customer Behavior Trial

ESB Networks conducted a customer behavior trial to gauge the potential for smart-meter enabled treatments, including time-of-use (TOU) prices and energy information services, to change customer energy consumption and peak demand usage.

The experiment was designed to ensure a robust, representative sample of the population, with 3,800 residential customers provided some combination of treatments and more than 1,100 customers monitored as a control group. All participants had smart meters.

For a six-month period prior to the beginning of the trial, the electricity usage profiles of participants were recorded to provide baseline data for the analysis of response to the tested measures.

Among residential customers, four different TOU rates were tested during a one-year trial, along with several different energy-use information services: monthly or bi-monthly bills with a detailed energy usage statement, and an electricity monitor (in-home display). Also offered was a load reduction incentive, which was a financial reward to customers who reduced their electricity usage by a certain percentage target when compared to the same period in the previous year. Pre and post trial surveys were also conducted to help provide insight on perceptions of customers and their motivations for behavior.

Small to medium businesses were also part of the experiment, with 650 business customers taking part in the trial. Two different TOU tariffs were tested among this group, along with an electricity monitor and a web account targeted specifically to businesses.

Delivery of these services and treatments relied on an advanced metering infrastructure featuring three different communications technologies: power line carrier (PLC), a 2.4GHz wireless mesh network, and point-to-point wireless (general packet radio service, or GPRS).

Results and Lessons Learned

In the residential sector, findings included:					
Usage	All tariffs and treatments (% reductions)	Bi-monthly bill and eergy usage statement (%)	Monthly bill and energy usage statement (%)	Bi-monthly bill, energy usage statement and monitor (%)	Bi-monthly bill, energy usage statement and financial incentive (%)
Overall	-2.5	-1.1	-2.7	-3.2	-2.9
Peak	-8.8	-6.9	-8.4	-11.3	-8.3

In the residential sector, findings included:

- As shown in the table, the TOU rates, energy information services, and financial incentives were found to reduce overall electricity usage by 2.5% and peak usage by 8.8% for the one-year period of the trial. Results are statistically significant at the 90% confidence level.
- The treatment that had the greatest effect on reducing peak usage, with a peak shift of 11.3%, was the combination of in-home display with the bi-monthly bill that features a detailed energy statement.
- No single type of TOU tariff offered in combination with information services stood out as being more effective than another.
- There is no evidence that there is a threshold point at which the price of electricity will significantly change usage. The demand for peak usage is highly inelastic to price.
- Ninety-one percent of survey respondents deemed that the in-home display was a support in achieving peak reduction and 87% considered it an important tool for shifting to night rates.

In the small-to-medium businesses sector, findings included:

- On average, no statistically significant reductions in overall electricity use or peak demand were exhibited by business customers.
- No specific tariff, information service, or combination of tariff and information service reduced overall usage or peak usage by a statistically significant amount.
- Only 15% of business customers reported logging onto the web account for energy use information.
- Among participants who did reduce usage or cut peak, 93% reported that the electricity monitor was an effective information resource and 85% who reduced peak demand said it was an important tool.

Communications technology findings:

- The power line carrier (PLC) communications system has major issues to overcome to deliver reliable daily profile data from every meter. Problems are also experienced with performance of on-demand tasks.
- A point-to-point wireless communication system generally worked well, but its long-term availability in a large number of meters is a concern. This technology seems most appropriate if there is a required roll-out of a limited number of meters in the near- to mid-term.
- The 2.4 GHz mesh network was a good fit in urban environments where meters are relatively close together. However, performance in rural areas, where wireless is most needed, was disappointing. Scaling of the system to large numbers may also be an issue.

Results of the customer behavior trial generally indicate that treatments designed to encourage changes in customer energy usage can assist customers in being more efficient in their use of electricity.

For the full case study, search www.epri.com for product number 1026441.

ESB Networks

The reactive power capabilities of modern wind turbines can be used for a range of objectives, such as loss reduction, local voltage control and reactive power export.

Distribution Volt-Var Control Integrated with Wind Turbine Inverter Control

Ireland will have the highest penetration of wind power in Europe by 2020, and as deployment of wind generators increases, a range of technological challenges must be addressed, including meeting frequency, voltage, and reactive power requirements.

This ESB project assessed multiple technologies including wind farm control technologies and their integration with existing SCADA communications systems. The main focus was how the decoupled reactive power capability of modern, doubly fed induction generator wind farms can be used to actively control the terminal voltage at the point of common coupling.

Emphasis was on the extent to which the reactive power capability of wind generators can be deployed to deliver benefits at the distribution level, ranging from reduced losses to increased hosting capacity. Work was also done on the interaction between the distribution and transmission systems to assess the potential for mutually beneficial schemes for reactive power control.

The Tests

A section of the distribution network that connects two wind farms—Knockawarriga and Tournafulla—and which is free of load customers, was selected to demonstrate technology to manage voltage. The research team simulated a number of voltage control schemes utilizing both the wind farm capability as well as the functionality offered by the on-load tap changer at the transmission-system-interface transformer.

Based on simulations, five different modes of operation for the network section were developed, taking into account both distribution system voltage performance and the reactive power requirements of the transmission system. Five different modes of operation were put in effect over a period of months to test technology, as shown in the table.

Stage	Dates 2011	Knockawarriga Windfarm	Tournafulla 2 Windfarm	Trien Substation OLTC
0	7 Jan 2011– 7 Feb	PF 0.95 importing	PF 0.95 importing	Fixed tap
1	7 Feb – 3 March	PF 0.95 importing	PF 0.95 importing	Auto tap
2	12 April – 13 May	PF 0.95 importing	Constant-V 42.2 kV, 4% droop	Auto tap
3	17 May – 24 June	Constant-V 41.7 kV, 1% droop	PF 0.95 importing	Auto tap
4	30 June – 9 Jan 2012	Constant-V 41.7kV, 2% droop	Constant-V 41.7kV, 2% droop	Auto tap
5	9 Jan - ongoing	Constant-V 41.7kV, 2% droop	Constant-V 41.7kV, 2% droop	Fixed tap

PF = power factor OLTC = on-load tap changer

Results and Lessons Learned

Among the conclusions of the study is that the constant voltage mode of operation:

- Can deliver a constant voltage through variation of var (volt amperes reactive) output, independent of megawatt (MW) generation.
- Can increase network hosting capacity.
- Can reduce network losses.
- Can reduce var absorption by embedded generators.
- Can reduce operational challenges posed by renewable generation.
- Cannot do all the above simultaneously to the full extent, so tradeoffs are required.

ESB found a number of factors that affect controller function:

- Network parameters and set points have a significant influence on the operation of the controller.
- The use of the constant voltage operation mode may not be part of the SCADA configuration and therefore re-configuration may be required.
- Different controllers are designed to offer different reactive control capabilities and beyond that the tuning of the controller may need increased oversight at the commissioning stage if general implementation of this control functionality is to be relied upon.

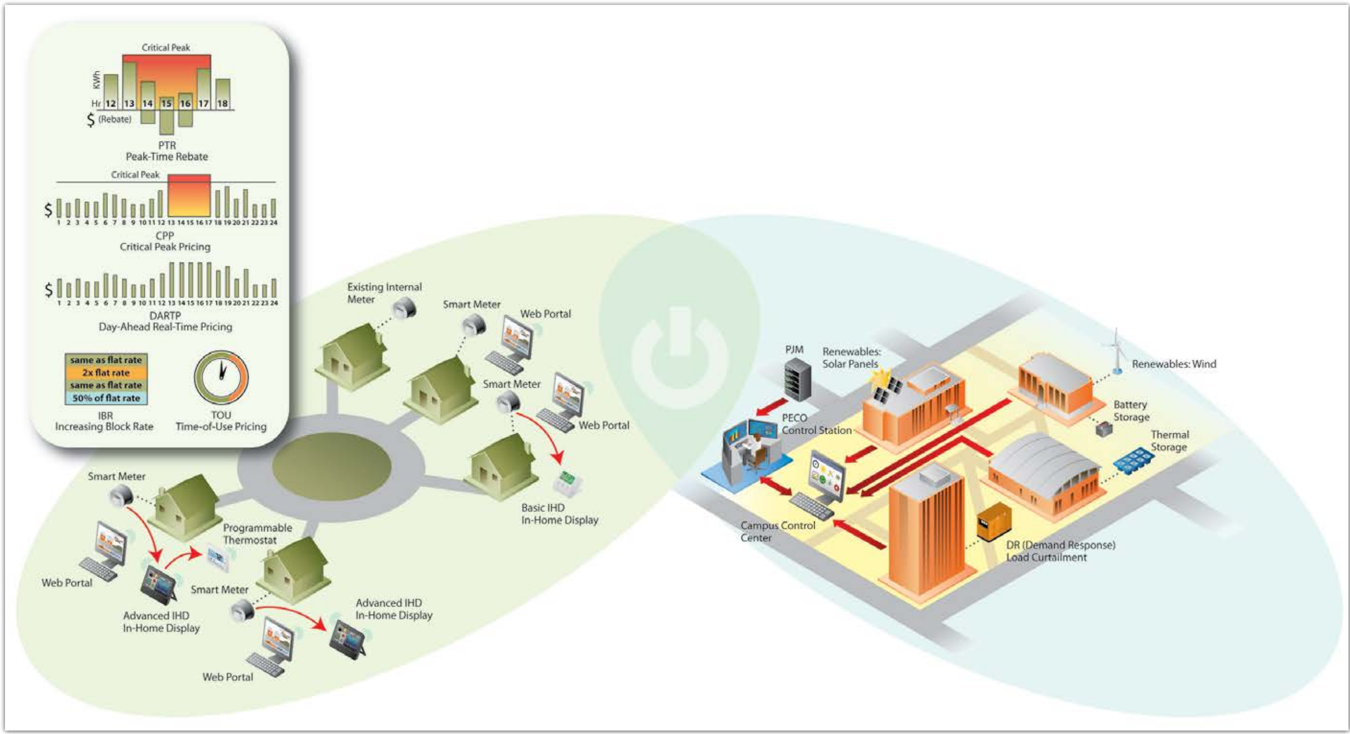
Overall, modern wind turbines can be used for a range of objectives, such as loss reduction, local voltage control and reactive power export; however, these objectives may be conflicting, dependent on factors noted including wind power output, network impedance and the state of the transmission system. Some key findings from the tests:

- Turbine technology and wind conditions affect ability to provide reactive power support.
- Tuning of parameters and commissioning of the wind farm controller has a large bearing on controller performance and network impact.
- Turbine technology and network impedance are key variables.

One clear outcome of the trial is that there is no single solution for enabling higher penetrations of wind generators and providing reactive power support. Voltages and reactive power are highly location dependent and what works for one area may not work for the other.

For the full case study, search www.epri.com for product number 1026589.

Exelon (ComEd and PECO)



Critical peak price and peak time rebate customers provided the largest demand reduction —up to 20%—while technology treatments added no measurable improvement.

The Exelon Smart Grid Host Site Demonstration includes the Commonwealth Edison (ComEd) Customer Applications Pilot (CAP) and a collaborative effort with the Philadelphia Electric Company (PECO), Drexel University, and Veridity. The ComEd pilot was a comprehensive customer behavior study to evaluate customer responses to varying types of pricing programs in combination with enabling technology and customer education and information services. PECO's portion of the smart grid demonstration is to develop and deploy an advanced distributed energy management system through a "smart campus" microgrid capable of aggregating dispatchable demand reduction resources to the regional grid.

Impact of Advanced Metering Infrastructure (AMI) on Demand Response - Commonwealth Edison Smart Grid Demonstration

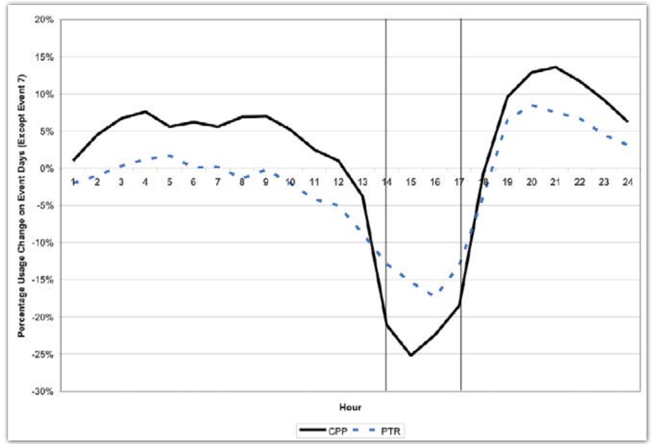
Commonwealth Edison conducted the Customer Applications Program (CAP) pilot to gain understanding of how advanced metering infrastructure (AMI) can enable changes in residential electricity consumption and load shapes. Benefits are projected to arise from enabling more customers to participate in price and demand response programs, resulting in demand and energy savings that accrue to all customers. Research suggests that AMI technology overcomes substantial barriers to customers' adjusting their usage in response to changes in the price they pay for electricity, or to other inducements invoked in response to potentially adverse supply conditions.

The CAP is notable for its novel design, scale, and extensive scope. Participants were engaged in the first large-scale opt-out method of enrollment. Approximately 8,000 residences out of a population of 130,000 AMI-metered customers in the greater Chicago area were assigned to treatments that involved five fundamentally and functionally different "applications" such as rate structures, and several means for providing customers with information about their usage. These included an in-home display (IHD) and a programmable communicating thermostat (PCT). The pilot was launched in April of 2010 and ended in May 2011.

Results

Although only 2% of the original enrollees opted out, low acceptance of information and control technologies created a sample size that was smaller than planned, which compromised the ability to detect relatively small but significant effects on usage. As a result, analysis based on aggregated data showed that information and technology treatments, on average, exhibited no statistically significant differences in the overall average usage compared to the control group. The same was the case for the pricing treatments, even those that at times offered participants inducement of over $1.74/kWh to reduce usage.

However, significant findings emerged from comprehensive analyses to first identify price responders and then quantify the extent of their response. A subset of dynamic rate customers, referred to as "event responders" were identified. The dynamic rates utilized were day-ahead real-time pricing (DA-RTP), critical peak pricing (CPP), and peak-time rebate (PTR).



Event-Day Load Estimates from CPP and PTR Event Responders

The event responders, who comprised 9-12 percent of the participants, reduced their load by 20 percent or more during event hours. The largest reductions came from the CPP customers and PTR customers, but all three dynamic pricing structures produced substantial response during high-price events.

Lessons Learned

- Statistically significant responses were exhibited by some of the customers served under each rate type. Responders constitute about 10 percent of all customers enrolled in a dynamic rate.
- An opt-out recruitment strategy without a purposeful and persistent customer support effort does not appear to encourage a greater response level than an opt-in deployment.
- More research is needed to establish the comparative effectiveness of opt-in and opt-out recruitment methods to fully understand the comparative costs and benefits of each.

For the full, publicly available case study, search www.epri.com for product number 1023644.

Exelon (ComEd and PECO)

Energy and cost savings can be achieved by a campus by automating building energy management and participating in electricity markets.

Drexel Smart Campus - PECO Smart Grid Demonstration

The overarching goal of the project was to create a "smart campus" at Drexel University in Philadelphia, Pennsylvania. The smart campus demonstrates automated control of campus buildings and achieves interoperability, lower peak demand, and load reduction, as well as electricity cost reduction via third party market participation.

Project Objectives

The project objectives were the following:

- To maximize benefits of smart grid technology
- To create an intelligent network to manage energy use by modeling the buildings involved and by balancing building operational needs with grid operations and costs
- To offer a template for replication in other markets
- To reduce energy costs; increase network reliability, efficiency, and potential for use of renewable resources

Objectives for demand response, a major component of the project, included establishing methods by which the university has the ability to accomplish the following:

- Observe the system status from a remote system location
- Optimize the operation in a nonlinear fashion in accordance with system operational goals, building occupancy, and consideration for current status
- Utilize and actuate automated system hardware

Project Hypotheses

- Compared to electrical systems, building HVAC controls have a longer system delay time and corresponding response time.
- Building HVAC systems contribute to a substantial percentage of the campus electric load.
- Buildings each have a different thermal mass resulting in unique characteristics regarding response when using HVAC systems as a key part of a demand response.
- Building characteristics can be modeled and then leveraged to optimize energy use.
- After they are optimized by input from building usage needs and patterns—along with building thermal model and HVAC characteristics—the buildings can be optimized for both energy savings and for cost savings for the Drexel campus.

Figure 1 – Drexel University campus

Figure 2 – Building management system screen

Results

The physical and financial results achieved are set forth below. Beyond these quantitative measures, the results also establish that remote, automated control of a building's assets can be an effective and efficient way to manage an HVAC system, with no negative effect upon school operations and with little disturbance to the daily workload of building facility personnel. From June 2010 to March 2013 this project achieved the following:

- Ten buildings are automatically and remotely controlled by Viridity's Network Operations Center. This is an increase from the initial deployment of 6 buildings. The building management system screen is shown in Figure 2.
- Load has been curtailed for over 874 hours, with no interruption to the school's business or any complaints of tenant discomfort.
- 158 MWh have been saved via the curtailments. The foregone consumption aids the school in its sustainability objectives as these negawatts reflect avoided carbon emissions.
- Average load response is 181 kW. The project team believes that more buildings are capable of load management and the revenue, retail savings, and environmental benefits all grow with added participation.
- Cumulative total energy reduction and savings of $127,553 (as of 1/31/14), includes:
  - PJM Energy Market—138 MWh of curtailment sold to PJM for an estimated gross revenue of $16,063 and retail savings from foregone consumption of $13,800
  - PJM Capacity Market—15 MWh sold yielding an estimated gross revenue of $85,669
  - PJM Emergency Energy—estimated gross revenue of $12,021

Lessons Learned

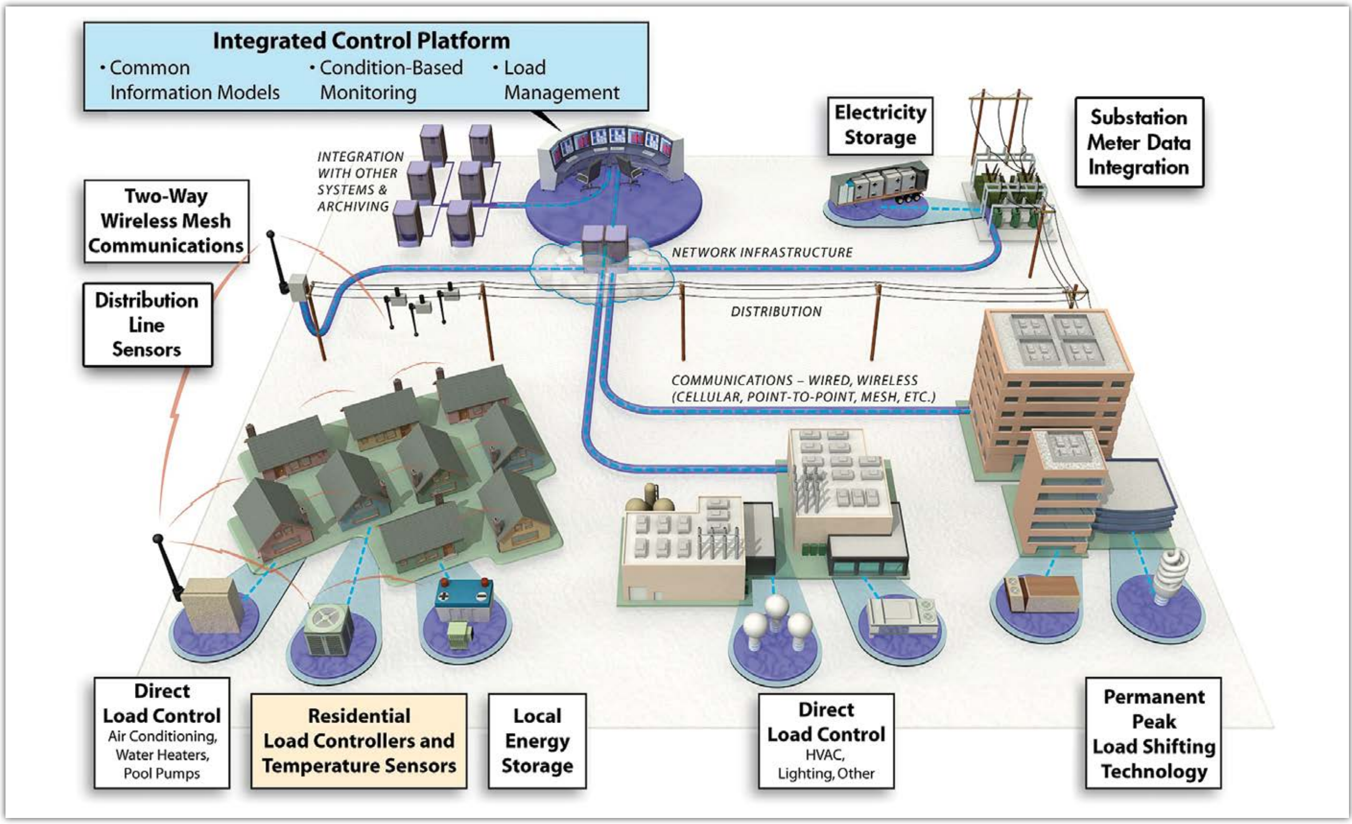
- Importance of meter selection and placement in smart building environments:
  - The number of meters/sub-meters are affected by the level of load diversity.
  - Capturing dynamic building characteristics requires increased sampling rates for meters.
  - Meter placement should be driven by the quality of demand response decisions versus computational efficacy of approach.
- Importance of close coordination between campus facilities and network operations:
  - Enhanced trust between partners is achieved through local monitoring of dispatch decisions with interrupt capability.
  - Sharing of experiences with local facility managers is important as it affects energy resource planning decisions.
  - In-house knowledge of campus networks lies with plant managers/operators.

Recommendations

- Evaluate the potential of the existing system by creating a topological model. Existing electrical drawings can be obtained through collaboration with facilities management and the local utility company.
- Identify the buildings that are most suitable for demand response control and update the sensing/actuating capabilities of these buildings if necessary. This may involve placement of sub-metering devices and the ability to access the readings remotely and/or automatically.
- Tune model parameters based on collected data.

For the full case study, please search www.epri.com for product number 3002002131.

FirstEnergy



Permanent peak load shifting using ice storage can contribute to better system management with the potential to defer infrastructure investment.

The FirstEnergy Integrated Distributed Energy Resource (IDER) Management Project, deployed in the central region of the Jersey Central Power & Light (JCP&L) operating company, is creating an infrastructure based on smart grid principles designed to enhance distribution system reliability and operations and leverage opportunities for participation in regional power markets. The project features an Integrated Control Platform and two-way communication systems for distribution system monitoring and support, peak load shifting, and optimum resource and asset usage.

Integrated Distributed Energy Resources Management: Device Installation and Commissioning

JCP&L/FirstEnergy's IDER Management Project is testing and demonstrating the value of real-time monitoring of distribution-system status and peak load management. Distributed resources, such as direct load control devices and ice-energy storage, allow lowering or shifting of customer electrical loads at individual and aggregated levels. Real-time information on distribution circuit status and load management capabilities are supplied through distribution line sensors and data from existing substation meters, all transmitted via a two-way communications network. An Integrated Control Platform, provided by BPL Global, is central to the system for data management, analysis and conversion of data into visual, actionable information.

This case study summarizes results of the performance of the technologies that comprise the integrated distributed energy resources management system. The major applications and technologies tested by JCP&L include:

Direct Load Control

Direct load control devices were installed on central air conditioning systems at 24,000 residential customer premises to achieve a total curtailable load of 38 megawatts (MW).

Premises equipment includes a controller and a temperature sensor, which are tied into a two-way 2.4GHz wireless mesh communications system and cellular backhaul to the Integrated Control Platform server. The controller monitors available active load and allows for control of loads by signaling the controller relay. The relay is wired into the air conditioner to intercept the thermostat control signal. The command from the ICP to turn off the air conditioner allows inside temperatures to rise to a predetermined level agreed to by the customer.

An opt-in method for recruiting direct load control participants was employed. A "green" sales message was featured, and inducements included potential bill savings and a $50 gift certificate. Solicitation was done through telemarketing, direct mail and, with greatest success, going door-to-door.

Permanent Peak Load Shifting

To evaluate capabilities of storage to shift cooling load while maintaining customer comfort, four Ice Energy's Ice Bear® electro-thermal storage units were installed at the office-product retailer Staples in Howell, New Jersey. The Ice Bear units create ice during off-peak periods, which chills refrigerant circulated to the air conditioning system. System performance monitoring showed successful cooling and peak shifting during summer peak seasons of 2010 and 2011.

Figure 1 – Ice Bear installation on roof of big box retailer

Distribution Line Sensors

To gain near real-time visibility into the status of the distribution system, two types of line sensors were used: 10 sets of PowerSense three-phase sensors were installed, as shown in the photo, to provide data on load current, power levels, voltage quality, disturbances in the grid, and distance to faults; and 20 single-phase Grid Sentry line sensors to collect data on current, outages, faults and other distribution system conditions. The sensors send their data to the Integrated Control Platform using cellular telecommunications.

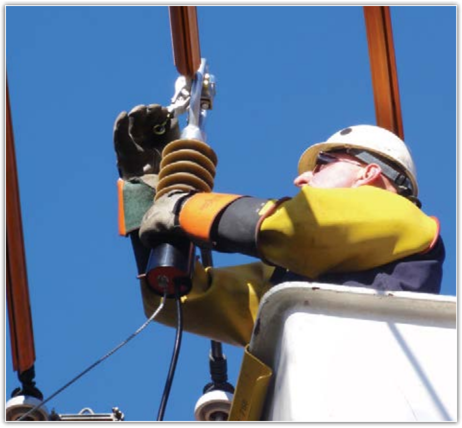


Figure 2 – PowerSense installation

Substation Meter Data Integration

Communications equipment using cellular telecommunications was installed and integrated during 2011 and 2012 to automate gathering of substation transformer and circuit condition data from existing Satec meters at four substations in the targeted area. Collected data includes load current, line voltage, power factor, frequency, real power and apparent power.

Results and Lessons Learned

- Eighteen direct load control load-curtailment tests and events were successful. These included events to support distribution operation and tests for PJM market participation. They show that revenue goals can be achieved by participating in the power market using aggregated customer resources.
- Direct load control device density is important to achieve communication coverage for wireless mesh networks. Focusing customer solicitation efforts in defined areas is critical.
- Response to the direct load control program achieved high levels, at a 17% enrollment rate and an attrition rate of 10% of enrollees. Door-to-door solicitation proved to be the most effective form of recruitment.
- Evaluation of permanent peak load shift using ice storage indicates that it can contribute to better system management with the potential to defer infrastructure investment.
- Each of the Ice Bear units stored an estimated 32 kWh of energy in 10 off-peak hours and reduced an estimated 5 kW of site energy demand for up to and over a six-hour, on-peak period. There was over an 18 kW reduction at the site, which equates to 20.4 kW at the PJM bus.
- Distribution line sensor data has enhanced monitoring, including pinpointing the location of non-operational capacitor banks.
- Substation and circuit conditions data, presented in near real time via a web-based visualization tool, is being used by engineers to optimize maintenance schedules and projects.

For the full case study, search www.epri.com for product number 3002002133.

FirstEnergy

The Integrated Control Platform Visualization provides an integrated view of electric distribution system operating conditions to enhance operations, improve maintenance methods, and resolve customer issues more quickly.

Integrated Control Platform Visualization

This FirstEnergy case study describes the Integrated Control Platform Visualization (ICPV) tool deployed and used in an area of JCP&L. The ICPV was developed with BPL Global to provide an integrated, comprehensive view of information related to the operation of the distribution system. The resulting system provides near real-time information about the condition of the distribution system that has not been accessible before. Historical information is also available for troubleshooting and planning purposes. There are four types of devices from which data is displayed via the ICPV: direct load control devices, distribution line sensors, substation meters and ice storage equipment for permanent peak load shifting.

Technology Features

The visualization tool has the following features:

- Web-based user interface with encryption and preference selections.
- JCP&L Service Territory map with substation hyperlinks (see Figure 1) as well as a geographic view showing the location of devices.
- Navigation and search feature in left panel. Navigation uses a "tree" structure enabling drill down to levels such as system, substation, bank, circuit, and device.
- Circuit schematic showing three-phase current data with hyperlinks to Satec Meter, PowerSense (PS), and Grid Sentry (GS) pages. See Figure 2.
- Trending Applet that opens when a field inside the data box is clicked. It opens a default graph of the previous 24-hours of data, and the graph image can be configured, exported, and saved. A Data Point Picker selection can show up to nine device metrics. The trend data can also be shown in tabular form.

Use, Results & Lessons Learned

After a year of development, the system has been used regularly by engineering and dispatch office personnel. Samples on how the information has been used include:

- The ICPV provides circuit load balance information that can support the company's regulatory requirement to keep phases within 15% balance.
- Satec meters do not store any data so integrating into the ICP gives engineers and planners historical circuit and capacitor bank load profiles. This information can be used to determine a window of time for load transfers so that transformer bank maintenance can be performed without the use of mobile substations.
- Grid Sentry units can be installed quickly and easily on the line conductor with a hot stick.
  This allows them to be deployed quickly to monitor conditions at specific locations to resolve circuit problems.
- JCP&L was able to quickly address and resolve a voltage problem by utilizing the ICPV. Upon notification of abnormal operation, JCP&L engineers used the ICPV tool to analyze available real-time and historic data immediately. The data indicated erratic capacitor bank switching, as shown in Figure 3. This problem was resolved on the same day by initiating a truck roll to take the capacitor bank off line for further analysis and repair. It was returned to service that day, which is shown in the graph at 10 pm.

Next Steps

Activities under consideration are operator configurable alarms, query for maximum or minimum data over a range of time (i.e., maximum load on a circuit in a month), adding other data points available from meters to the ICPV such as phase balance information from Satec and harmonics from PowerSense, and linkage to PI historian and/or a SCADA system.

For the full case study, search www.epri.com for product number 3002004662.

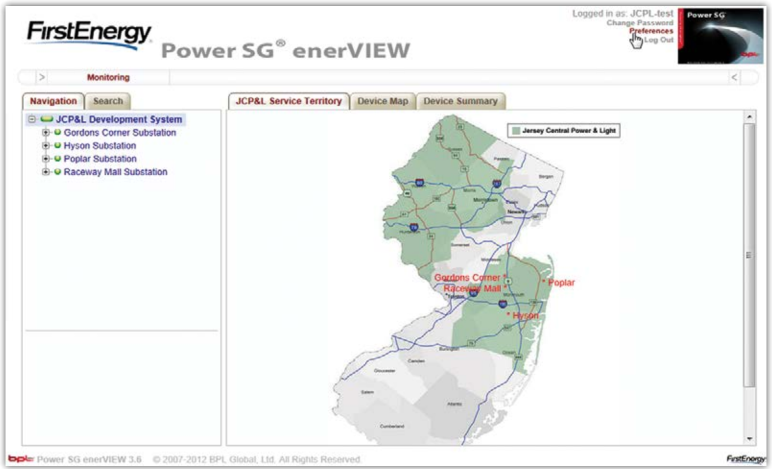


Figure 1 – Map with substation hyperlinks

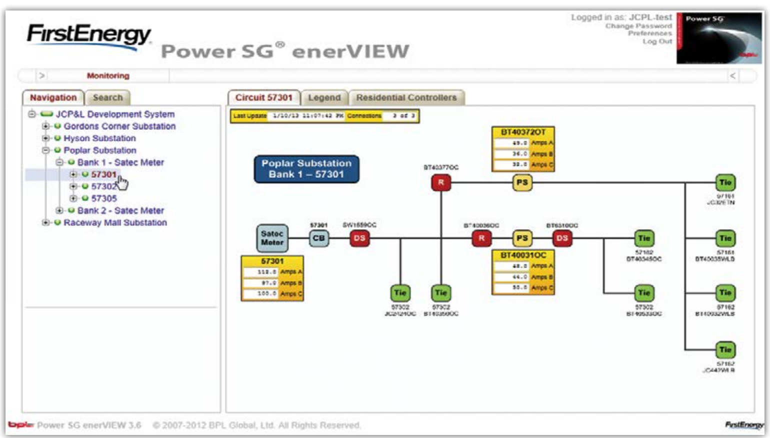


Figure 2 – Circuit schematic

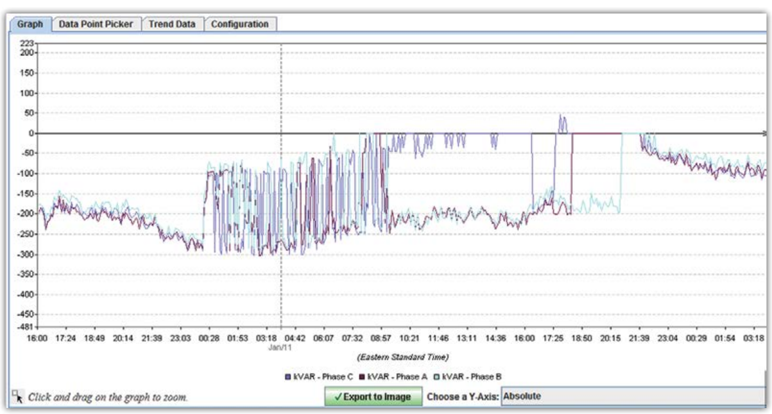


Figure 3 – Capacitor bank operation showing erratic operations on all 3 phases

FirstEnergy

Advanced two-way communicating direct load control of customer air conditioning aggregated by JCP&L/FirstEnergy showed that it met the participation requirements of the PJM Interconnection regional transmission electricity market programs. Although the technology met operational requirements, there is uncertainty in the changing electricity markets and therefore risk associated with long-term investments.

PJM Market Program Participation

FirstEnergy's electric distribution company, Jersey Central Power & Light Company (JCP&L) implemented an Integrated Distributed Energy Resources (IDER) Management project that tested direct load control (DLC) of residential customers' air conditioners with two-way communications beginning in 2009. The DLC was utilized in market programs with PJM Interconnection, the regional transmission operator for the mid-Atlantic and mid-west United States. PJM (www.pjm.com) manages market programs governed by the Federal Energy Regulatory Commission and operates a competitive wholesale electricity market as a part of managing the high-voltage electricity grid to ensure reliability for more than 61 million people.

Design and Deployment

JCP&L/FirstEnergy participated in the PJM Demand Response Program where end-use customers reduce their load during emergency events. Customers participate through curtailment service providers (CSPs), who act as their agents. JCP&L is a CSP and has used the IDER system in the PJM Emergency Load Response Program, Limited Demand Resource, Full Program Option program where mandatory events can be called in the four summer months, June-September. These events have a one-hour advance notification, a duration of up to 6 hours, and can be called up to 10 events per season. The IDER DLC system is registered as a short lead-time resource, which means that once the load reduction request is received, JCP&L is required to respond within one hour.

The IDER DLC system was designed to support both JCP&L operations and PJM market participation as part of a co-development project between FirstEnergy and BPL Global with support from the New Jersey Board of Public Utilities and funding from the United States Department of Energy, American Recovery and Reinvestment Act, Smart Grid Investment Grant.

To participate in the PJM Emergency Load Response market programs, a load control technology must respond to a PJM request to reduce load. An emergency request means that additional capacity is needed to meet electric demand and a call is sent out to registered emergency capacity program participants. Event performance is based on the average load drop during the event.

Initially JCP&L participated in an unmetered pilot program via a protocol, approved by PJM, to determine the deemed savings for each event. Later, PJM approved certification of the DLC controllers for a measured aggregated MW per hour value which then qualified the system to become a full Program Option, Emergency Load Response participant. This increased the load drop from 1.302 kW/point to an average ranging between 1.5 and 2.35 kW/point. The load reduction test event information from August 10, 2009 is shown in the table and the Figure 1 graph, and exemplifies the difference certification provided.

Hour Ending	4:00 PM	5:00 PM	6:00 PM	7:00 PM
PJM Actual Load Drop - kW	2088	5141	5900	3355
PJM Deemed Savings - kW	2018	3415	3267	3176

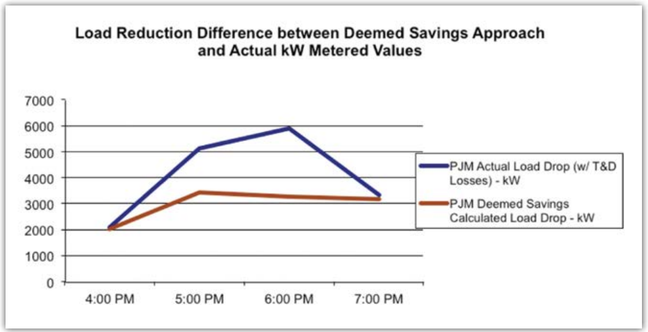


Figure 1

To meet the MW registration capacity commitment, the system maintains an ordered list of available air conditioning units based on the participation choice selected by the customer to allow the residence to increase in temperature plus 6° or 9° F. A total of 25,536 controllers were installed in 30 substation areas at individual homes. The IDER system monitors and controls the air conditioning loads at individual and aggregated levels by substation, transformer, and circuit in near real-time (see Figure 2).

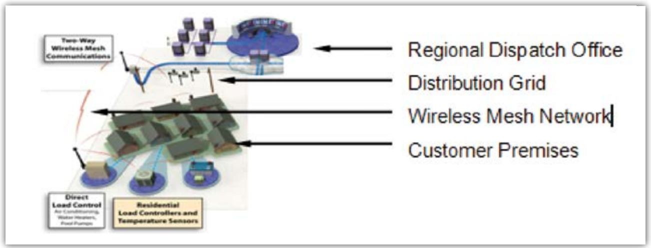


Figure 2 – Direct load control schematic

The IDER DLC platform is managed by operators in the Regional Dispatch Office in Red Bank, NJ, to create curtailment events to fulfill PJM commitments. The user interface provides the Regional Dispatch Operator with detailed information regarding the operating, available and controlled load.

Results

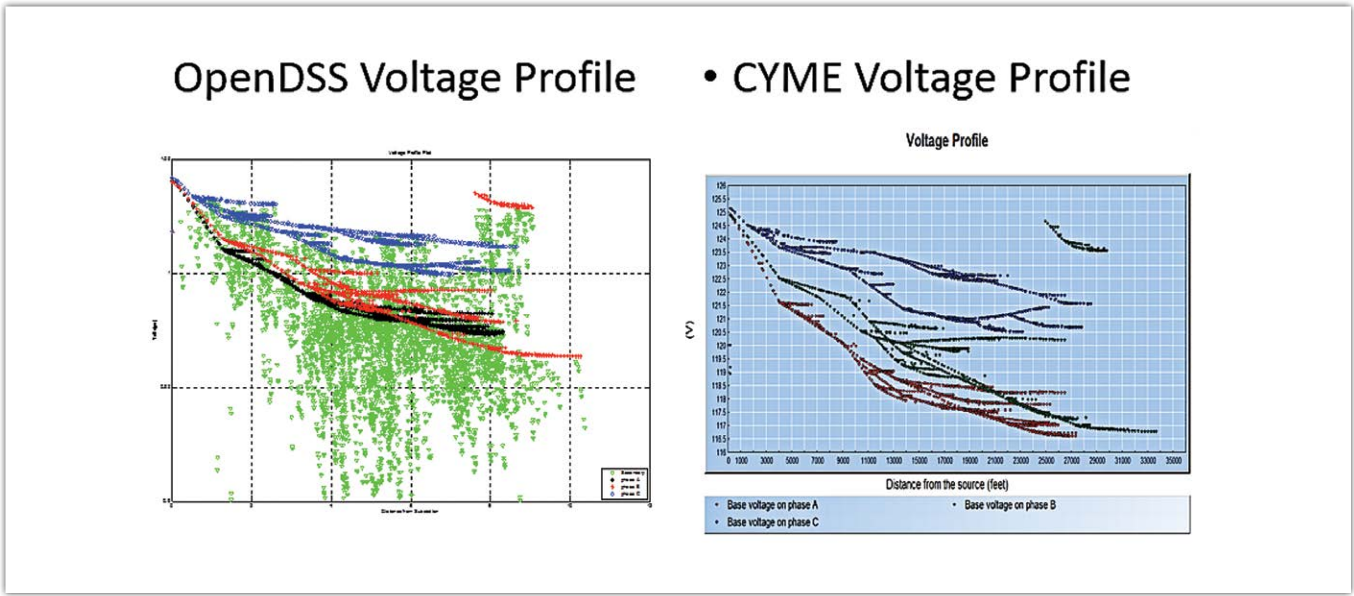
The IDER DLC project demonstrated the capability to participate in the PJM emergency capacity market from 2009-2014. In 2009, 5 MWs were registered and up to 38 MW of curtailable load became controllable as more equipment was deployed. Program operations supported reductions of JCP&L's PJM capacity obligations and generated revenues that flowed back to JCP&L ratepayers.

Lessons Learned

- The project technology showed that it can meet the PJM market program operations requirement.
- There is uncertainty and therefore risk regarding changing electricity market conditions and these risks need to be carefully evaluated. For example, PJM has changed program rules and capacity prices have lowered, thus reducing the cost-effectiveness of the program. As a result, the IDER DLC program is only planned to be operated through the 2015 energy year.
- Voluntary program market participation is subject to customer fatigue and opting-out. Residential customers showed an initial willingness to enroll in the program, with a one-time incentive of $50. However, recurring incentives may be needed, as customer attrition has been ~8% per year which has reduced the load available to be curtailed.
- Customers need to be informed of events as soon as possible so they can pre-cool or make other arrangements. Based on experience with this project, FirstEnergy now notifies customers through FirstEnergy's Automated Customer Call Back System as soon as an event is called.

For the full case study, search www.epri.com for product number 3002004495.

FirstEnergy



OpenDSS vs. CYME comparison | Example Feeder – Voltage Profiles

> *Creating OpenDSS models directly from GIS information and an equipment catalog database can yield accurate circuit and supply models for distributed resource integration.*

Electric Power Distribution Modeling and Simulation for Feeder Analytics and Distributed Energy Resource Integration

This objective of this research project is to create new tools and concepts for the advancement of distribution feeder analytics. A team from FirstEnergy and the University of Pittsburgh is developing advanced analytical applications that will help FirstEnergy analyze and integrate load, energy storage, and distributed generation on the electric distribution system. Data for the project was collected as part of the FirstEnergy Integrated Distributed Energy Resource (IDER) project.

Approach

FirstEnergy provided distribution circuit information with geospatial information system (GIS) and electrical data collected from IDER sensors and meters to the University of Pittsburgh engineers so that they could conduct several analytical investigations. The analytical investigations included:

- Power – load profile
- Voltage profile by phase
- Comparison between IDER SATEC meter data and Jersey Central Power & Light SCADA PI data to validate the data
- Volt-var analysis
- Photovoltaics hosting capacity analysis
- Long term - load switching capabilities

The team used the EPRI OpenDSS modeling software to perform the analysis work. To use OpenDSS, a data translator program developed to take the FirstEnergy GIS data from the mapping system and from equipment information in catalog database systems. This enabled the team to create models of the distribution circuits under evaluation. Previously, OpenDSS models were created by manually extracting information out of the CYME distribution planning software models, which had been extracted from GIS. Through use and analysis, it was determined that this two-step conversion process complicated the verification, augmentation, and maintenance of OpenDSS models.

The graphic shows a comparison of the outputs of the two different models. The two charts show the voltage profile on CYME and OpenDSS for an example circuit under study. This comparison was necessary to validate the action between the two models of the proposed distribution system. In CYME, distribution secondary conductors and services are not included in the model due to the run time to produce results, but are included and shown in the OpenDSS model because it is able to run very quickly and accurately. While the charts are on different scales, the output shows similar results for both modeling systems.

Results

The project team decided that creating OpenDSS models directly from the GIS information and equipment catalog database would yield the most accurate and detailed circuit and supply models for distributed resource integration. The programming language PERL was employed. Once the PERL script software was created, it was tested and verified on several example substations and circuits.

The PERL scripts could produce OpenDSS models quickly on any circuit in the FirstEnergy system including all operating companies; for historical reasons, each operating company built its GIS database differently. The code performs all steps of the OpenDSS model building process directly from source data, and manual adjustments to the model have been minimized.

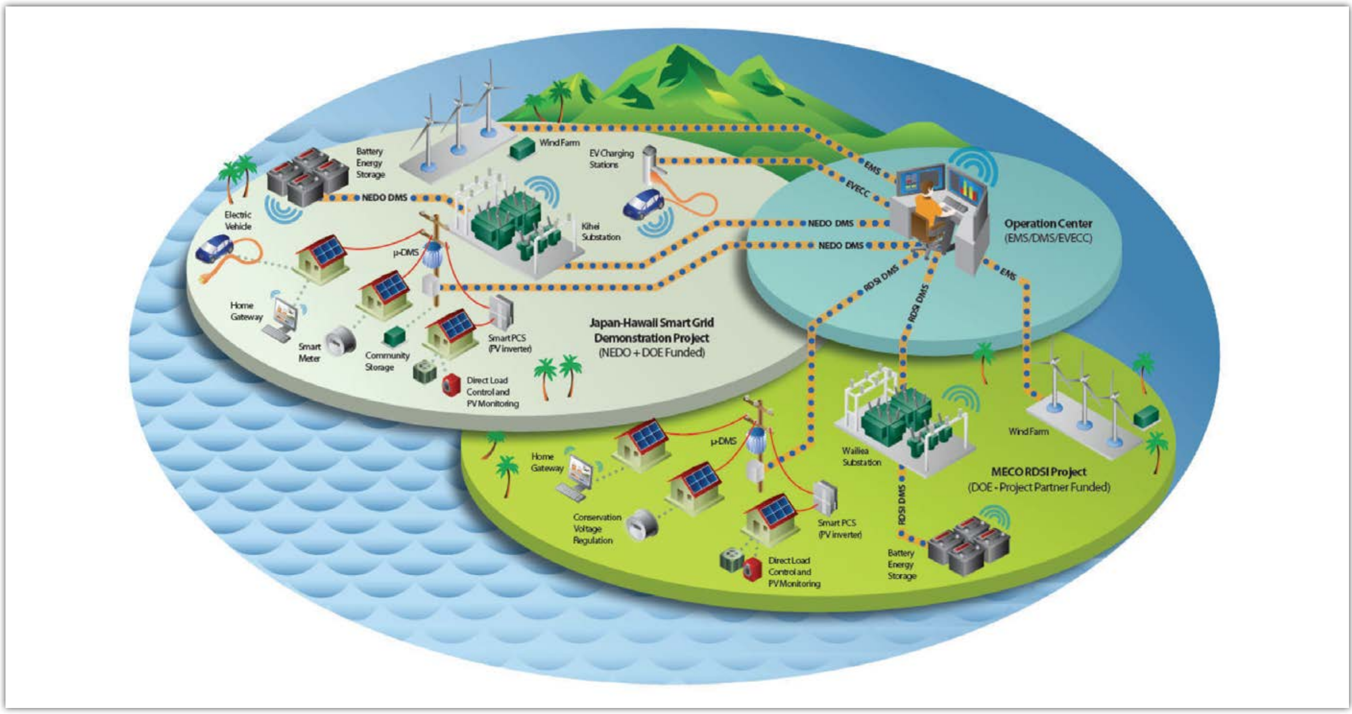
Once the new OpenDSS model creation process was completed, the team analyzed the difference between the typical PI historian load data collected from the substation through SCADA, and the detailed substation, transformer bank, and circuit data collected by the sensors and meters. Three-phase data from the IDER sensors was compared with the PI historian three-phase data for verification and confirmation. The individual per phase data from the detailed sensors were input into the OpenDSS system models for more detailed load allocation by phase and circuit segment. Circuit efficiency and load profile analyses were run for the newly created models on an hourly basis. Solar generation profiles for the photovoltaic sources on the system were input for analysis of PV and volt-var response. PV hosting capacity and long term switching capabilities were input for analysis of variability of PV and volt-var response. These analyses provided confidence in the results derived from the OpenDSS.

Next Steps

The visualization phase of the project, being conducted in the last half of 2014, is to deploy a software package on FirstEnergy web servers. This software uses OpenDSS as its engine, but allows the user to perform impact analyses of the integration of DER on the distribution system through a browser interface. Future work could include determining the potential required settings on multi-quadrant inverters (smart inverters) to integrate their capabilities into the distribution system.

For the full case study, scheduled for publication at the end of 2014, search www.epri.com for product number 3002004625.

Hawaiian Electric Company



> *The simulation results show that the projects have insignificant impacts regarding voltage regulation, thermal loading of the circuit, short circuit current, protection, and power quality and load rejection overvoltage during islanding condition.*

The state of Hawaii continues to increase the use of its indigenous renewable resources like solar, wind, waste-to-energy, geothermal, and wave-technologies at a rapid pace. The percentage of renewable generation will continue to increase due to Hawaii's extremely aggressive renewable portfolio, which has a target of 70% clean energy by 2030. To respond to reliability issues inherent in adding large amounts of distributed renewable generation on an isolated island electric system, Hawaiian Electric Company is working on smart grid projects with Maui Electric.

Interconnection Requirements Study for Battery Energy Storage Systems on Maui Electric's 12.47 kV Distribution Circuit

This case study is about the interconnection requirements for the two Hitachi battery systems to be interconnected to Maui Electric's 12.47 kV distribution circuit fed by the Kihei substation. The study feeder is located in Kihei on Maui Island, as shown in the figure below.

The study was conducted by Pterra Consulting, LLC for Hawaiian Electric. The objective of the study was to determine the impacts attributable to the battery projects, and any mitigation options, for the following technical aspects: feeder load flow, short circuit and relay coordination, islanding, grounding and ground fault overvoltage, and harmonics.

The battery systems are manufactured by Hitachi, Ltd. with specifications as follows:

- Project 1: One Long Life Lead Acid battery has a 500 kVA inverter, 576 kWh capacity, maximum output/discharge 250 kW, and maximum charge 135 kW. The plan calls for the battery to be installed at the Waste Water Treatment Plant.
- Project 2: One Lithium-Ion battery has a 500 kVA inverter, 153 kWh capacity, max output /discharge 500 kW, and maximum charge 500 kW. The plan calls for the battery to be installed near the Maui Economic Development Board (near the end of the circuit).

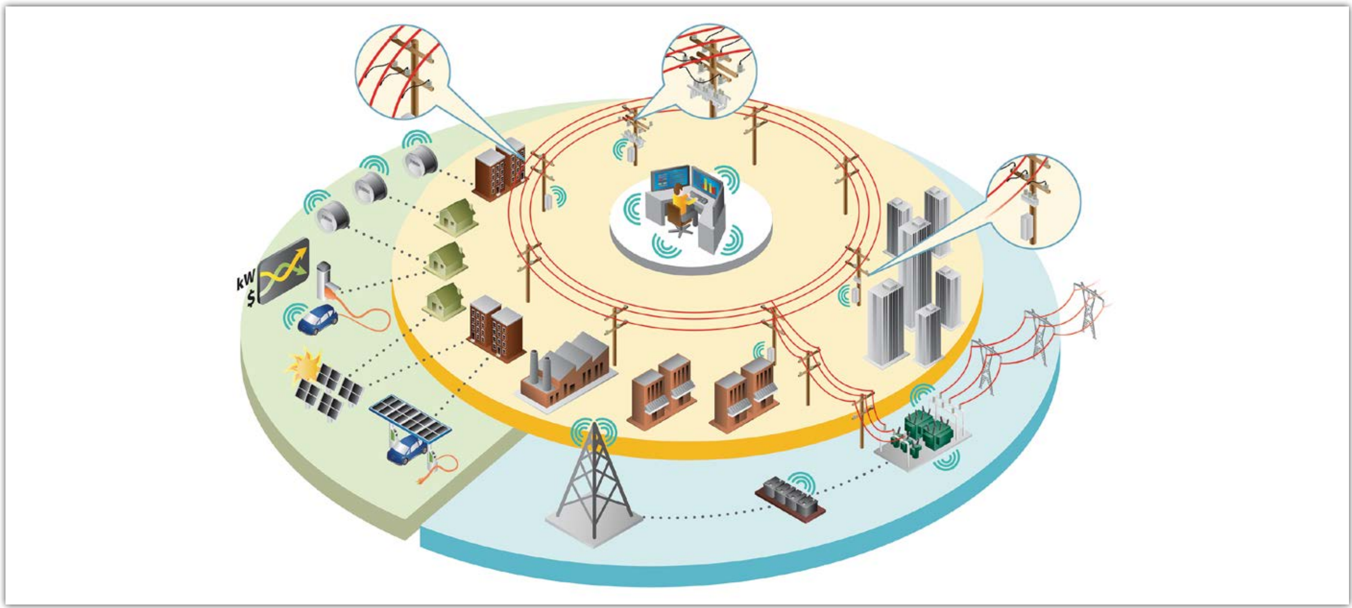
Advanced computer modeling and simulations were performed with commercial software packages Aspen OneLiner™ and PSCAD™/EMTDC™ in the time and frequency domains. The simulation results show that the projects have insignificant impacts regarding voltage regulation, thermal loading of the circuit, short circuit current, protection, and power quality and load rejection overvoltage during islanding condition.

Results

- The addition of battery systems to the study feeder will not impact the voltage performance of the existing grid significantly, assuming they are charging and discharging at constant rates.
- The projects have a potential risk of overvoltage because the projects don't have an effective grounding system. Besides the embedded anti-islanding control, installation of a grounding transformer on the 480 V side of the projects' step-up transformer could provide a second layer of protection. However, the grounding bank may not be necessary if the projects discharge during the evening only, and are only in charging mode during the day time.
- Simulations demonstrated that potential temporary overvoltage due to the load rejection is below the limits of 10 kV surge arresters and EPRI 1010892 damage curves for residential loads and surge suppressors. Additionally if the projects discharge during the evening only, and are only in charging mode during the day time, the risk will be further mitigated. The projects would not have a potential risk of out-of-phase reclosing because of the proper coordination of the substation breaker reclosing and the protection tripping of the projects.
- The ITIC (Information Technology Industry Council) Curve may be more conservative than necessary. It is proposed that the overvoltage magnitude and duration should be below the left edge of HECO 10 kV surge arrester curve and EPRI 1010892 damage curves for residential loads and surge suppressor.
- It is recommended that the inverter voltage and frequency setting follows IEEE Std. 1547 and the HECO/MECO requirement. In addition to the IEEE Std. 1547 default setting of 1.2 p.u. overvoltage with 10 cycles tripping time, another setting with higher voltage but with instantaneous tripping time should be added in order to reduce potential damage due to overvoltage,
- For an islanding event, the projects' inverters have to be able to detect and shut down within 2 seconds. The National Electrical Code® requires that utility-interactive inverters be listed (certified) for this purpose, and the listing process tests the inverter using a standard test circuit and test method that has been determined to be a worst case condition and is part of the UL1741 standard. If the projects' inverters are not UL1741 certified, the manufacturer should be consulted to ensure that the inverter could trip within 2 seconds after islanding is formed.

For the full case study, search www.epri.com for product number 3002003602.

Hydro-Québec



Hydro-Québec found that autoground can be an attractive solution because of the cost reduction relative to the transfer-trip approach.

The Hydro-Québec Smart Grid Demonstration project focuses on performance and interoperability of a smart distribution system, consisting of a number of advanced distribution applications and the associated technologies. These include advanced metering infrastructure (AMI), conservation voltage reduction, volt-var control, demand response, electric vehicles, distributed generation, and a distribution management system.

Anti-islanding Protection of Distributed Generation using Autoground

Hydro-Québec tested an alternate approach for anti-islanding protection, referred to as an autoground, which was proposed in the context of the IEEE 1547.8 recommended practices working group. The premise of the autoground concept is to allow the distributed generation (DG) system time to detect the islanding situation. This is done using a passive approach up until the moment just prior to reclosing of the substation breaker, at which point the autoground momentarily short circuits the feeder, forcing any remaining DG to disconnect based on line protection.

Project Objectives

The intent of the project was to build and test the concept, using, as much as possible, components already certified for use on the utility's system. Specifically, the objectives were:

- Design of the appropriate power system apparatus to realize the autoground concept.
- Develop the relay logic in order to coordinate the operation of the autoground's sectionalizing and the autoground switches with the substation breaker.
- Evaluate by testing the system for back-up anti-islanding protection of a synchronous-machine-based distributed generator.

Research and Results

Autogrounding addresses the problem of anti-islanding protection for one or multiple DG units on the same feeder. The table on the top of the following page summarizes the autoground concept as well as many of the other technologies proposed for anti-islanding protection. Each varies in terms of where it is implemented, equipment requirements, and cost. Since the autoground offered a desirable balance between cost and technical performance, it was selected by Hydro-Québec for a detailed evaluation.

Comparison of Anti-islanding Protection Alternatives				
Technology	**Equipment Requirements**	**Installation Site**	**Relative Cost**	**Pros/Cons**
Protection based on local measurements	- PT/CT - Microprocessor based relay	DG site	Low	- Low cost - Non-detection zones
Transfer-trip	- High fidelity telecom link (fiber or equivalent) - Microprocessor based relay	Substation and DG site	Very high	- Nearly foolproof but high cost - Link required for each DG resource
Secondary voltage restraint	- Secondary PTs - Modifications to breaker reclosing logic	Substation	Substation	- Single installation point - Breaker locks out if voltage detected
Autoground	- Recloser - Vacuum bottle switches	First two poles after substation	Moderate	- Single installation point - Low cost - Unproven in the field - Potentially applies fault to DG resource

PT - potential transformer, CT - current transformer

Left is sectionalizing switch; middle and right show autoground switch

The autoground technology was installed on two adjacent poles, the first housing the sectionalizing switch and the second the autoground switch. The sectionalized switch was realized by a standard recloser (Joslyn Trimode 700M version 2). The autoground switch was realized using Joslyn vacuum bottle switches, those typically used in capacitor bank applications. Each of the switches is connected to the medium voltage line (25 kV) through fuses, while the secondary (typical load-side connection) is connected directly to the neutral conductor. In addition to the power system apparatus for each of the switches, the autoground controller was implemented using a SEL-351 relay.

The generator used in the test is a synchronous generator, mechanically coupled with a 200 kW induction machine and drive.

The primary result of the study is that the autoground functions well with a synchronous-generator-based DG resource, forcing the disconnection of the generator successfully for each of three cases shown in the following table at right.

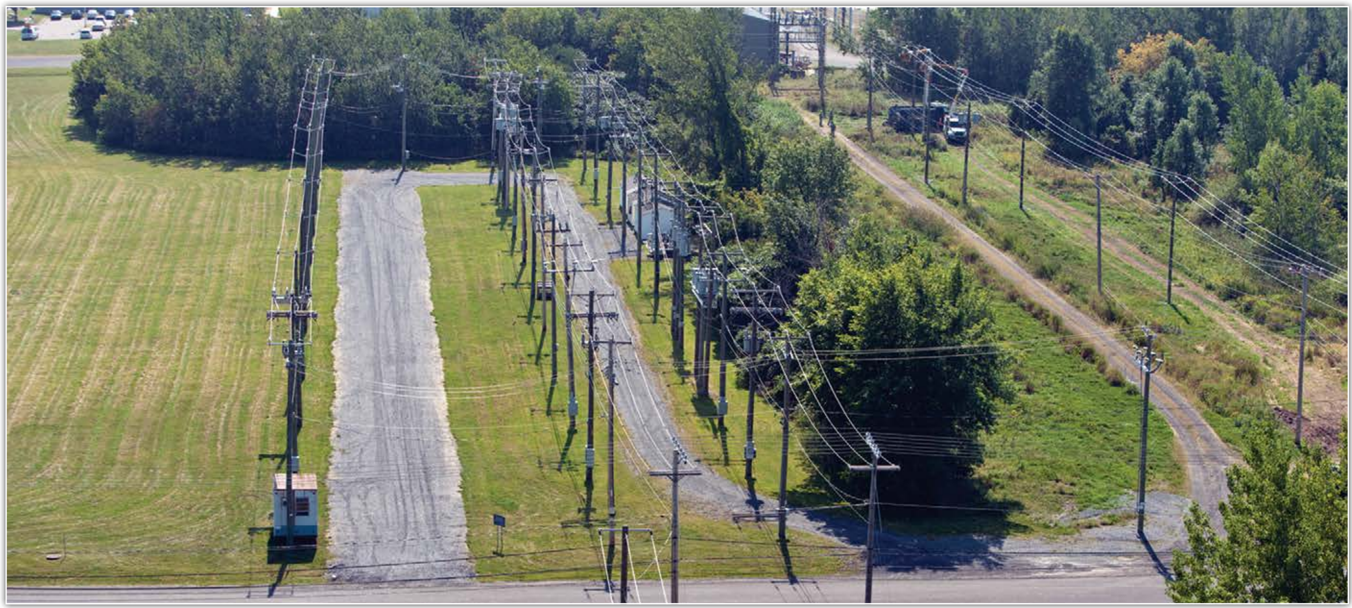
Test Conditions	Peak Current (at 600V) [A]	Step Voltage (at 1 m) [Vpeak]	Neutral Current [Apeak]	Torque [N.m – Newton meters]
Three phase	3500	0.729	92	>45
Two phase	3900	3.608	394	>45
Single phase	4100	3.438	856	>45

Lessons Learned

- The ability of the solution to provide secondary anti-islanding protection was demonstrated.
- Testing revealed that for a synchronous machine (where the risk of developing a stable island is greatest), the autoground can be used effectively to force the generator to disconnect using overcurrent protection.
- Some engineering is required in order to build the autoground, but it can be developed using standard distribution apparatus. Understanding the control logic and the implications of the technology in the context of the present distribution protection philosophy are prerequisites to implementing it as a solution. Specifically, understanding of the reclosing times and the number of reclosing operations is needed.
- Assuming the autoground is configured to operate just prior to reclosing, the generator's anti-islanding protection will operate long before the short circuit is applied. The autoground solution is for back-up anti-islanding protection in the highly improbable case that a stable island is formed. If this is the case, the generators within the island will be exposed to a short circuit, but one that will be less severe than a bolted fault at the generators terminal, the case to which its short-circuit capability should be designed.

For the full, publicly available case study, search www.epri.com for product number 3002001375.

Hydro-Québec



Automation remains a challenging piece of the puzzle in smart grid applications. Significant time and energy was consumed in properly integrating the controller with the SCADA system.

Testing and Certification of Equipment for a Volt-Var Control Application

This is a case study on experience gained in the certification and testing of the various distribution devices used by Hydro-Québec and many other utilities in volt-var control projects. The devices evaluated were voltage monitoring stations, capacitor banks, vacuum bottle interrupters used for switched capacitor banks, and automation controllers.

Project Objectives

- Evaluate the accuracy of voltage monitoring stations.
- Assess vacuum bottle interrupters used in capacitor banks.
- Analyze the power quality impact of capacitor switching.
- Validate automation and connectivity of devices.

Test Procedures and Results

Hydro-Québec has an internal standard to formalize the adoption and certification of new volt-var equipment. The standard calls for selection of at least two different vendors in order to increase competitiveness, and to hedge against risks associated with a single vendor. It also requires researchers to visit the facilities where tested equipment is manufactured.

Voltage Monitoring Stations

High precision accuracy (less than 0.3 % error) can be obtained from dedicated voltage monitoring stations. The selected medium voltage monitoring stations, as shown in Figure 1, used potential transformers (PTs) specified to an accuracy of 0.3 %. These met accuracy specifications as long as the burden was within operating limits. Hydro-Québec also determined that reasonable levels of accuracy could be obtained from standard distribution transformers, as well as integrated sensors in other distribution equipment. In addition, testing showed that dry type transformers used in the voltage monitoring stations have a secondary benefit of aiding in automatic fault location.

Capacitor Banks

Six capacitor bank units from three manufacturers were evaluated using the Canadian Standard Association standard CSA-C60871-1-03. This standard details procedures for the following tests: voltage withstand test, capacitance measurement, and measurement of dielectric losses. All of the capacitor banks easily surpassed specifications. Results showed that all the capacitors, rated for 14.4 kV (line-to-ground), were able to withstand the voltage of 23.3 kV. Capacitance values were within 1% of the specifications and dielectric losses were less than those specified by the manufacturers' datasheets.

Figure 1 – Medium voltage monitoring stations

Vacuum Bottle Interrupters

Vacuum bottle interrupters from two manufacturers were selected for electrical and mechanical tests, and were found to be robust. Mechanical tests were done on the assembly, which was validated by line crew personnel and engineers. Electrical tests included subjecting each of the interrupters to 5,000 operations, which far exceed the rated number of operations of 1,200 per interrupter. The vacuum bottle interrupters performed all operations with only a slight degradation in dielectric capacity. In addition, the power quality monitoring of the switching operations of the interrupters revealed no power quality issues.

Figure 2 – Automated distribution capacitor banks

Automation of Controllers

The controllers and their integration with the command center were tested on the Hydro-Québec distribution test line (shown in photo on page 12), using the control center dedicated to the test line. They were also tested in the automation lab. Numerous iterations between Hydro-Québec engineers and the gateway vendor were required to resolve connectivity issues. Automation remains a challenging piece of the puzzle in smart grid applications. Significant time and energy was consumed in properly integrating the controller with the SCADA system.

Lessons Learned from the Field

- Ceramic insulators are preferred to solid isolation in "pollution zone" environments with salt water to avoid isolation failure and even an explosion of the vacuum interrupter.
- Objections by local municipalities can be minimized by designing a control cabinet that is the width of a typical distribution pole and painted a color matching the pole.
- While vendors may have strong expertise in technology and systems related to automation, their limited knowledge of the power system conditions to which the equipment is exposed—both environmental and electromagnetic—can lead to designs that have limitations in the field.
- Industry tests such as IEEE 1613, or those from the IEC (International Electrotechnical Commission), cover a range of conditions; however, Hydro-Québec reports that there seems to be a gap with regards to the automation of distribution capacitor banks where standard phone lines are used for telecommunication.

Recommendations

Hydro-Québec recommends that utilities have a strategy for automating distribution equipment and integrating automated distribution equipment with SCADA systems. This is needed to achieve successful deployment of smart grid applications such as volt-var control. Testing and validation early in the process of system design and product selection will pay dividends later.

For the full case study, search www.epri.com for product number 3002001379.

Hydro-Québec

Line protection of distributed generation installations employing power electronics should be complemented with voltage controlled overcurrent protection.

Evaluating the Protection Impacts Associated with the Integration of a Wind Park on the Distribution System

In 2014-15, Hydro-Québec will have integrated roughly 150 MW of wind into its distribution network. This integration will come in the form of five different wind parks that are served from a weak rural distribution system. This case study details the analysis of the protection impacts associated with the integration of a large (by distribution standards) wind park into a distribution network. Specifically, the study attempts to validate overcurrent protection coordination in the presence of the wind park, and to assess the risk of anti-islanding. This was done for two types of wind energy converter (WEC) topologies: the doubly-fed induction generator (Type 3) and the full converter (Type 4).

Both topologies can contribute to system control through two advanced features: voltage regulation and inertia response. Voltage regulation means that the wind park controller dispatches the reactive power of the individual WEC in order to control the voltage at the point of common coupling. Inertial response is a control function by which the wind park boosts it power output momentarily during a drop in frequency.

Independent of the WEC topology, the interconnection protection must provide two main functions: line protection for fault detection and anti-islanding protection. Some form of grounding transformer is generally required, with or without a grounding impedance. This equipment is used to protect against overvoltages, with an appropriate selected grounding impedance to limit the single-line-to-ground-fault contribution of the installation. Line and ground overcurrent protection are usually employed for line detection, whereas voltage and frequency relays are used to identify islanding conditions.

Objectives

- Evaluate line protection approaches for wind parks connecting to distribution system.
- Determine whether the risk of islanding is sufficiently high to warrant the use of a transfer-trip scheme for anti-islanding protection of these wind parks.

Methodology

Both islanding and fault studies where power electronic interfaces are used require detailed modeling of the WEC controls and of the interface with the grid. These features dictate the dynamic behavior during an islanding or fault event, and consequently the system to which they are connected. The step prior to conducting the studies was to export the network model from CYMDIST to Hypersim, a parallel electromagnetic transient modeling tool. The simplified feeder model with the protective zones is shown below in Figure 1.

Results

A protection coordination study validates proper coordination of protection devices for the ensemble of faults that might occur in a distribution network. Figure 2 shows the magnitude of the fault currents for various types of faults imposed at the four busses of interest.

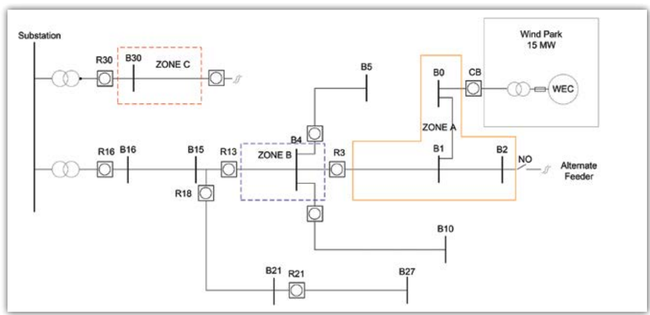


Figure 1 – Simplified feeder model with protective zones

The magnitude of the faults is relatively small due to the system being relatively weak. This in turn causes the operating times of reclosers to be longer to ensure proper coordination. Figures 3A and 3B show the trip times associated with the system reclosers and the wind park breaker (Figure 3A, DP) and the relays that control the wind park breaker for a fault on bus 27 (Figure 3B). For this rare case, there is potential for nuisance tripping of the wind park voltage controlled overcurrent relay (Figure 3B, 51Vc) for specific types of faults.

Below are other key findings of the study:

- Type 3 and 4 WEC produce near nominal fault current, making it extremely difficult to detect all faults using a line protection strategy based solely on overcurrent protection.
- Using a line protection strategy based on voltage controlled overcurrent, configured with the pick-up current of a single WEC and the voltage thresholds consistent with the undervoltage protection, enabled coverage of all faults.

- Islanding detection times for the wind park employing Type 3 WEC were generally under 1 second. In certain cases, the maximum detection time was exceeded indicative of a non-null non-detection zone.
- Islanding detection times for the wind park in this study employing Type 4 WEC were all under 1 second. The islanding risk for this topology was deemed negligible.
- The use of a properly adjusted reverse reactive power relay enabled elimination of all non-detection zones for the Type 3 wind energy converter.

Lessons Learned

The primary lessons learned are as follows:

- Distance protection is difficult to apply to distribution networks with distributed generation because of the need to account for laterals and load effects.
- As expected, voltage regulation tended to favor somewhat longer islanding detection times. However, when the inertia response function was implemented, the detection times were generally shorter.

Recommendations

Researchers made the following recommendations to Hydro-Québec Distribution upon completion of this study.

- Line protection of large distributed generation installations employing power electronics should be complemented with voltage controlled overcurrent protection. The overcurrent protection should be configured to the nominal current of a single generator, with voltage settings equivalent to those used in the undervoltage protection. While many of the faults are covered by the anti-islanding protection relays, the inclusion of this approach provides some redundancy to the line protection method.
- It is suggested to employ the reverse reactive power relays as a back-up anti-islanding protection, with an appropriately chosen delay. The actual setting of the relay requires knowledge of the maximum reactive power injection of the distributed generation installation, which likely requires a load flow simulation that includes modeling of the voltage control.

Unresolved Questions

This analysis is an exhaustive parametric study, based on relatively complicated modeling techniques. While interesting, these are hardly tools that are readily available to distribution system planners, and most planners do not have the time to spend on a study this detailed. As a result, distribution planning tools and the skills required by engineers to model and evaluate a distributed generation installation such as a wind farm must continue to be developed further.

For the full case study, search www.epri.com for product number 3002004503.

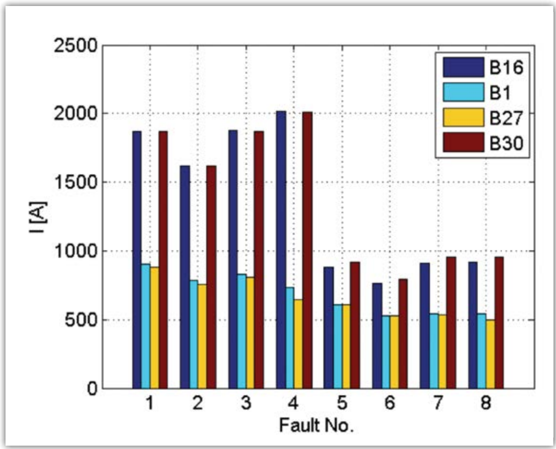


Figure 2 – Magnitude of fault currents

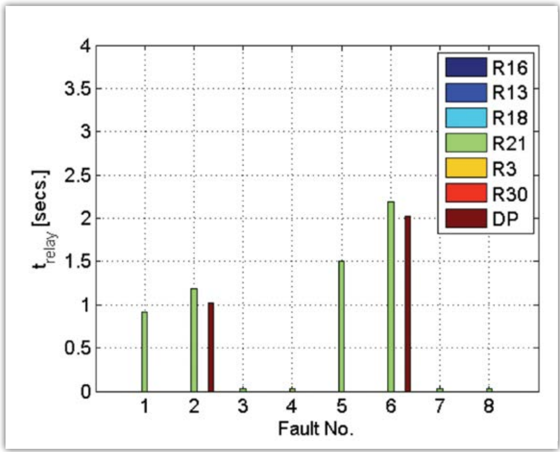


Figure 3A – Trip times associated with devices

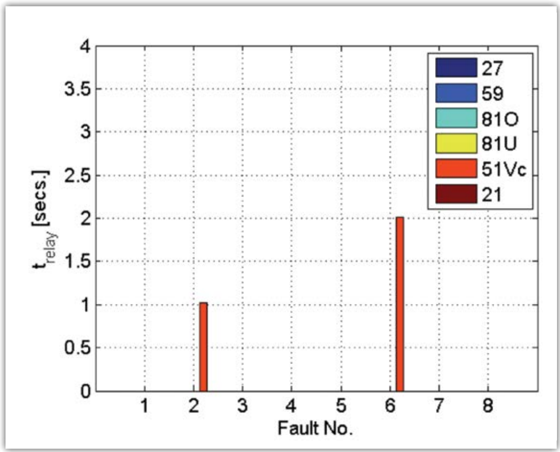


Figure 3B – Trip times for interconnection relays

Hydro-Québec

The undesirable effect of in-rush current during energization of a wind farm can be mitigated with passive approaches, specifically by installing series resistance or inductance as well as by controlled switching technology.

Evaluation of Solutions for Limiting Transformer In-rush Currents of a Distribution Connected Wind Park at Hydro-Québec

Integration of wind parks into distribution networks, like any large loads, may lead to power quality problems. A key power quality consideration occurs when a wind farm and its interconnection transformer(s) are energized following an outage. Most standards permit a wind farm to reconnect to the grid after the voltage at the point of common coupling has returned to within the acceptable range for at least a period of 5 minutes. As a result of this requirement, the in-rush current of the wind farm is not coincident with the energization of all other load transformers.

The energization of the wind park may result in two separate issues: the resulting in-rush current may exceed the pick-up current of protective equipment relays and/or the associated voltage drop may exceed the thresholds specified in the distribution codes. As a result, mitigation strategies may be required based on the wind farm transformer capacity and its location with respect to the substation. This study considers the testing of three such mitigation approaches using actual transformers and the developed solutions.

Objectives

The goals of the project include the following:

- Identify the most promising transformer in-rush current mitigation solutions for evaluation.
- Develop standard distribution apparatus prototypes for mitigation solutions to be tested on the distribution test system.
- Evaluate each of the most promising mitigation solutions through detailed testing.

The Test

Three methods for mitigating the impacts associated with transformer in-rush current of a wind farm following its energization were selected for testing. These were series resistance, series inductance, and a controlled switching relay, which were developed and constructed for testing on Hydro-Quebec's distribution test system. Figure 1 shows the cumulative probability distribution function for the observed in-rush current associated with each approach.

Results

Controlled switching achieved the best performance and required the least amount of space of the options evaluated, although the costs of such a system may present a barrier with widespread deployment. While the performance of controlled switching was superior, the maximum in-rush current was brought to within acceptable values by choosing appropriate impedances for the series impedance approach, which is lower cost.

The analysis of the tests showed:

- Each solution was able to reduce the maximum observed in-rush current but the controlled switching approach nearly eliminated any and all transients associated with energization.
- Each of the solutions required additional equipment, implying additional costs that include both engineering and capital costs. Such additional costs were highest in the case of controlled switching, although due to the novelty associated with its use in distribution, there is a potential for cost reductions, possibly bringing it in line with or lower than its passive approach counterparts.
- The maintenance of a single wind energy converter (WEC) is an additional scenario that may cause power quality problems when the wind farm is connected to a particularly weak system. The implication is that mitigation solutions may need to be applied at each WEC rather than the point of common coupling.

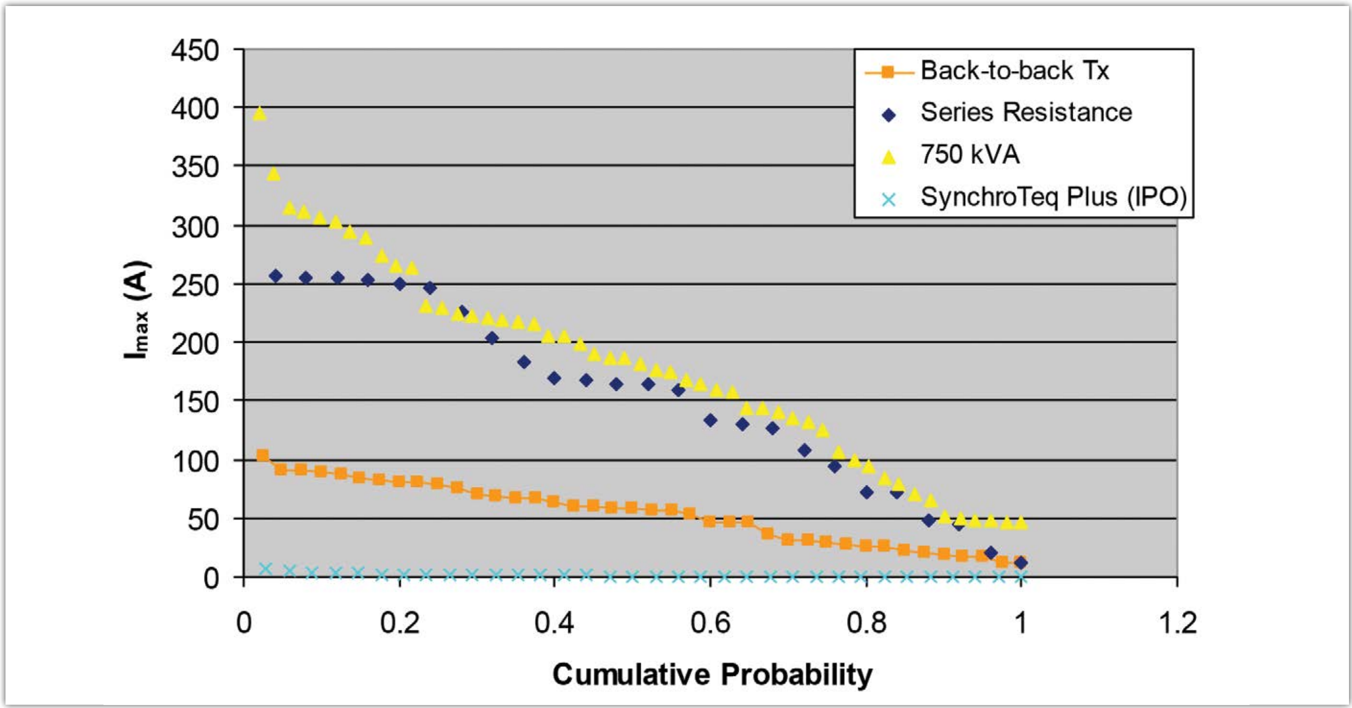


Figure 1 – Cumulative probability distribution function for observed in-rush current associated with the tested solutions

Lessons Learned

- Passive approaches to transformer in-rush current mitigation can be quite effective in reducing the maximum in-rush current. The relationship is exponential, in that relatively small impedance can translate to a sizable reduction.
- The controlled switching approach eliminated almost all of the in-rush current but delays were encountered in adapting the switching relay to the distribution apparatus.
- Proper calibration of the switching relay is necessary to achieve satisfactory performance from the controlled switching technology.
- Depending on the short-circuit ratio at the point of interconnection, a single turbine may even cause undesirable effects during energization and may require one of the mitigation solutions at each WEC in the wind park.

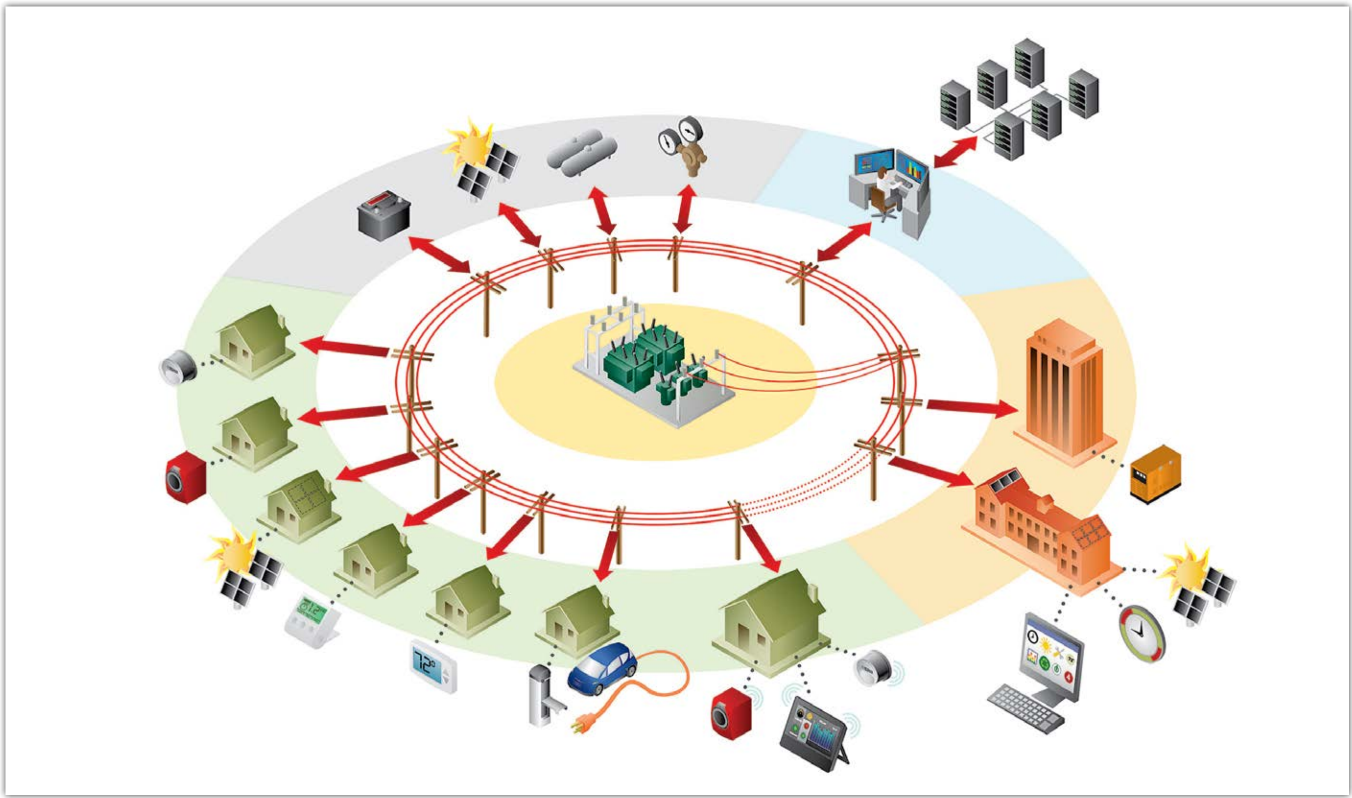
Unresolved Questions

Below are the unresolved questions that will need to be explored with these approaches:

- How does the impact vary depending on the strength of the system at the point of interconnection?
- Will costs for controlled switching come down significantly? What are the implications of such a technology for training and maintenance?
- How does the impedance of the wind farm collector system impact the remanent flux at each transformer and consequently the performance of the controlled switching approach?

For the full case study, search www.epri.com for product number 3002004502.

Kansas City Power & Light



> *Opting-in to receive a free device or information service does not, in itself, translate into customer engagement.*

The Kansas City Power & Light (KCP&L) SmartGrid Demonstration is creating a complete, end-to-end smart grid that features advanced metering, distributed generation, an enhanced distribution network, and automated control. Customer services enabled by smart meters to influence end-use behavior are also part of the demonstration, including time-of-use prices, and testing of technologies placed in homes.

Customer Acceptance and Technology Adoption

KCP&L intends to change the way the utility communicates energy use and cost information to residential customers, migrating from the once-a-month bill to more frequent contact through "MySmart Products." These products, enabled by the data collection and communication capabilities of advanced metering infrastructure (AMI), provide information on home electricity use, rates, and energy management, as well as estimates of upcoming bills.

This case study deals with 2011 research on customer acceptance of two products, an in-home display unit (MySmart Display, which is Tendril's Insite brand) and a web portal (MySmart Portal, which is Tendril's Energize).

MySmartPortal

MySmart Display

A unique feature of the KCP&L demonstration is a focus on urban revitalization. The target area is the urban core of Kansas City in areas dubbed The Green Zone and The Blue Zone. The Green Zone is a 150-block area with customers that suffer from high unemployment, low income, and inefficient homes. The Blue Zone is a surrounding area where demographics are more representative of city as a whole. All customers recruited are among the 10,000 mass-market customers in the demonstration area who received a smart meter.

Project Objectives

- Test effectiveness of various methods of enrolling customers.
- Measure acceptance of in-home displays.
- Measure acceptance of a web portal that provides energy information.
- Test and commission smart meters, in-home displays, the web portal and communications systems to ensure that energy consumption and cost information is available and accurately presented.

Results

Recruitment was based on an opt-in method, with customers having to enroll to receive the in-home display or access to the web portal. Methods to engage customers began with an awareness campaign with 10 "touches," including billboards, door-to-door visits with a welcome kit the day the smart meters were installed, direct mail announcements and mail-in cards, presentations at community and KCP&L-sponsored events, email messages, online applications and other outreach activities.

The project also entailed quantitative and qualitative market research about customers. A telephone survey of 187 customers was conducted as well as four focus groups. Results included:

- Customers expect an average savings of 23% by using new smart grid tools such as in-home displays.
- Saving money is the number 1 issue according to customers in both The Green Zone and The Blue Zone.
- In The Green Zone the number 2 issue is control.
- In The Blue Zone the number 2 issue is the environment.

Overall, customer recruitment strategies and enrollment did not always translate into customer engagement and acceptance of technologies:

- Acceptance of information-delivery products has reached half of the project goals within one year of the 2-3 year project span. Unique log-ins to the web portal totaled 1,066 out of a goal of 2,660; about 1,000 in-home displays have been provisioned compared to the goal of 1,600.
- During deployment of the in-home displays, more than 300 of the devices did not work; however, no customers with non-functioning displays contacted KCP&L, indicating lack of use and understanding of the device. Likewise, during a five-day malfunction of the web portal, customers made no queries or complaints.

Results of technology field tests included:

- Updates to the Landys & Gyr advanced meters, which were selected in the very early stages of the demonstration, were required to enable rate data and other cost information to be downloaded to the meters.
- Because of high concentration of displays in one area, network performance was reduced, and the range of Zigbee signals prevented use of the in-home displays in multi-story buildings exceeding three stories.
- Software design sometimes missed the mark in meeting utility use requirements; for example, the home energy display lost all energy use data at the time of a meter swap, which is a periodic occurrence.

Lessons Learned

- Utilities and vendors must work closely together so that hardware and software meet utility use requirements.
- A high concentration of network traffic in a close geographic area can compromise meter performance.
- "Door knock" enrollment resulted in high in-home display adoption rates (95%) among customer who were home.
- Obtaining customer email addresses is critical to marketing of Internet services. E-mails had a high response rate and a very low cost of less than a penny per enrollee (0.06 cents).

Overall, KCP&L believes that simply opting in to receive a free device or information service does not translate into customer engagement and use of information-delivery technologies. Measurement and verification of customer engagement, technology adoption, and use is planned for the remaining demonstration period, and will include tests of additional products and treatments, specifically time-of-use rates, a home area network, and programmable communicating thermostats.

For the full case study, search www.epri.com for product number 1026444.

Kansas City Power & Light

> *Direct contact at the time of smart meter installations—as well as a combination of marketing via email, direct mail, and community events or demonstrations–yields the best results with hard-to-reach customers.*

Customer Engagement for Multiple Smart Grid Products and Treatments

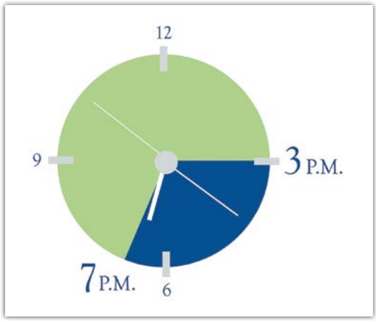
This case study brief addresses customer engagement efforts for the KCP&L SmartGrid project. Specifically, it deals with methods to educate customers and encourage adoption of treatments such as time-of-use rates. It also updates previous research on customer use of in-home displays, which was covered in EPRI's 2012 *Case Study on Customer Acceptance and Technology Adoption: Kansas City Power & Light*, Product ID 1026444.

The customers targeted in KCP&L's SmartGrid project were primarily within an underserved, low-income portion of KCP&L's service territory in the urban core of Kansas City, Missouri, an area designated as the "Green Impact Zone." As part of KCP&L's SmartGrid Demonstration project, a selection of no-cost "MySmart" tools and products, designed to help residential customers manage energy usage and, as a result, potentially save money on their monthly bills, was offered to target zone customers.

More than 9,000 customers in the target zone who received SmartMeters during the KCP&L Smart Grid Demonstration project were potentially eligible to use/adopt various products and rates. A range of products/rates were offered:

- MySmart Portal: A personalized website to help customers understand how they use electricity.
- MySmart Display: A hand-held, in-home electronic device that presented electricity use and cost information directly from customers meters on easy-to-understand screens.

- MySmart Thermostat: For homes with central air conditioning, this programmable communicating thermostat could be programmed to automatically set temperatures based on the season, time of day, and customers' schedules.
- MySmart Network: A home area network (HAN) that allowed appliances, a thermostat, and other end-use electrical devices to communicate with one another in the home. In addition to energy information, the MySmart Network enabled customers to set targets for monthly usage through the integrated energy management portal. All home components could be managed through the portal.
- Time-of-Use Rates: Rates based on the time of day of electricity usage and the cost of supplying electricity at that time were offered to encourage customers to save money by shifting consumption to off-peak periods.



Approach

Both direct marketing and public education were done to engage customers. Major components of the education effort included the following:

- *Hyper-local presence*. Early in the project, KCP&L opened a SmartGrid Office within the targeted zone where customers could directly interact with KCP&L employees to ask questions, get support and generally learn about the project. KCP&L also leveraged its employees who lived and worked in the targeted zone to be "SmartGrid Ambassadors" to help spread the word.

	MySmart Portal	MySmart Display	Time-of-Use Rates	MySmart Thermostat	MySmart Home
Project goal	2,660	1,600	264	1,600	400
Number of customers who received the treatment	2,040	1,231	124	104	61

- *Project Living Proof.* KCP&L was the lead sponsor of the Metropolitan Energy Center's Project Living Proof (PLP). The PLP restored a modest home, in the SmartGrid zone, to exhibit how to make a century-old home more energy efficient. Visitors to the home could see first-hand the new MySmart tools and products.

A special "MySmart" brand for the SmartGrid project was developed to help market the treatments. One of the unique marketing tactics included a web-key to promote the use of the energy management portal. A post-card type flyer included a punch-out USB device that would open the SmartGrid portal webpage directly on a customer's PC. Direct mailings were also used, which produced good results, likely because KCP&L had not engaged its customers using direct mail for product enrollment prior to the SmartGrid project. Finally, the best participation and responses came from KCP&L's customers through email communications.

Results

KCP&L had more than 3,000 of the 9,000+ potentially-eligible residential customers participate in its SmartGrid program. This represents a 30% participation rate which is above the norm for KCP&L's energy efficiency programs. The table at the top of the page shows the number of people who opted into (and stayed in) each treatment.

Detailed results on customer engagement and participation will be available in a case study slated for publication by the end of 2014. Early results show that:

- Of the approximately 600 people who were still using their in-home display at the end of the project, 50% of them liked the display and found it useful.
- KCP&L offered a TOU rate for the first time in 2012 (and continued to offer it through 2014). More than 80% of the customers who selected the TOU rate saved money on their summer bills. The first year, early adopters saw an average of $31 savings in monthly bills (the average summer bill in the area is $115). As enrollment continued the following two years, the average savings dropped to $16 per bill.

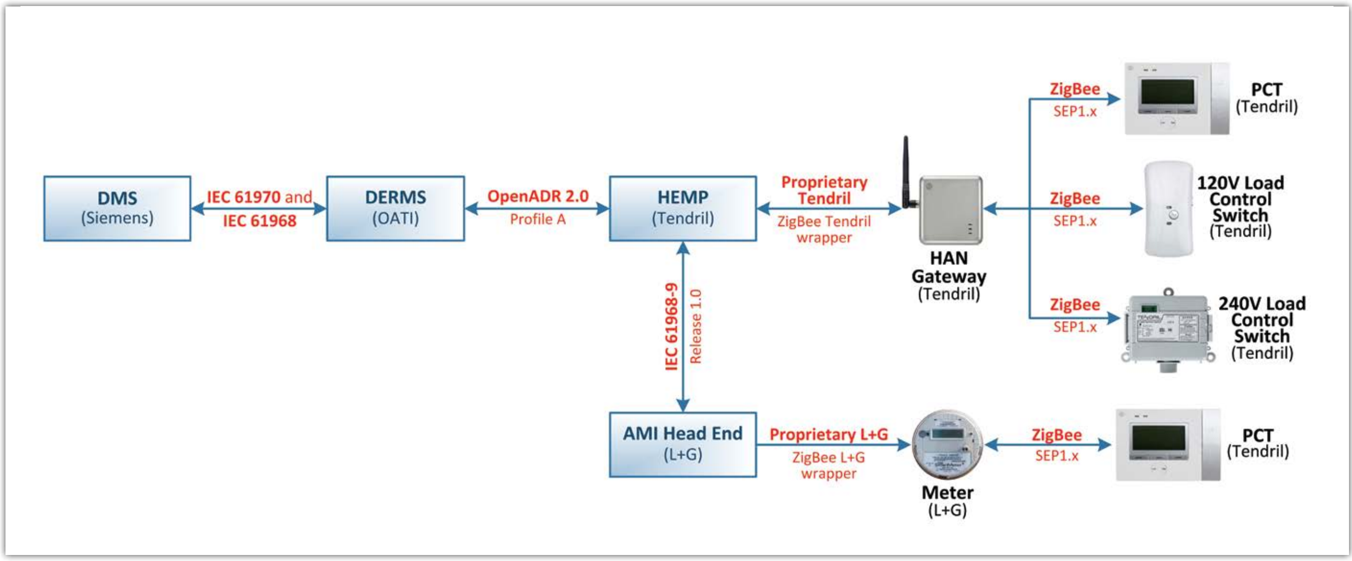
Lessons Learned

KCP&L implemented strategies designed specifically to test and demonstrate means of engaging customers who are typically hard to reach and to help revitalize an urban core area. Experience was gained and lessons learned across a wide range of areas.

- To implement the strategy of hiring local labor, a robust training program is important. For example, the SmartGrid Ambassadors who lived in the target zone initially lacked adequate product knowledge.
- When KCP&L held its own events, attendance was poor. Engagement was best when KCP&L attended or co-sponsored community events and offered an opportunity for product enrollment at those events. This type of grassroots outreach was unique, at the time, for product enrollment.
- Analyzing market potential is crucial. Had KCP&L understood that of the 9,000 customers in the Green Impact Zone, fewer than 4,000 had central air conditioners, the target for thermostat adoption would have been set lower than 2,000.
- Offer customers all tools/treatments at the time of meter installation. High enrollment was achieved with this tactic.
- Be sure the tools given to customers work properly. The in-home display product did not function due to meter technology issues and display constraints. KCP&L found many customers discarded the display because it did not work immediately, though it would have worked a short time later.

For the full case study to be published at the end of 2014, search www.epri.com for product number 3002004632.

Kansas City Power & Light



Although industry standards are beneficial, the creation of a certification body as well as specific standard application profiles is critical in expediting the development of demand response interfaces between multiple vendors.

Residential Demand Response Standards and Interoperability

KCP&L is advancing demand response (DR) messaging standards within its SmartGrid Demonstration Project. By leveraging DR interoperability standards, KCP&L is testing and demonstrating residential DR event management using its demand response/ distributed energy resource management system (DERMS), distribution management system (DMS), customer-oriented home energy management portal (HEMP), meter data management (MDM) system, advanced metering infrastructure (AMI), and home area network (HAN) devices.

Demand Response Flows

In the KCP&L system, the DMS calls upon the DERMS when assistance is needed with a current or projected future overload. The DMS will first try to solve the issue using its own resources: feeder load transfer or conservation voltage reduction. If these methods do not completely address the overload, then the DMS will call upon the DERMS for demand response.

Once the operator selects the DR solution to apply to the situation, the DERMS schedules the DR event. The DERMS does not communicate directly to the end devices, but instead sends DR messages to "control authorities," including the HEMP. The control authorities send the appropriate DR messages to the end devices to direct their participation in the scheduled event.

Downstream of the HEMP, there are two paths to the residential end devices:

1) Through the AMI head-end to the smart meter and then to the stand alone programmable communicating thermostat (PCT).

2) To a home area network via the customer's broadband Internet connection and then through a customer gateway to the PCT or a load control switch.

Post-event participation information is sent back to the DERMS from the HEMP.

Development and Testing

KCP&L applied the EPRI IntelliGrid methodology to develop use cases that defined the processes, integration, and data flows needed to schedule and implement DR events in response to localized distribution grid congestion issues.

KCP&L and its contractors and vendors worked on technical specifications for interfaces to develop standards-based messages that would be used to exchange agreed-upon information.

KCP&L selected several emerging smart grid standards necessary to implement the DR event messaging between systems. These standards include: OpenADR 2.0 between DERMS and HEMP; IEC 61968 between HEMP, MDM, and AMI systems; IEC 61970 and IEC 61968 between DERMS and DMS; and ZigBee SEP to devices within the HAN.

Steps taken to build the interfaces for residential DR included:

1) Design and testing of the DMS/DERMS interface, using IEC 61970 CIM15 and IEC 61968 CIM11. This was a completely new interface, and it required extensions from the standards and considerable coordination between vendors Siemens and Open Access Technology International (OATI).

2) Design and testing of the DERMS/HEMP interface, using OpenADR. OATI and HEMP vendor Tendril used OpenADR 2.0, profile A, for this interface. Profile A was still in development stages, so KCP&L directed the vendor to design around a particular working draft of the standard.

3) Design and testing of the HEMP/AMI head-end interface, using IEC 61968 between systems and ZigBee SEP to HAN devices. AMI vendor Landis+Gyr and HEMP vendor Tendril used IEC 61968-9 for this interface. For the interfaces between HEMP and the HAN devices and between the AMI smart meters and the HAN devices, ZigBee SEP 2.0 was not yet available, so SEP 1.x was used.

4) Design and testing of the KCP&L enterprise service bus (ESB) and object identifiers. For all system-to-system flows, KCP&L instructed vendor partners to interface through its ESB. This was done to help ensure adherence to standards, as it prevents any one-off, point-to-point interfaces. It also allows for any necessary data lookups or translations that might not be available from one system but that are available from another.

Results and Lessons Learned

The following are key findings and lessons learned:

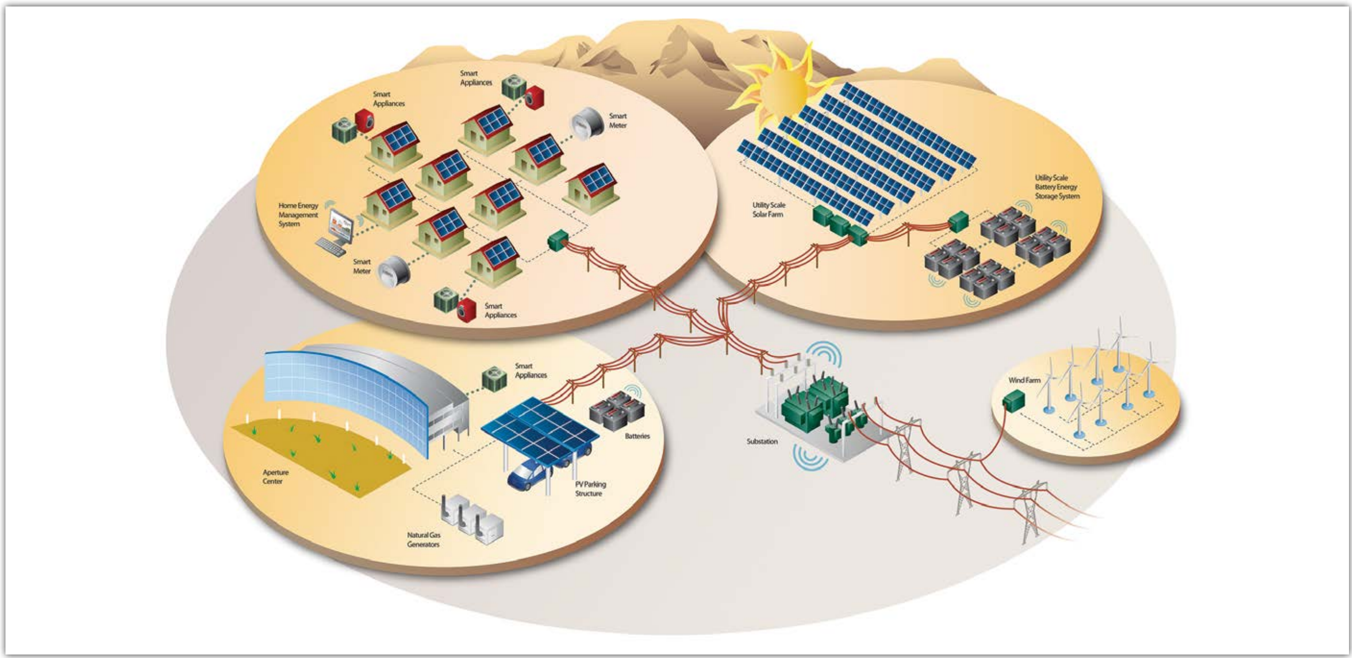
- Standards assist in the development of demand response interfaces, but application profiles within these standards are critical to remove extensive vendor interpretation. Profiles greatly expedite the multi-vendor interface development process.
- A message bus is still needed for translating data between application profiles or versions of a particular standard, and to help manage integration if interpretations of the same profile differ between vendors.
- While working on the DMS/DERMS interface, even though the two vendors agreed upon a common version of the CIM data model, there were still adjustments required for each model propagation. Additionally, IEC 61968 required extensions in order to support the exchange of necessary information.
- Because the standards creation process can be very slow, KCP&L was forced to decide between adopting an older version of a standard and delaying the interface development process. For example, since ZigBee SEP 2.0 was not completed during the product development and deployment cycles, all functionality was limited to what was available in SEP 1.x. Certain functionalities that exist in legacy KCP&L thermostat programs are not supported by SEP 1.x, such as HVAC cycling, so they could not be implemented as a part of this project.
- Several back-end systems use meter ID or customer account ID as the unique identifiers, but as meters are replaced and customers move in and out, this becomes problematic. As a result, KCP&L used Service Point ID (SPID) as the unique identifier where possible. Since this wasn't feasible to use across all systems, KCP&L used the ESB for transformation between varying unique identifiers from system to system. This issue might not be a problem in the future, as 61968-9 Release 2.0 accommodates SPID as the unique identifier.
- With the complexity of end-to-end flows crossing multiple systems, it became critical to have good information about whether each interface was up and running properly. After several communication failures between the DMS and the DERMS, the team added a "heartbeat" message for the status of the interface. This message gives KCP&L system operators an alarm on the DMS if the communications path between the two systems is severed for any reason.

Next Steps

The pilot is being conducted in 2014, and the role of the DERMS will be evaluated for future enterprise deployment.

For the full case study, to be available by the end of 2014, search www.epri.com for product number 3002004639.

Public Service of New Mexico



> *At scale—or combined with other storage resources within the system—energy storage is able to use intermittent renewable generation and create a firm, dispatchable resource.*

The Public Service of New Mexico (PNM) Smart Grid Demonstration Project is developing and deploying advanced distribution control and communication infrastructure with the goal of optimizing the system benefits of renewable resources. Activities include deployment and testing of a 500 kW PV system with storage, and evaluation of customer-based demand response opportunities.

Use of Storage for Simultaneous Voltage Smoothing and Peak Shifting, 2013 Update

PNM designed a system that uses energy stored in batteries to simultaneously mitigate voltage fluctuations through battery smoothing and manage peak demand through battery shifting. This case study presents an update of results of tests of these functions conducted in 2012 and 2013.

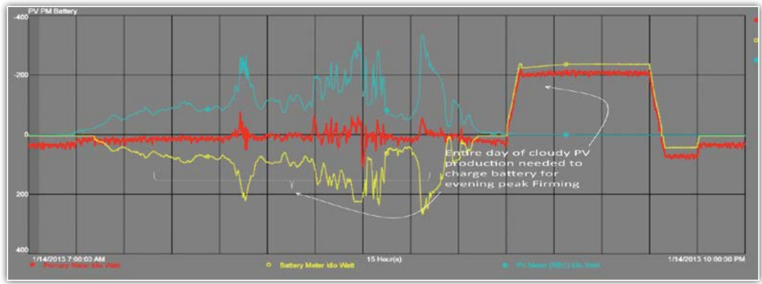
Both smoothing and shifting are critical for a distribution system with a high penetration of photovoltaic generation. Smoothing PV output is important since PV ramp rates (the speed at which power output increases or decreases) can be very fast, going from full power output to zero in just a few seconds. This can cause voltage variation on an associated feeder that is great enough to affect customer service voltage.

Ensuring that a certain amount of energy is available to meet system peak is also important. This includes "firming," which is the ability to guarantee constant power output to the electricity market during a certain period of time, and "peak shaving," which is the ability to limit the load on a given feeder served by a substation.

Major System Components

The PV plus storage project includes a 500 kW PV system installation with 2,158 Schott solar panels. The energy storage system is comprised of Ecoult/ East Penn Manufacturing Advanced Lead Acid batteries with an energy rating of 1 MWh for shifting, and UltraBattery™ advanced lead acid battery units with a power rating of 500 kW for smoothing. The UltraBattery is built for quick response, operating at a high discharge and charge rate.

The PV plus storage is located on PNM's Studio Substation distribution feeder, which serves residential and commercial/ industrial customers in an area near Albuquerque, New Mexico.



Simultaneous smoothing and shifting during extremely variable power period due to overcast conditions, January 2013.
Key: — *Total system output* — *Battery output* — *Solar output*

Methodology

The project entails gathering and modeling feeder load data, modeling peak load, modeling predictions of PV energy output, and developing algorithms for control and optimization of both smoothing and shifting. Shifting applications include firming, peak shaving, and arbitrage. The system relies on a robust, cyber-secure data acquisition and control system that collects 220 points every second.

The algorithm used to smooth PV intermittency was developed by Sandia National Laboratory. The smoothing algorithm resides within the battery controller and was evaluated at four different battery capacities (100%, 80%, 60% and 40%).

The shifting control strategy is based on sending a utility-based command from the advanced calculation engine (ACE) to distributed resources. ACE can pull power market prices, data from SCADA, and weather data from the National Oceanic and Atmospheric Administration (NOAA).

To shave peak, PNM and the University of New Mexico are predicting the next day's peak load by correlating the maximum, minimum, and mean temperature and associated recent-day, historic feeder loads. This is combined with PV-output prediction, which is an analysis of predictive clear and cloudy day data to help provide better forecasts. This is being done by correlating data on different intermittences and different types of cloud-cover forecast percentages.

Results

Algorithms have successfully accomplished simultaneous smoothing and shifting, and have also enabled firming and peak shaving. Furthermore, the algorithms were able to take extremely variable power that would be very difficult to regulate, and created a defined output in both amplitude and duration during the system peak.

The figure displays a cloudy day in January 2013. With the input gain set at 0.8, effectively 80% of the smoothing battery capacity was used. The storage system was able to take available energy produced by PV and dispatch it to provide a firm block of energy to align with evening peak load. The peak shaving algorithm has also been optimized and refined and has enabled PNM to meet a target 15% reduction in peak summer load on the associated feeder.

Lessons Learned

- Intermittent PV generation can be stored locally in the energy storage system with little output to the grid over a day's production. This energy can then be dispatched with a defined time duration and output level (firm energy production), or with a varying production that offsets a predicted feeder peak (peak shaving). Although this specific project is small enough that the firm energy dispatch may not have a direct effect on today's total resource stack at PNM, the results show that at scale—or combined with other energy storage resources within the system--energy storage is able to take highly intermittent renewable generation and create a firm, dispatchable resource.
- Developing the shifting algorithm has proven challenging due to the need for a power prediction engine that uses a next day, percentage-of-cloud-cover prediction. Despite successfully demonstrating the capability of weather predictions in the project, day-ahead weather forecasts are not yet sufficiently dependable or accurate.

Efforts to further optimize the shifting and smoothing algorithms as well as improve cloud-cover prediction are underway.

For the full, publicly available case study, search www.epri.com for product number 1026445.

Public Service of New Mexico

Coordinated control of a customer-owned gas-engine generator and fuel cell with a utility-owned battery reduced the battery capacity required for PV smoothing.

PV Smoothing Using Coordinated Control of a Battery and Gas Generator & Fuel Cell

PNM deployed a photovoltaic (PV) plus battery storage system to simultaneously mitigate voltage fluctuations through battery smoothing and manage peak demand through using the energy stored in the batteries.

The PV plus storage project includes a 500 kW PV system installation with energy storage in batteries with an energy rating of 1 MWh for shifting, and units with a power rating of 500 kW for smoothing. The publicly available EPRI report *A Case Study on the Demonstration of Storage for Simultaneous Voltage Smoothing and Peak Shifting*, product ID 1026445, provides detail on the PNM PV plus storage project.

PNM is also part of a demonstration of a commercial building microgrid designed and built by the Japanese government's New Energy and Industrial Development Organization (NEDO). This building with microgrid, the Aperture Center, is located about 1.7 miles (~2 kilometers) from the PNM PV plus storage system, or about 2.5 circuit miles. The NEDO building microgrid includes a 240 kW gas engine, 80 kW fuel cell, 50kW photovoltaic array, as well as 50 kW of battery storage, thermal storage, and a building energy management system.

This case study covers a test of the coordinated control of PV smoothing for the PNM system, using the PNM batteries and the NEDO gas-engine generator (GE) and fuel cell.

Project Objective

The overall objective of this project was coordinated control of the PNM battery and the NEDO Aperture Center gas-engine generator to reduce the battery capacity required for PV smoothing while maintaining grid power quality.

Approach/Methodology

Simulations were performed to determine potential reduction in battery operation (state of charge or SOC range) when the battery is paired with a gas-engine generator.

Researchers evaluated coordinated versus uncoordinated control algorithms compared to the baseline system with only a battery. In the coordinated control test, signals were passed between the building microgrid and the PNM back office—and ultimately to the battery control system—using a PI to PI connection. Figure 1 illustrates coordinated control; Figure 2 shows uncoordinated control.

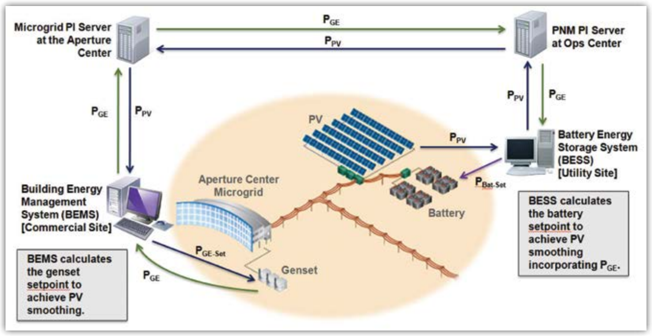


Figure 1 – Coordinated, distributed PV smoothing

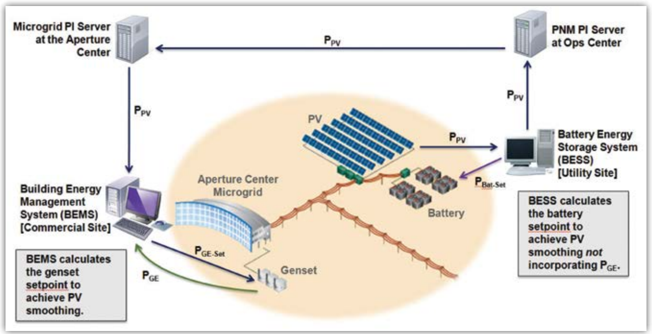


Figure 2 – Uncoordinated, distributed PV smoothing

(Figure 1 and Figure 2 are courtesy of Sandia National Laboratories.)

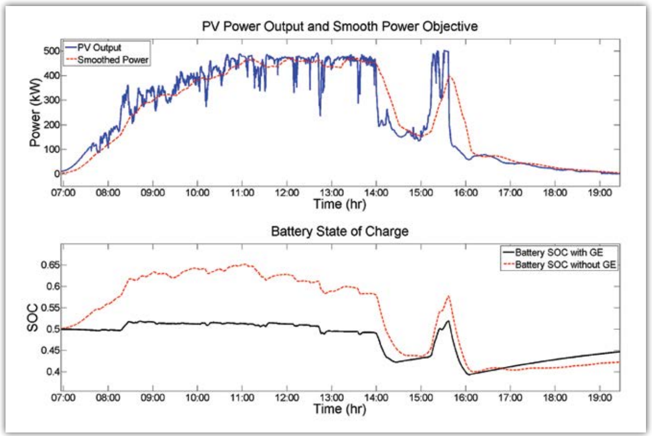


Figure 3 – Simulation results

Tests of the smoothing algorithms included two test cases:

1) Controlled intermittency – A portion of the PV system was turned off during a day without clouds to achieve highly repeatable, artificial PV variability. This was done to understand response with a known drop in PV output.

2) A cloudy day - a day with variable irradiance.

Results

Simulations showed a reduction in battery operation (state of charge or SOC) when the battery is paired with a gas-engine-generator (GE), per Figure 3

The actual tests showed that the state of charge dropped more than the simulations predicted, resulting in more duty on the battery than expected. The coordinated control showed less duty on the battery system than uncoordinated control (Figure 4).

The key results were:

- The team successfully demonstrated a coordinated, distributed controller that reduced the variability of renewable energy resources with less battery energy throughput.
- In certain high variability situations, the coordinated control used more battery state of charge range than simulations predicted.

Lessons Learned and Conclusions

- Changes needed to be made to the control algorithm because the original algorithm was designed for PV, not a gas generator. Measuring the changes in the gas engine was initially a problem, because the gas engine has both positive and negative ramps with respect to the output from which the gas engine was set to run in steady state, and the algorithm was not designed to receive negative values. When the gas-engine generator was first operated, the battery system was started before the gas generator. Because the gas engine was producing a large negative value as compared to the steady state (essentially zero watts minus the planned steady state value), the battery tried to charge very rapidly in response to a large negative output, and this resulted in the battery system shutting down because of error. PNM had to recode input limits in the smoothing controller to ensure it could receive both positive and negative values.
- The PI system worked adequately for this test, but a question remains on whether the PI system will be satisfactory for grid power quality needs.
- Although this project was successful, ultimately, connecting one building's generation with a smoothing battery using point-to-point control is impractical. If there is more than one distributed energy resource (DER) on the system, a common point of connection is needed (that is, there could be too many one-to-one connections needed, that could make for a complicated control architecture). If there are multiple DER, a distributed energy resource management system (DERMS) should be in place as well as a microgrid controller that handles islanding. With a DERMS acting as a "conductor of an orchestra," multiple DER will not compete with each other.

For the full case study, scheduled to be completed by the end of 2014, search www.epri.com for product number 3002002257.

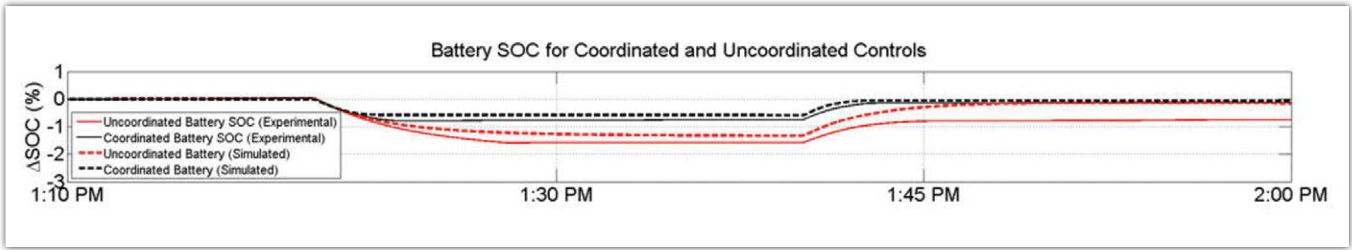
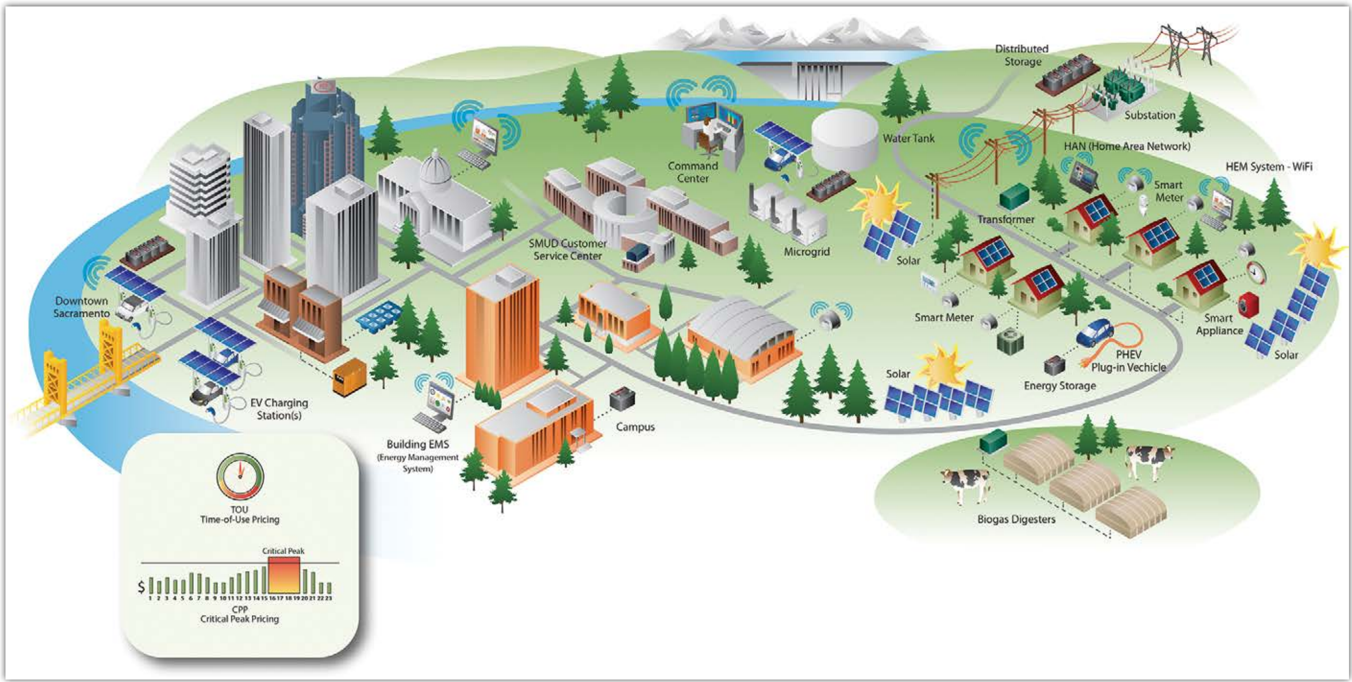


Figure 4

Sacramento Municipal Utility District



Volt-var optimization enabled efficient operation of the distribution system while conservation voltage reduction reduced peak demand by an average of 1.7%.

The Sacramento Municipal Utility District (SMUD) Smart Grid Demonstration Project, SmartSacramento®, is a collection of more than 40 individual projects focused on improving grid efficiency and resiliency, providing higher power quality and reliability, empowering customers, integrating distributed energy resources, enabling demand response, creating a platform for secure interoperable systems, and reducing the environmental footprint of the utility system.

Conservation Voltage Reduction and Volt-Var Optimization

In 2011, SMUD conducted tests to improve distribution system efficiency through a conservation voltage reduction (CVR) experiment and a test of new volt-var optimization software.

CVR is a reduction of voltage along the distribution feeder to help reduce electric power demand. By reducing the voltage by a few percentage points, but keeping voltage in the acceptable range (±5% of 120V), demand is reduced, and voltage is adequate to deal with voltage drops or sags. CVR is a well established means of shaving demand, but is being tested on specific SMUD feeders to better understand the performance of new, enabling technologies and to better predict potential demand savings.

Volt-var optimization (VVO) is a means of keeping voltage, and reactive power (measured as volt ampere reactive or var) at levels that minimize electricity losses. Advanced software incorporated into the smart grid management system provides better coordination and control of devices in the distribution system to achieve optimal volt-var management.

The Tests

SMUD's tests entailed the following system enhancements: the installation of new switched capacitor banks, addition of new capacitor controllers with two-way radio communications, implementation of the new VVO software (an enhancement to an existing system called Capcon), modification to the voltage settings and local override control for the load tap changer (LTC) controllers, and implementation of the CVR control capability with the existing Siemens SCADA system.

CVR was tested by SMUD on six feeders to determine energy savings as well as peak demand reduction. The test feeders are served from the Madison-Kenneth and Myrtle Date 69/12 kV substations.

In order to test both the CVR and VVO benefits, SMUD carefully designed tests so that there were days when only CVR or VVO was implemented, days when both were enforced, and days when neither was active. CVR tests were conducted at three different levels: at 1%, 2%, and 3% reductions in set point voltage in the load tap changer (LTC) on the power transformer.

Project Hypotheses

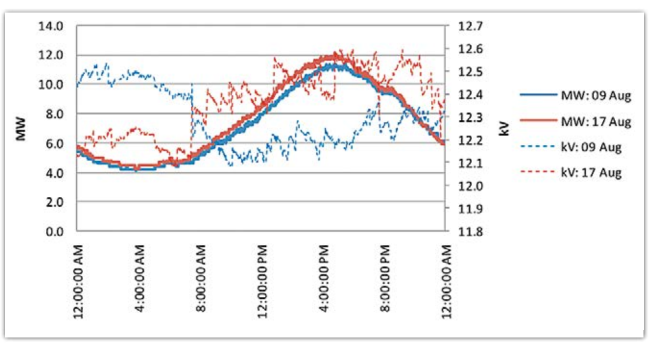
The following are the hypotheses for the CVR/VVO project:

- Capcon control logic can be modified to incorporate control of distribution line capacitor banks to maintain power factor to within an acceptable range.
- Control logic and communications can be used to control the voltage reduction level on the LTC controller from the distribution operations center.
- Demand is reduced and energy savings increased as the normal level of voltage is reduced by 1-3%.
- Proper reactive power management on a substation results in less system losses.

Results

On average, the approximate demand reduction for a 2% CVR test (2% voltage reduction) was 2.5% for the Myrtle-Date and 1% for the Madison-Kenneth substations. Additional tests are to be performed in 2012-13 to determine why the results were so different for the two test substations.

The plot below shows an example 2% CVR test on August 9th compared to the reference day of August 17th. The comparison of the dotted lines shows the marked reduction in voltage that resulted from the CVR implementation. The blue dashed line shows the voltage being reduced around 8:00am. The red dashed line shows the voltage returning to normal at the same time on the non-test day. The solid red and blue lines show the corresponding reduction in demand between the test day and the non-test day.



Myrtle-Date 2% CVR Example

One 3% CVR test showed an additional reduction of 350kW. This indicates a total demand reduction of about 5% for this single instance. Additional 3% CVR tests are planned for 2013 to confirm whether or not similar demand reductions are observed over numerous tests.

The VVO control logic was demonstrated and the changes in the control logic confirmed via measurement. The final control logic maintained overall power factor between 0.95 leading and unity on the low side of the substation transformer for both the Madison-Kenneth and Myrtle-Date substations.

The loss minimization from VVO is of a magnitude that was not discernible based on the measurement resolution available. However, simulations consistently showed small reductions in electricity losses in addition to management of the power factor.

Lessons Learned

- Researchers observed that the Carmichael 230kV voltage used for both Capcon and the VVO control logic generally indicated substantially lower than neighboring 230kV voltages. As a result, the VVO control logic often called for greater reactive compensation than would have been called for based on surrounding voltages. This greater reactive compensation resulted in a correspondingly greater leading power factor. As a result, SMUD modified the control logic to prevent the power factor from going beyond 0.97 leading.
- Testing of VVO on the Myrtle-Date circuits yielded reactive power being maintained within varying ranges as the control logic was altered during the test cycle. The sporadic inclusion of two distribution capacitor banks due to communication issues, and the switching of substation feeder capacitors that are 1,800 kvar (rather than the line capacitors that are 1,200 kvar), resulted in a wide range of reactive power demands.
- Volt-var optimization enables efficient operation of the distribution system and provides voltage support necessary to implement conservation voltage reduction.
- Additional testing amongst a larger pool of substations is required in order to determine predictability of the conservation voltage reduction control strategy.

For the full case study, search www.epri.com for product number 1026446.

Sacramento Municipal Utility District

Participants who opted for a TOU/CPP rate dropped 70% more load during peak events than did those on direct load control.

Residential Summer Solutions

The SMUD Summer Solutions project was conducted in the summers of 2011 and 2012 to test how different information and load control treatments affect energy savings and peak demand reduction. The work was done by contractor Herter Energy for SMUD, and involved a self-selected sample of more than 300 residential customers. The study investigated the effects of dynamic pricing, customer-programmed thermostat automation, utility-controlled thermostat automation, and various levels of real-time energy and cost information.

The Sample and the Treatments

In 2011, there were 265 study participants as well as a "recruit and delay" control group of 137. The control group members were allowed to fully participate in 2012, when there were 313 participants and no control group. All participants received a communicating thermostat that notified occupants of an impending event and enabled automation of air-conditioning response, either by the customer or by the utility.

Information Services

Participants were randomly assigned to three different information treatments:

1. Standard billing information, including SMUD's MyEnergyOnline web portal, which is available to all customers. Here, line and bar charts display historical household energy use data in monthly, daily, and hourly intervals.
2. Home level energy data was provided using a submeter on the home's main electricity supply line. The submeter transmitted real-time energy data for customer viewing at the thermostat or computer.
3. Appliance level data on HVAC systems, electric water heaters, electric dryers, pool pumps and customer-selected plug loads was provided via the thermostat and gateway-assisted computer portal. This data was provided in addition to the home-level data.

Rates

Participants could sign up for the standard rate or the Summer Solutions rate. The standard rate is a default, two-tiered rate with Tier 1 at 10.45¢/kWh and Tier 2 (when usage exceeds 700 kWh per billing cycle) at 18.59¢/kWh. The Summer Solutions rate (SS rate) was an experimental rate that combined SMUD's tiers with time-of-use and critical peak pricing (TOU/CPP). This rate had four different prices: 7.21¢/kWh during the Tier 1 off-peak period, 14.11¢/kWh during the Tier 2 off-peak period, 27¢/kWh during the weekday peak period from 4-7 pm, and 75¢/kWh during critical peak events, which were called from 4-7 pm 12 times each year.

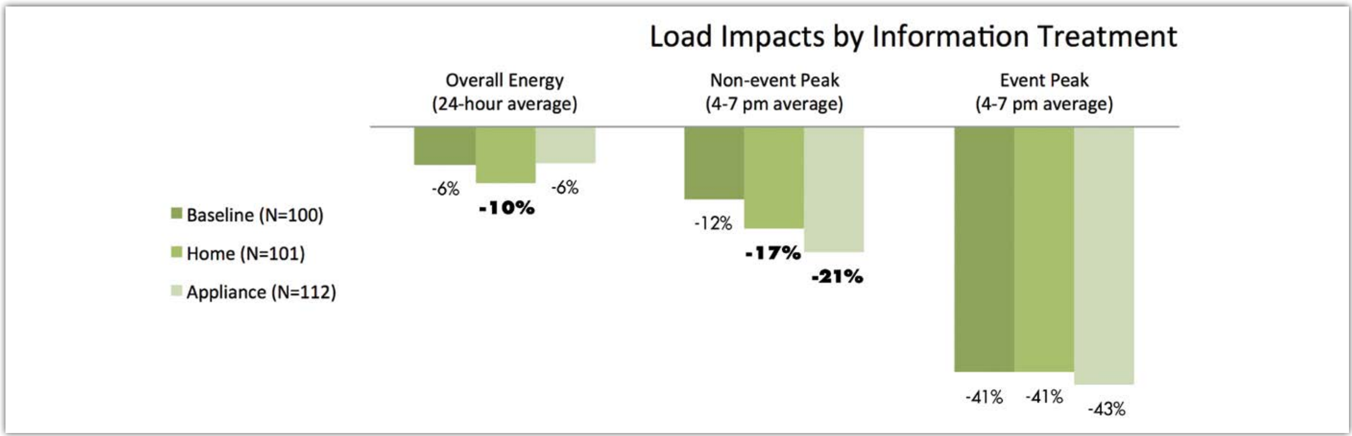


Figure 1 – Numbers in bold are significantly different from Baseline

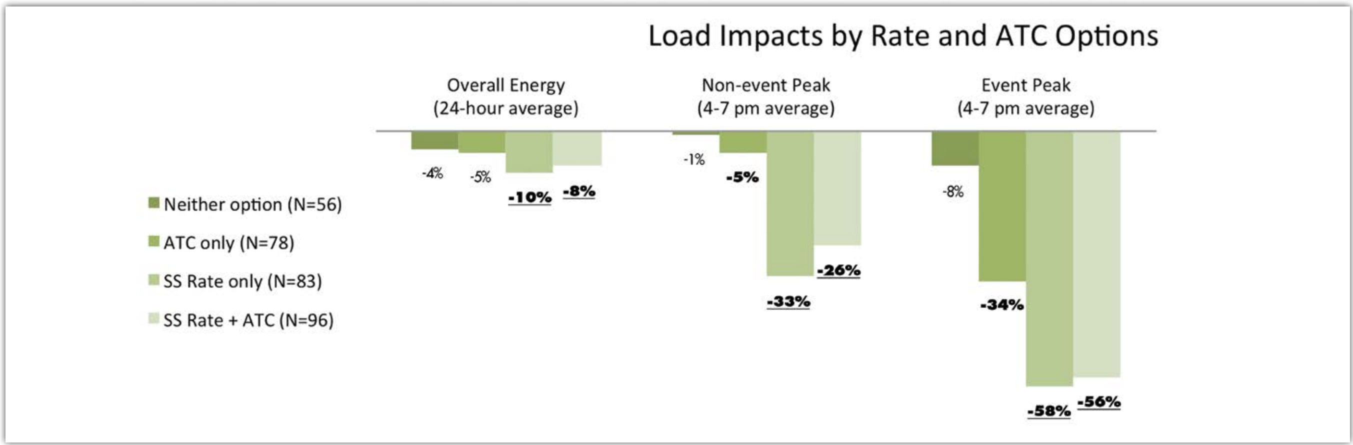


Figure 2 –Numbers in bold are significantly different from Baseline. Underlined numbers are significantly different from ATC. ATC = automated automatic thermostat temperature control; SS Rate = Summer Solutions Rate

Automated Load Control

Participants could select whether they wanted to control the automated event temperature settings on their thermostat or have the utility control it for them. The two options were:

1) Customer programmed temperature settings, which enabled customers to pre-program an automatic response to events, from 0 to +9 degrees, with overrides and modifications allowed at any time.
2) Utility controlled temperature settings, or Automatic Temperature Control (ATC), which increased temperature settings by 4 degrees during events and allowed one override per season. With this option, customers received a $4.00 per event incentive.

Results

Of participants offered both the TOU/CPP rate and the ATC options, 49% chose both, 25% chose the TOU/CPP rate only (no ATC), 13% chose the ATC option only (with the standard rate), and 13% chose neither option (standard rate with no ATC, i.e. information and event notification only).

Both home-level and appliance-level energy information resulted in greater peak demand savings on non-event weekdays, but had very little effect on event savings, as shown in Figure 1. Home information improved overall energy savings throughout the day, but this effect was not evident for participants that received appliance information in addition to home information. An analysis of loads for just the second-year participants, however, showed that home-level and appliance-level information resulted in similar overall savings throughout the day, implying a one-year learning curve for the customers that received the more detailed appliance-level data.

Those with the experimental TOU/CPP rate who controlled their own response to events exhibited a 10% overall energy savings, dropped 33% of their load during non-event weekday peak periods, and dropped 58% of their load during peak events – 70% more than those on direct load control alone – as shown in Figure 2. The results for those on the TOU/CPP rate with Automatic Temperature Control were nearly identical.

The higher peak savings for those on the TOU/CPP rate can be explained by the TOU peak price on non-event days, and by the price incentive to shift or reduce all loads, not just the air-conditioning load targeted by the direct load control ATC program. Higher overall savings for those on the TOU/CPP rate is likely a result of peak reduction measures that also contributed to overall energy savings, for example air-conditioning tune-ups or replacement.

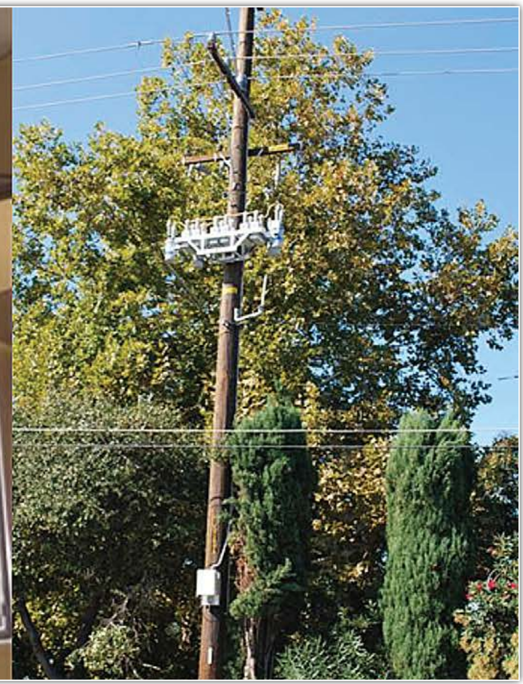
Lessons Learned/Recommendations:

This study led the research team to make the following recommendations:

- Offer a voluntary TOU/CPP rate for energy savings, daily weekday peak reduction, and occasional summer peak load reduction.
- Offer rebates or recommendations for user-friendly thermostats that can automate pre-cooling and peak load drop for TOU peak periods and/or CPP events. As an option, also consider thermostats that display the real-time electricity rate, event status, and/ or real-time energy data.
- Do not offer a financial incentive for direct load control where TOU/CPP is offered.
- Do not offer appliance level information at this point in time, because of its high cost, limited energy savings, and lower customer ratings.

For the full, publicly available case study, search www.epri.com for product number 3002002247.

Sacramento Municipal Utility District



Ordinary least squares (OLS) estimation methods provide similar CVR impact estimates to median regression, a "robust" estimation method.

2013 Analysis of Sacramento Municipal Utility District Conservation Voltage Reduction (CVR) Tests

In the summer of 2013, SMUD expanded its 2011-2012 CVR evaluation of 2 substations to include 14 substations during the June through September time period. The CVR testing used a random-day test pattern. On each test day, seven substations were selected at random to have a lower than normal voltage, while the voltage at remaining substations was set to normal.

Objective

The primary objective of the study was to develop a statistical (econometric) model of substation load, incorporating potential CVR impacts, and to use the model to estimate the impact of CVR on load and energy use at the tested substations. Even though only the substation data was used for this analysis, the methods utilized in this study could be applied at the feeder level or another large grouping of customers. The statistical model was designed so that the CVR results could be analyzed for two types of operational uses of CVR systems: a targeted load reduction approach during high-demand hours and continuous operation approach.

Project Hypotheses

The main hypotheses tested in this project were:

- Substations with similar customer makeup have the same CVR factor or CVRf (a CVR factor is the percent reduction in load obtained per percent of voltage reduction). For example, if load is reduced 2% from a voltage reduction of 3%, then the CVRf is 2%/3%, or .0.67.
- Selected regression models will produce similar results from CVR tests.
- Weather data can be used to refine the accuracy of the CVR prediction model.

Test

Fourteen substations were selected for a test group that is representative of the substations within the SMUD service territory. In order to tease out the CVR impacts from the natural load variability on substations, two major statistical approaches were used: ordinary least squares (OLS) regression and median regression. Both methods produced similar results.

The use of regression models allowed the inclusion of different weather variables and other variables, such as day of the week and photovoltaic (PV) generation, to aid in the detection of the CVR impacts. Weather combinations included variables such as cooling degree hours (CDH) and temperature-humidity indexes (THI), as well as variations in time dependence (i.e., current-hour values vs. moving averages).

Because SMUD has a sizable amount of PV systems installed at customer sites served by the test substations, generation data for 9 of the larger PV systems was provided so that the PV generation was accurately accounted for in the analysis.

For the core CVR analysis, SCADA substation-level load and voltage data at one-minute intervals (averaged to obtain hourly observations) were used.

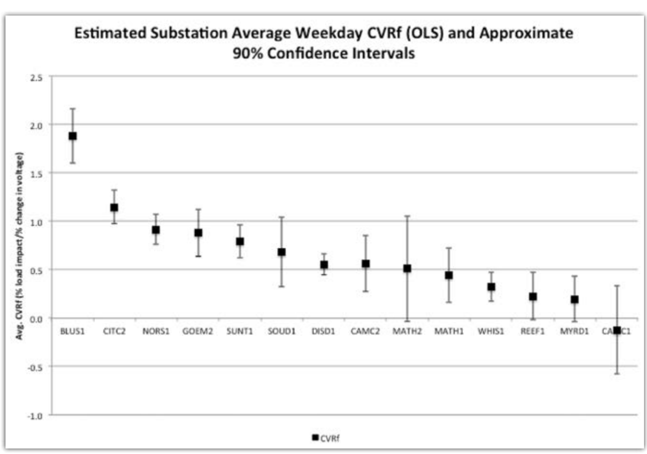
Results

Analysts found statistically significant average weekday load reductions, and associated energy savings, from CVR (averaged over all test hours) at eleven of the fourteen tested substations using OLS models, and at twelve using median regression. The overall average of the substation-level weekday CVRf estimate was 0.6 using both OLS and median regression.

CVR impacts were less likely to be statistically significant for weekend test hours. However, the weekend average CVRf was similar to the weekday average (approximately 0.6) excluding an outlying result at one substation.

The OLS and median regression estimated similar load reductions for the 2013 summer test period.

The figure below shows the substation average CVR factors and the associated 90 percent confidence bounds for weekdays, based on the OLS estimates. The 90 percent confidence interval bounds for the CVR factor are +/- 0.26 points on average. The positive weekday CVR factors that are not statistically significant at the 90 percent level, for the MATH2, MYRD1, and REEF1 substations, are statistically significant at approximately an 85 percent confidence level.



In the 2013 test, the model identified fewer statistically significant CVR impact coefficients for weekend days. The average weekend CVRf over all tested substations was approximately 0.3 using both estimation methods. Excluding a large wrong-sign impact at the MATH2 substation, which appears with both estimators, the average weekend CVRf was 0.5 for both OLS and median regression, similar to the weekday averages.

The estimated impacts by substation and hour are more statistically variable than the substation-average impacts. Only four of the tested substations had statistically significant impacts in most hours of the day in the OLS estimates—BLUS1, CITC2, DISD1, and NORS1. At most other tested substations, scattered individual hourly impacts were statistically significant, though most of the statistically insignificant coefficients imply CVR load reductions in those hours. The hourly coefficients that cause the wrong-sign impact estimates for CAMC1 and SUNT1 are, for the most part, not statistically significant individually.

Lessons Learned

Below are the key lessons from the 2013 test:

- Econometric models of weather-sensitive and periodic loads can explain a large fraction of the variation in load at the substation level in many cases.
- After data screening, ordinary least squares (OLS) estimation methods provide similar CVR impact estimates to median regression, a "robust" estimation method.
- Generally, the results suggest that the goodness-of-fit (R-squared) of a model of weather and periodic load effects may serve as a useful screening tool for substations where CVR impacts may be difficult to measure reliably. The three substations with relatively low R-squared values were likelier to exhibit anomalous or statistically insignificant impacts.
- The range of weekday substation-level CVR factors (excluding "wrong sign" results) was -0.1-1.8 using OLS and 0.0-1.6 using median regression; the overall averages of 0.6 when using either are within a plausible range for the CVRf.
- The customer mixes for the tested substations did not appear to have a major effect on the CVR impact estimates. However, for technical reasons, SMUD was unable to test a number of substations with relatively high fractions of use in residential-rate customers.
- While the average substation-level weekday load impacts were generally statistically significant, individual hourly impacts mostly were not statistically significant.

What's Next

Due to the fact that many of the individual hourly impacts were not statistically significant, the summer 2013 CVR evaluation was extended to be a one-year evaluation. Results of the year long evaluation will be documented in an upcoming case study.

For the full case study, available in the first quarter of 2015, search www.epri.com for product number 3002004622.

Sacramento Municipal Utility District

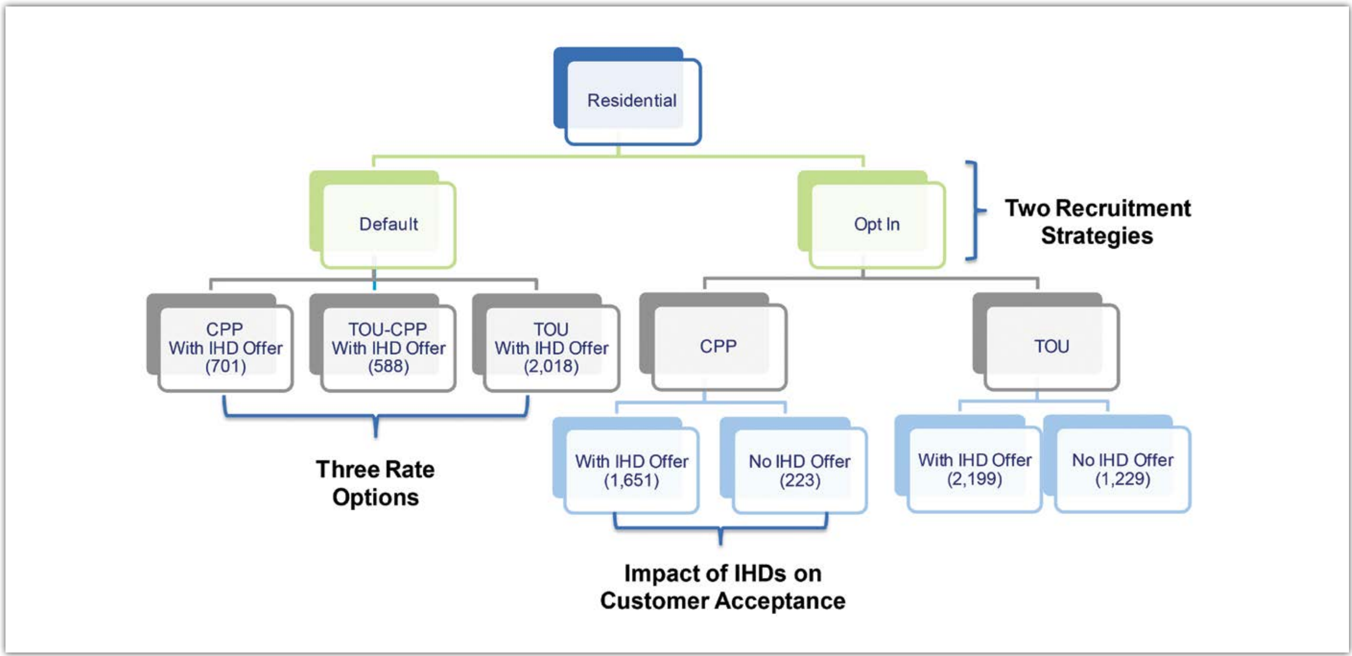


Figure 1 – Rate and technology combinations

Only 4-8% of the default customers chose to opt out of the randomly assigned rate assigned to them, whereas, the opt-in acceptance rate ranged from 15-20% and varied slightly across the plans. Both opt-in and opt-out participants had significant decreases in their average summer loads.

The SmartPricing Options Pilot at the Sacramento Municipal Utility District

The SmartPricing Options Pilot was undertaken to explore the effectiveness of AMI-enabled time-variant rate options in combination with enabling technologies for residential customers. The treatment options, recruitment strategies, and rate design enabled SMUD to simultaneously evaluate seven unique rate/ enabling technology combinations as shown in Figure 1.

The pilot was split according to two recruitment strategies: 1) default, which required customers to opt-out, and 2) an opt-in approach, which required customers to take action to participate. Each of the default customers were randomly assigned one of three rates: critical peak period (CPP), time of use (TOU), or time of use with a critical peak period (TOU-CPP). The opt-in customers were randomly assigned to one of two rate options, critical peak period (CPP), time of use (TOU), with some customers receiving the offer of enabling technology and others not receiving it. The default customers received notification that they had been enrolled in a time-variant rate program and were offered an in-home display (IHD) that showed energy use and costs during the different rate periods. In addition, all participants had the ability to access the SMUD web portal to obtain information about their energy use profile.

The opt-in customers were given the choice of a CPP or TOU rate. In order to test the influence of enabling technology on customer acceptance of the time-based rates, only a portion of opt-in customers on each rate were offered an IHD.

Objectives

The main objectives of the pilot project were to determine the following:

- Impacts of the three treatment strategies on energy consumption and demand
- Characteristics of customers based on behavior patterns
- Influence of enabling technologies on customer acceptance of the time-based rate options
- Anticipated value and market penetration of time-variant rates and supporting technologies

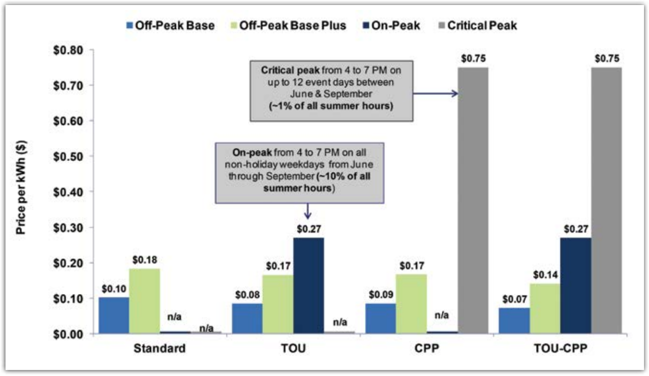


Figure 2 – Comparison between the three rates used in the SmartPricing pilot versus the standard SMUD residential rate

Approach

SMUD spent most of 2011 developing an effective marketing and educational campaign in order to enroll and maintain large enough sample groups for the pilot project. The project team conducted 25 focus groups and 4 surveys to solicit input for this campaign. The marketing messages and educational material were kept consistent for all the different treatment groups so that the communications with the participating customers did not influence the results of the pilot.

In order to determine the impacts of the rate and/or technology treatments, SMUD and their consultant, Freeman, Sullivan & Co., developed reference loads to estimate what the energy use would have been absent the change in rate and/or the addition of an enabling technology. The pilot project relied on a randomized control trial and a randomized encouragement design to develop reference loads. Including the control groups, almost 100,000 of SMUD's 620,000 customers participated in the SmartPricing pilot project. The number of customers in each of the individual rate and enabling technology treatment group is shown in Figure 1 in the parentheses.

Results

The following are key results of the pilot project.

- Average summer load impacts were significant for both opt-in and default pricing plans and higher for CPP than TOU customers.
- Customers on the Energy Assistance Program Rate versus those that were not had the same percentage load impact reductions on the default TOU plans.
- The average summer kW reduction between 4-7 p.m. was persistent across the two year evaluation period.
- Only 4-8% of the default customers chose to opt out of the randomly assigned rate assigned to them.
- The opt-in acceptance rate ranged from 15-20% and varied slightly across the plans.
- Based on a survey of non-participants that were offered more than one time-based rate option simultaneously, SMUD customers preferred the TOU to the CPP pricing plan by approximately 2:1.

Lessons Learned and Key Recommendations

- Documenting the business decisions and processes, especially for a multi-year project, is vital to continuity and knowledge transfer when there are changing resources and staff.
- Managing customer expectations throughout the recruitment and enrollment process is very important. Include as much information as possible regarding what the customer will experience during the study. If the customer feels informed, he or she will be satisfied with the experience.
- During recruitment, the choice of language to use with the customer was critical. This includes selecting layman terms for utility industry concepts and a friendly, neighborly voice for marketing collateral.

Next Steps

The success with and the customers' acceptance of the SmartPricing pilot has driven SMUD to consider a default residential TOU rate for 2018.

For a complete description of the project, search www.epri.com for product number 3002004641 (to be published in the first quarter of 2015).

Sacramento Municipal Utility District

On average, 91% of the committed load reduction was met in the automated demand response pilot.

The 2013 PowerDirect® Automated Demand Response (AutoDR) Pilot Program

The PowerDirect AutoDR Pilot Program provided medium and large commercial customers the opportunity to participate in one of four different types of demand response programs: Firm Load Reduction, a Minimum Dependable Load Reduction, Demand Response Peak Pricing, or Voluntary Load Reduction Pricing. The pilot program was operated via the Lockheed Martin SEEload™ Demand Response Management System (DRMS), which was used to schedule events, send event signals, and to settle performance transactions. The event days coincided with the SMUD "Conservation Days" when peak demand was high.

Project Objectives

- Deliver a program that offers ease of compliance and encourages a high degree of performance.
- Create value for SMUD customers and SMUD Energy Trading and System Operations.
- Design and test a demand response platform that is adaptive to SMUD and its customers' needs.
- Recruit 5-15 AutoDR customers for the pilot program.

Program Characteristics

The participants were required to have or install an OpenADR 1.0 client that could establish and maintain communications with the DRMS and the AutoDR-enabled control system. A technology incentive of up to $125/kW or a maximum of 100% of the AutoDR enablement cost was put in place to cover most of the costs to retrofit the customer's systems. The incentive payout was provided at project completion based on the verified demand reduction. Customer load reductions were determined by computer modeling and empirical data, by hour, by month, (Monday – Friday, June – September) for each customer.

The notification of event periods ranged from as short as 30 minutes to day-ahead. Events lasted from 1 to 4 hours. The notification was delivered by Televox, via voice and email. The event message was a predefined script for each method of communication.

Below are the key characteristics of each program:

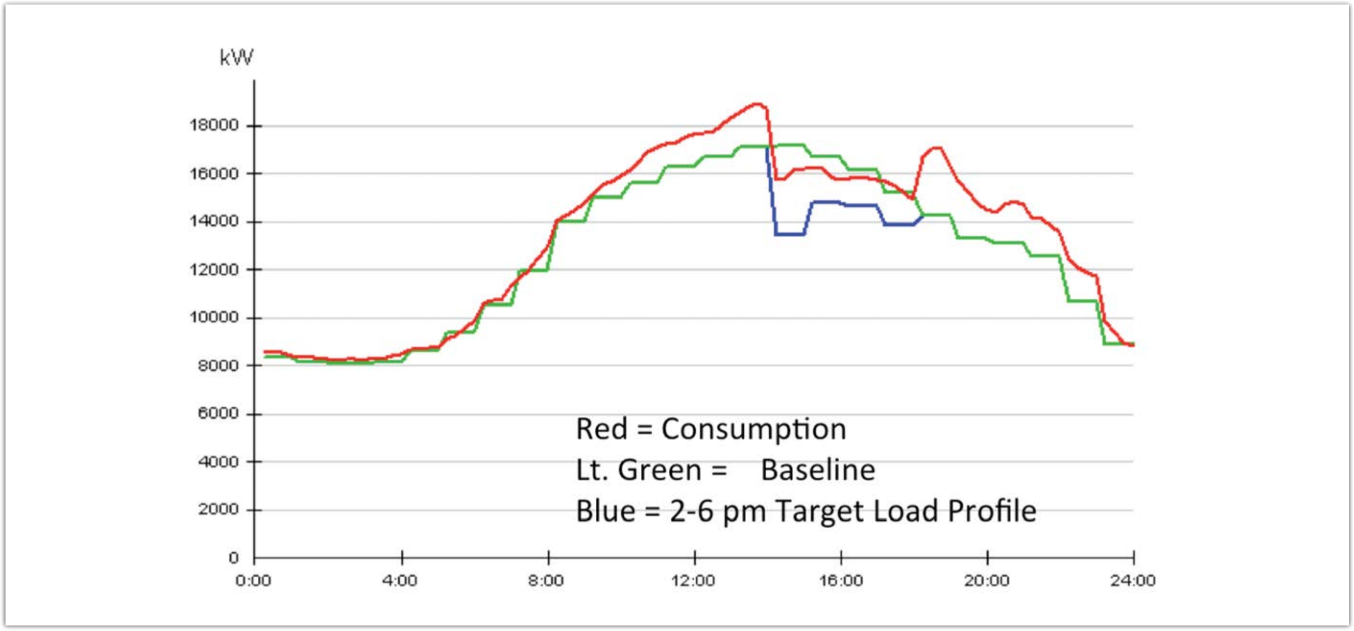
- Firm Load Reduction Program
  - Firm 50 kW minimum load reduction for 2 consecutive hours.
  - Baseline for performance and payment.
  - Capacity payment of $2.30 kW/month, 4 summer months.
  - Energy payment of$0.12/kWh for energy reduction from baseline.
  - Performance: No penalties or liquidated damages. Must perform to firm load level for each hour for energy payment.
  - First opt-out forfeits the capacity payment for the month. The 2nd opt-out forfeits the capacity payment for the year.
- Minimum Dependable Load Reduction (MinDLR) Program
  - 50 kW minimum load reduction for 2 consecutive hours.
  - Baseline for performance, capacity and energy payment, and the opt-out forfeits are the same as the Firm Load Reduction Program.
  - Performance: No penalties or liquidated damages. Must perform at 50% to 150% of MinDLR each hour for payment.
- Demand Response Peak Pricing Program
  - Tariff structure utilizes a super-peak increment (adder) and an off-peak decrement (discount) applied to the existing TOU rates.
  - Peak pricing based on modeling of customer impacts.
  - Super peak price adder is + $0.50 per kWh.
  - Off-peak price adjustment of $0.02 per kWh.
- Voluntary Load Reduction Program
  - No minimum load reduction commitment.
  - Performance and settlement is based on hourly energy delivery from the baseline.
  - Energy payment of $0.11/kWh.
  - No capacity payment, penalties, or liquidated damages.

Results

For this automated DR pilot consisting of 9 customers, SMUD dispatched a total of ten times between June 1 and September 30, 2013 during the peak weekday period of 2 p.m. to 6 p.m. The load reduction was determined by comparing the participants' actual demand during event hours to that of their calculated baseline. For the 10 events, an average load reduction of 2.204 MW was achieved versus the 2.422 MW committed to the program. Overall the pilot project delivered 41.5 MWh of energy and 3.4 MW of peak load reduction.

The figure below shows a typical event day graph. The red line shows the actual energy load profile as compared to the baseline (green line) and target (blue line) load profiles for aggregated loads of the participating customers.

When surveyed, 90% of the participants responded that they were satisfied with the pilot program.



Lessons Learned

Below are the key lessons learned during the pilot program:

- Analysis and practice showed that the target load reduction could be calculated with a high degree of certainty.
- The ability to remotely install configuration changes in client devices is very important.
- Given the limited time available, commercial customers with advanced control capability proved to be better candidates for the pilot.
- Retail, campus, and commercial buildings were well suited for the Minimum Dependable Load Reduction Program but not the Firm Load Reduction Program.
- The Demand Response Peak Pricing Program was best for customers who could limit peak demand significantly and effectively manage their off-peak load to maximize the benefit.
- The Voluntary Load Reduction Program was ideal for customers that were unsure of their actual load reduction capability.
- Direct customer human interaction is not required for event participation, leading to high reliability because of ease of participation and automation.

Next Step

The pilot continues in 2014 and is scheduled to move into full program operation in 2015.

For a complete project description, search www.epri.com for product number 3002004641 (to be published in the first quarter of 2015).

Sacramento Municipal Utility District

This is an example of attempted power theft. The customer drilled through the meter cover to install a stick on a button that is used to place the meter in a diagnostic mode.

> *Use of theft detection software can help utilities with advanced meters to reduce revenue losses. For SMUD, this equated to 15.5 million kWh or $3 million in the first 12 months.*

SMUD Revenue Protection Software

When it completed rollout of advanced meters in 2013, SMUD implemented data analytics software to identify instances when a meter had been tampered with, by-passed, or had simply malfunctioned. Traditionally, SMUD meter readers would identify such issues while reading the meters each month. In order to meet or exceed the standard set by this manual inspection process, SMUD installed revenue protection software provided by Detectent, Inc. This software generates leads for on-site investigation based on results from theft detection algorithms that process numerous datasets from different utility systems as well as external sources.

Project Objectives

The primary purpose of this project was to replace physical inspections with data analytics in order to achieve numerous objectives, including:

- Protect the customer and SMUD employees from potentially unsafe conditions due to someone tampering with the meter.
- Reduce annual revenue loss from theft.

Methodology

The revenue protection software compiles utility and third party datasets for evaluation. The utility data used by the software includes datasets from the advanced metering infrastructure (kWh, voltage, register, alarm, event, and other alert data), the customer information system (customer, premises, billing, and service notifications) and from the geospatial information system (GIS). External or third party datasets, such as county assessor property information, weather data, and demographic data are also utilized. Almost all of the datasets are updated daily with the exception of the GIS and county assessor datasets which are updated weekly and quarterly, respectively. In addition, SMUD attempts to query the datasets monthly to identify and to fill gaps in the datasets missed by the daily updates.

	2011	2012	2013	12 Months Prior to Detectent	12 Months after Detectent
$ Billed	$1,752,820	$1,120,860	$2,953,334	$1.36M	$3.11M
kWh Billed	9,912,680	5,009,350	13,738,497	-	-
$ Collected	$138,020	$337,030	$653,418	$334k	$723k

This table illustrates the billed amount versus the collected amount associated with theft cases. The increases from 2011-2012 to the first 9 months of 2013 are largely driven from the use of the detection software to identify theft cases and determine which customers are more likely to pay, such as commercial customers. The last two columns show a 4-month comparison between June-Sept of 2012 and 2013.

The software identifies and prioritizes the most likely theft cases. The rich datasets enable SMUD's revenue protection analysts to generate leads for investigation, using 20+ theft detection algorithms. Simple leads, such as "zero usage" that matches disconnection orders, are usually viewed and closed without a field inspection. The leads requiring field inspection are prioritized based on weighting criteria defined by the analysts. The weighting criteria are continuously adjusted so that investigation and recovery activities are optimized.

Results

The revenue protection software permitted SMUD to move from a reactive response, which relies on tips from the public and from SMUD employees, to a proactive response, which is based on statistical analyses to make inferences and identify possible theft.

SMUD has benefited from the technology and has reduced revenue loss. However, the methodology that SMUD uses to track various types of leads makes it difficult to pinpoint the actual success rate of the generated theft leads. For example, the system assigns a new order each time an investigation is undertaken. If the original investigation determines that there is theft occurring and the meter is removed, all subsequent follow-ups to the premises are issued a new investigation order even though each one relates back to the original order.

Although the precise theft detection success rate is elusive, SMUD does assign the following benefits to the detection software, and is starting to see trends, such as increases in the kWh billed and dollars collected, as shown in the table above.

Benefits to the customer:

- Improves customer safety by better identifying meter tampering.
- Reduces revenue loss that would negatively impact customers by contributing to future rate increases.

Benefits to the utility:

- Improves employee safety.
- Prioritizes leads based on ones with the highest probability of theft.
- Provides efficient use of SMUD resources (labor, fuel, investigation costs, and software).

Lessons Learned and Recommendations

A number of lessons were learned by SMUD during 2013-2014 on use of the detection software:

- Some customization of the software is needed so that it works well with utility processes, and increases the efficiency of the workforce. For example, at the beginning of the project, SMUD adjusted the standard software so that it operated efficiently with the SMUD systems and provided reports that closely matched the ones that SMUD employees were accustomed to working with. Also, algorithms were adjusted to increase the probability that each lead was a case of theft. At a minimum, SMUD recommends that a utility implementing a revenue protection data analytics program uses the following types of algorithms: kWh drop, meter set, minimum kWh usage, zero use, frequent tamper, load factor, meter capacity, max monthly usage, reverse power, high seasonal load, load factor deviation, similar customer comparison, and other demographic comparison algorithms.
- Purge non-essential data periodically to alleviate huge data storage. The data that is entered daily provides a wealth of information but can be burdensome to store over time. The large set of data can be utilized to reduce the estimated (electric utility industry average) 0.5-1% of SMUD revenue lost to theft each year. As the amount of data grows over time, SMUD recommends purging non-essential data periodically. SMUD purges data after two years. Essential data, such as investigation records, algorithm performance indices, and other important case data is stored permanently.

For the full case study, to be published by he end of 2014, search www.epri.com for product number 3002004623.

Sacramento Municipal Utility District

With the use of a programmable thermostat, customers are more likely to reduce peak demand and minimize their bills by participating in a time-of-use/critical peak pricing program.

The PowerStat Study Conducted at Sacramento Municipal Utility District

The SMUD PowerStat study was conducted in 2013 to determine how a time-of-use (TOU) rate, critical-peak pricing (CPP), and direct-load control (DLC) of air conditioning (AC) units impacted hourly loads during the summer. Each of the customers who opted to participate in the study received a two-way communicating thermostat, the Energate Z100 Pioneer 2 thermostat shown in Figure 1, to help manage energy use by controlling cooling, one of the largest loads in most homes.

Participants could select one of three options: 1) TOU/CPP rate and self management of the thermostat, 2) TOU/CPP rate + DLC with a defined range of thermostat offsets during event days, and 3) DLC with a standard rate, SMUD control during events, and a credit paid for each event. A randomly selected control group was also part of the study. Each option has a defined offset range. For Option 1, the offset values ranged from 1 to 5 degrees (maximum comfort to maximum savings). Customers with Option 1 were permit to change the offset value as often as they wished. Option 2 and Option 3 had fixed offset values of 2, 3, or 4 degrees as specified during sign up.

SMUD sought to determine customer preferences for each of the voluntary options and for perceived comfort levels during critical peak period events or "Conservation Days."

Approach – Thermostat

The programmable thermostat was the core component of the energy management portion of the project. The thermostat had factory installed settings, as shown in the table, to minimize energy use, but these could be modified by the customer and installer at the time of installation. For Option 1, the thermostat also had a relative price-to-comfort setting that allowed the customer to choose the comfort level to maintain during critical peak periods. Based on the price and the comfort setting, the customer could save 11-55% during high energy price periods.

Price, event, and other information were sent to the thermostat via the SMUD Silver Springs Network to the meter, and then Zigbee was used to pass the information from the meter to the thermostat.

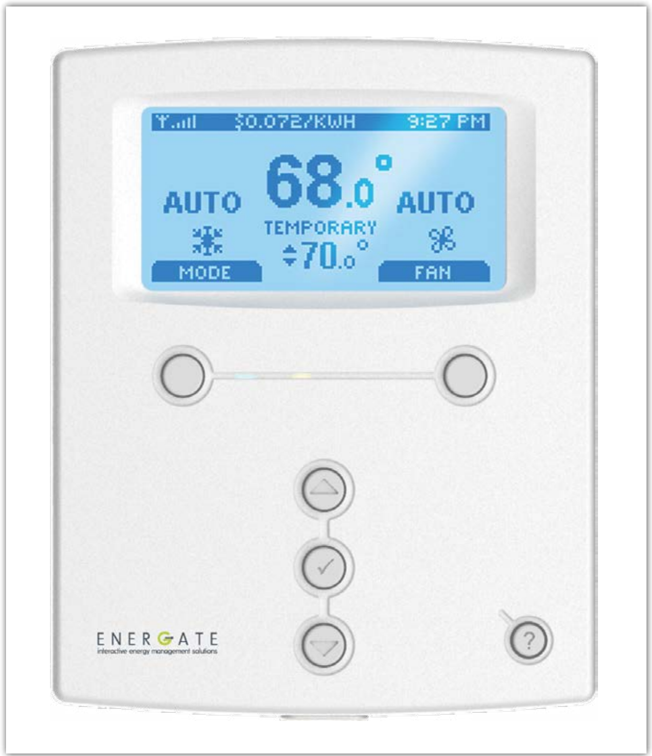


Figure 1 – Energate thermostat

Factory Settings of Thermostat			
Monday – Friday			
Start Times	**Set Point**		
Phase	**Name**	**Heat**	**Cool**
6:00 AM	Wake	68.0° F	78.0° F
8:00 AM	Leave	62.0° F	80.0° F
6:00 PM	Return	68.0° F	78.0° F
10:00 PM	Sleep	62.0° F	78.0° F
Saturday – Sunday			
Start Times	**Set Point**		
Phase	**Name**	**Heat**	**Cool**
8:00 AM	Wake	68.0° F	78.0° F
11:00 PM	Sleep	62.0° F	78.0° F

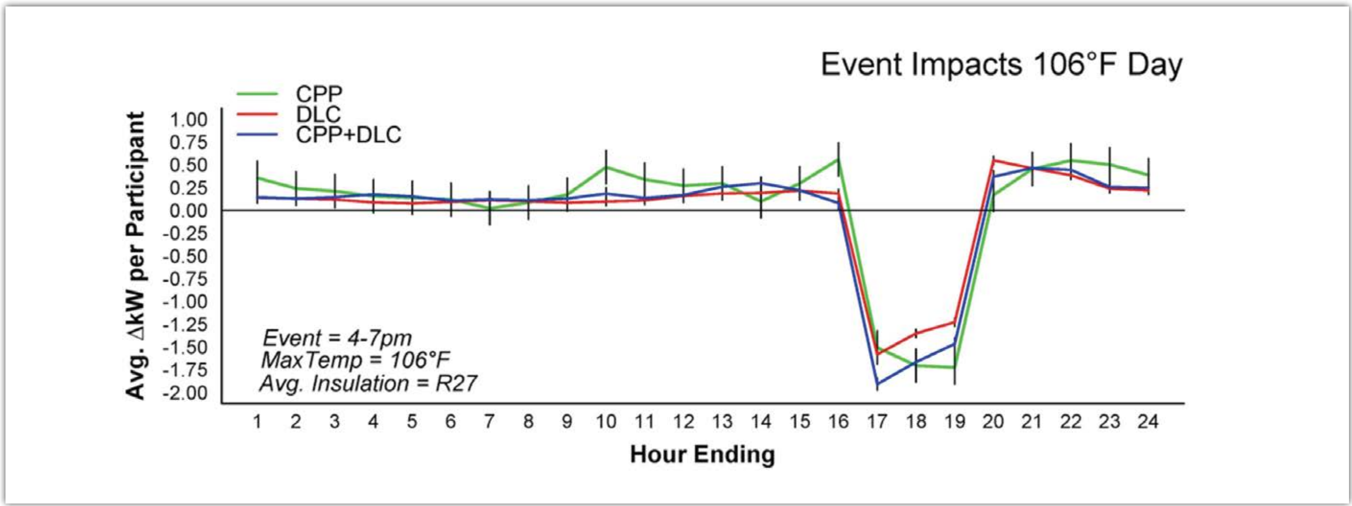


Figure 2 – Savings for all three groups

Approach - Study Design

The characteristics of the four study groups are as follows:

- TOU/CPP (sample size (n) = 39) – Participants were placed on a rate that included 12 event days. The option of self-management of the thermostat provided this group with the flexibility to manage energy use and resulting bill savings. The participants managed event period usage by selecting a +1°F to +5°F higher temperature set point for cooling.
- TOU/CPP + DLC (n = 288) – As with the TOU/CPP participants, these customers had the ability to manage AC and non-AC load throughout the study period to maximize bill savings on the TOU/CPP rate. During events, the utility managed the thermostat by enforcing a +2°, +3°, or +4°F higher temperature set point without payment. An unlimited number of overrides of events were permitted.
- DLC (n = 509) – Participants were paid $2, $3 or $4 for each of 12 events at a +2°, +3°, or +4° higher temperature set point, respectively. An unlimited number of overrides of events were permitted but resulted in a forfeiture of the event incentive.
- Control group (n = 413) – The control group consisted of randomly selected customers who had no significant load changes from 2012 to 2013 (temperature adjusted).

Results

The following are the highlights of study results:

- Participants reduced peak loads by 41% or 1.45 kW on average. Example of the savings for all three groups for a 106°F day is shown in Figure 2 (Note that TOU/CPP is abbreviated as CPP in the graph).
- TOU/CPP and TOU/CPP + DLC peak reduction was almost identical at 46%.
- As the outdoor temperature increased, the demand reductions for all groups increased.
- Of the 84% of participants who were home at least 30 minutes during the events, 57% felt their home was comfortable during the event hours (4-7 p.m.), 39% indicated their home was a bit hot, and 4% felt their home was too hot.
- The monthly bill savings were $15, $13, and $9 for the TOU/CPP + DLC, TOU/CPP, and DLC groups, respectively.

Lessons Learned and Recommendations

- Installers did not follow the installation process all of the time, which led to input errors. This could be overcome with the use of barcode readers to input information.
- The number of options for the study was overwhelming to some customers. Simplification of the marketing material or a reduction in the number of study options would eliminate most of the confusion.

For a complete description of the project, search www.epri.com for product number 3002004641 (to be published in the first quarter of 2015).

Salt River Project

Deploying a private network requires a substantial initial investment, but has the potential to provide a long-term payback, especially if the field area network is used extensively for applications with high data transfer requirements.

Salt River Project (SRP) is a collaborating member of the Smart Grid Demonstration Initiative. As part of its preparation for the smart grid, SRP conducted a Field Area Network Pilot. This effort positions SRP to meet the future wireless communications needs for the proliferation of intelligent electronic devices (IEDs) beyond substations.

A Field Area Network (FAN) Pilot at Salt River Project

SRP's existing wireless communication systems could be characterized as first generation. These systems are unique-point solutions, each typically servicing only one application. They include 900 MHz licensed and unlicensed point-to-multipoint, paging, 900 MHz unlicensed mesh, and public carrier systems. SRP envisions the majority of these systems will be unified using a wireless broadband network. This field area network is intended to provide network connectivity and services for a variety of applications, including distribution feeder automation, volt-var optimization, water SCADA, line and transformer monitoring, AMI backhaul, and security video from IP cameras.

The four main elements of the FAN pilot, done in partnership with EPRI, were 1) an analysis of technical options for the FAN infrastructure, 2) a FAN pilot deployment, 3) cyber security penetration testing, and 4) a cost-benefit analysis of the applications that could benefit or be enabled by the FAN.

Approach

Several approaches to FAN implementation were considered and analyzed:

- Exclusive use of services from one or more public wireless carriers
- A private field area network deployed and managed by SRP
- A hybrid combination of public and private field area networks
- A network shared with public safety in the 700 MHz band, in cooperation with FirstNet (First Responder Network Authority)

The project was conducted from 2012-2013. Specific elements included:

- Development of use cases for key applications that aligned with communication over a FAN.
- A FAN technology implementation assessment. Long-term evolution (LTE) technology on licensed spectrum, WiMAX on 3.65GHz, and WiFi Mesh were evaluated.


WiMAX system equipment was among the technologies tested in the pilot. Evaluation of responses to a request for proposals led to a split award for 3.65GHz WiMAX equipment from GE and Airspan.

- Cyber security penetration testing that resulted in the identification of several vulnerabilities.
- Deployment of a limited-scale system for a private FAN network.
- A cost-benefit analysis of the options, considering the uses cases to be supported, and the estimated costs for deployment that were derived from the technical analysis.

Results

Following are key findings regarding technology and network options:

- *Technology assessment.* Field tests validated that the RF planning studies' predicted coverage and range was close to what was actually measured, and also revealed that the 3.65 GHz band was occupied by other users operating without proper licensing. LTE is a preferred technology, but licensed spectrum is an issue at this time.
- *Public networks.* The technical capability of all the carriers appears to be adequate in terms of coverage, capacity, and performance. One significant shortcoming is lack of quality of service (QoS) and admission control in public networks. QoS allows relative prioritization of applications traffic with respect to each other. Admission control ensures that the SRP devices are able to join the network, even in emergency situations when the network might be flooded with retail wireless customers.
- *Private networks.* Deploying a private network requires a substantial initial investment, but has the potential to provide a long-term payback, especially if the field area network is used extensively for applications with high data transfer requirements.
- *Hybrid networks.* To deploy a hybrid network consisting of both private and public elements may be challenging. It may be difficult to derive benefits of running two parallel networks in the same area, which is not often the case, unless applications are geographically compartmentalized. Furthermore, hybrid networks increase in complexity because of deploying and maintaining multiple technologies, with differences in configuration and security parameters.
- *A shared public safety network.* The public safety network was not considered a viable option for several reasons. Among those are that 1) state initiatives for the development of FirstNet are too far in the future, 2) parameters for "secondary use" of the network by utilities have not been defined, and 3) cost models for both deployment and network usage are as yet completely unknown.

Lessons Learned & Key Recommendations

- For a utility that wants to make maximal use of a FAN, with many data-intensive applications, the ongoing cost for public carrier data becomes an issue. Other concerns with public carrier networks center around lack of quality of service (traffic priority) guarantees on public networks, control of security and network management by a third party, and restoration after storms or natural disasters.
- When comparing private and public network options, consider the amount of data that the private network can carry, and assign a monetary value as if the data was being carried by a wireless carrier. The capacity of a private FAN, and thus the value of its data, can be surprisingly high.
- Defining the FAN use cases and discussing them with the internal experts responsible for each use case was a valuable exercise. It yielded better understanding of the requirements for the FAN, and increased collaboration between the SRP communications department and other departments that might not otherwise interact.
- The cost-benefit analysis for the FAN was not as clear-cut as some because of the difficulty in separating out the value added by the FAN alone from the value of the applications that are enabled by the FAN but could potentially use some other type of communication.

Next Steps

The SRP FAN team has proposed that a private wireless broadband network be built, as it enables advanced grid automation, customer application benefits, and cost optimization. This will require licensed spectrum acquisition, which is being pursued.

For the full case study, available by the end of 2014, search www.epri.com for product number 3002004646.

Southern California Edison

The capacitor banks have performed satisfactorily throughout the demonstration period whether controlled by the DVVC algorithm, or by their internal, stand-alone settings.

The objective of **Southern California Edison's Irvine Smart Grid Demonstration (ISGD)** is to verify, quantify, and validate the feasibility of integrating smart grid technologies. The project is showcasing advanced technologies necessary to support a smarter, more robust electricity infrastructure that will be critical as the country begins to rely on greater amounts of renewable generation and the use of electricity as a fuel for vehicles. The project also engages consumers to become active participants in the energy supply chain. The Irvine Smart Grid Demonstration encompasses four key areas addressing a broad set of requirements: 1) energy smart customer devices, 2) year 2020 distribution system, 3) secure energy network, and 4) workforce of the future.

Distribution Volt-Var Control to Optimize Customer Voltage: Irvine Smart Grid Demonstration

This project demonstrates the use of distribution volt-var control (DVVC) to optimize customer voltage profiles and save customers energy. Southern California Edison currently uses technology that was developed many years ago to maintain customer voltage within the lower half of the required customer voltage range, as designated in the American National Standards Institute (ANSI) C84 standard and California requirements (114 to 120 volts at the customer service connection). This project demonstrated an updated approach to maintaining customer voltage using a new control algorithm.

The new DVVC algorithm was developed using SCE's patented volt-var algorithm from its previous Distribution Capacitor Automation Project (DCAP), which was initiated in 1992. The key to successful capacitor automation is to implement a smart centralized control algorithm that uses primary circuit voltage as well as watt and var measurements at the substation to operate substation and field capacitors. The new DVVC algorithm solves for the optimal system capacitor switching combination that will satisfy user-defined constraints for minimum and maximum voltage and reactive power flow. Actual customer voltages provided by Edison SmartConnect™ meters are being used to verify system performance.

Goals & Objectives

The project has two overall goals. The primary goal of the project is to reduce average consumer voltage in order to decrease associated energy use. The second goal is to utilize the system to optimize var flow at the substation transformer bank.

Approach/ Methodology

The following steps were undertaken to achieve project goals and objectives:

- Design the DVVC control algorithm to optimize the voltage and vars on each circuit by dynamically controlling substation and field capacitors.
- Implement the DVVC algorithm as part of SCE's distribution management system (DMS).
- Utilize existing capacitor controls through use of the NetComm radio system.
- Test the DVVC on 7 circuits connected to the same bus at MacArthur Substation.

The field apparatus and systems comprising the DVVC were evaluated in SCE's Advanced Technology Laboratory to verify proper operation of the equipment and determine system performance. Integrated system testing was also performed in the lab setting, where possible.

The DVVC was deployed at the MacArthur Substation in 2014 and will continue evaluation through the year 2015.

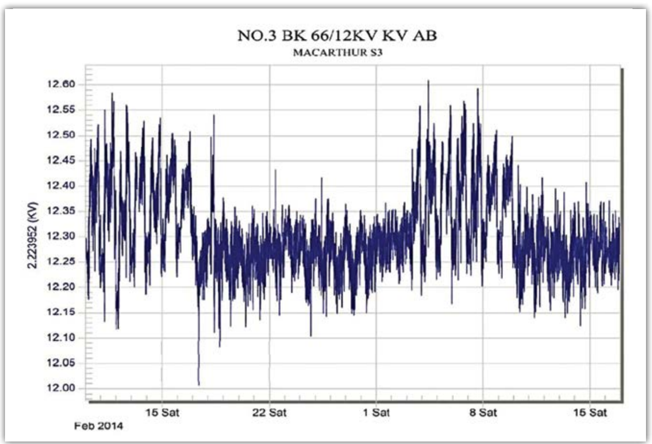


Figure 1 – Voltage reduction at substation bus on alternating weeks

The graph in Figure 1 demonstrates voltage reduction at the MacArthur Substation bus on alternating weeks in February and March 2014 when DVVC was running. This reduction translates to approximately a 2 volt system average reduction at the 120V services of customers on the 7 circuits at the MacArthur Substation.

The chart in Figure 2 illustrates the ability of DVVC to regulate reactive power flow (var) at the MacArthur sub transformer secondary. The algorithm was set to provide leading reactive power, such as from the distribution network to the substation transformer. The result is indicated on the graph by the decreasing negative values for Mvars.

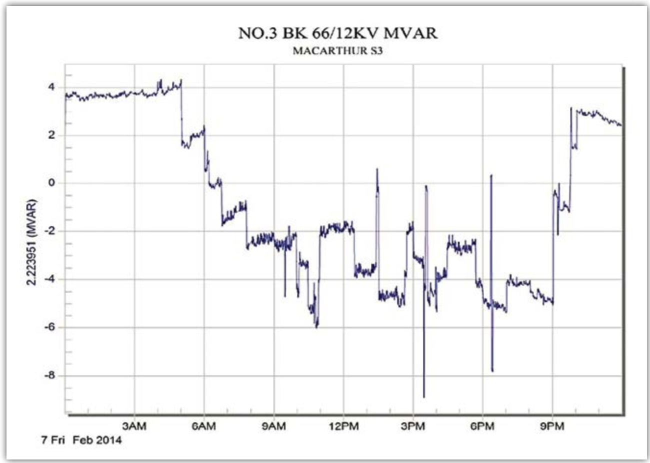


Figure 2 – DVVC Regulation of reactive power

Results

To date, the DVVC application has been proven to successfully optimize customer voltage and regulate reactive power flow at the substation transformer secondary. Tests have been conducted resulting in a system average voltage reduction of 2V at the customer service entrances. Additionally, tests have been conducted that cause the distribution system to provide reactive power to the substation transformer.

The capacitor banks on the MacArthur Substation distribution system have performed satisfactorily throughout the demonstration period, whether controlled by the DVVC algorithm, or by their internal, stand-alone settings. Since the DVVC algorithm control relies on the Netcomm communication system to tranmit commands of the algorithm from the SCADA System (DMS) to the radios of the programmable capacitor controllers, additional radios/routers have been added to the MacArthur network during the demonstration period to ensure a more reliable success rate of controls reaching the capacitor controllers.

SCE expects to achieve customer energy savings and a reduction in capacitor switching operations; data on whether these goals are reached is being collected during 2014.

Next Steps

Assuming the DVVC application continues to operate successfully, in 2016 the DVVC system will begin to be implemented system wide. The roll-out will leverage the advanced DMS applications, substation automation capabilities, the utility algorithm, the existing SCE Netcomm wireless network (~50,000 devices), as well as existing automated capacitor banks (~10,000 installed devices).

For the full case study, slated for publication in the first quarter of 2015, search www.epri.com for product number 3002004612.

Southern California Edison

MacArthur Substation

> *IEC 61850 provides many benefits; however, vendor implementations are inconsistent and make integration of a multi-vendor system difficult.*

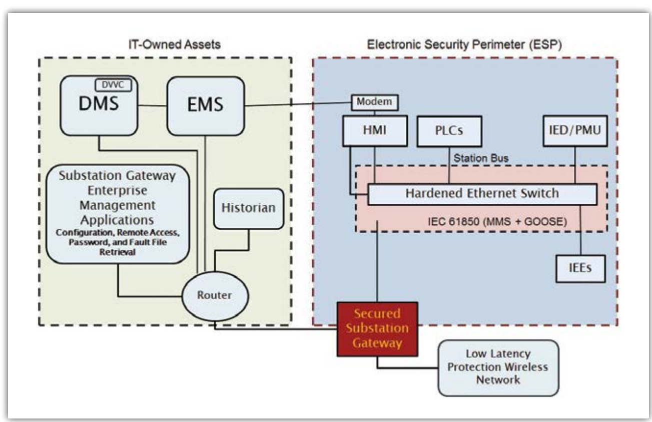
Substation Automation: Irvine Smart Grid Demonstration

Southern California Edison (SCE) is piloting next generation substation automation at its MacArthur Substation as part of its Irvine Smart Grid Demonstration (ISGD). SCE's next generation system is referred to as Substation Automation 3 or SA-3. The SA-3 project team selected IEC 61850 as the standard to use as the foundation of project design. The SA-3 platform enables standards-based communications, automated configuration of substation devices, and an enhanced system design.

The MacArthur Substation SA-3 pilot is demonstrating the following:

- A data-driven Human Machine Interface (HMI)
- Device password management
- Automated device configuration management
- Secure, remote access
- Integration of SCE's Common Cybersecurity Services (CCS)
- Streamlined data-driven enterprise and substation configuration processes
- Automated HMI and Energy Management System (EMS) test scripts
- Automated fault file collection
- Power systems simulator substation automation testing

The network architecture of the system is shown in the figure below.



SA-3 Network Architecture

Approach/Methodology

The primary objective of the research was to increase understanding of how to use IEC 61850's configuration capabilities to reduce the levels of human intervention, reduce errors, and improve engineering time.

The SA-3 project was broken down into the following three sub-projects:

SCE's Substation Engineering Modeling Tool (SEMT) was originally developed for consistent generation of HMI point list for communications to the Energy Management System. The capabilities of SEMT were expanded to serve as an IEC 61850 System Configurator, capable of generating all the configuration files required to configure substation automation devices, including intelligent electronic devices (IEDs), managed switches, substation gateways, and HMI. The SEMT also generates reports such as point lists and test scripts used for automated testing.

HMI Project entailed replacement of SCE's proprietary and aging legacy HMI system, which required excessive configuration and maintenance support work-hours. HMI was based on the IEC 61850 standard. The new HMI minimized manual keystrokes in development of project files, database, and graphical user interface (GUI).

Substation Gateway 61850 Project resulted in the demonstration of a secure Ethernet communication interface to SCE substations for serving all system Data Beyond SCADA (DBS) to the eDNA enterprise server. Development included demonstration of remote, secure access to substation edge devices by authorized Protection and Engineering personnel.

Each of the projects was first developed and tested independently. Once the individual system components were proven, a complete system test was performed. To aid in the system test SCE developed a robust testing platform using power system simulation where ideas could be implemented and tested efficiently. The setup also served as an ideal training platform for operators of the new HMI. The benefits of power system simulation and scripted testing might prove to be beneficial to Factory Acceptance Testing (FAT) and Site Acceptance Testing (SAT).

Results

This substation automation project has been deployed in the field. Key results as of 2014 include:

- HMI configuration: The project has successfully demonstrated an HMI that can be fully configured with the data driven process in minutes, providing significant improvement compared with the existing manual process, which takes several weeks.
- Security: The SA-3 project is the first substation deployment of SCE's Common Cybersecurity Services (CCS) platform. The security system was designed to meet NERC cyber security requirements for protection of critical cyber assets. SCE will continue evaluating the cyber security system for the duration of the ISGD project.
- Personnel training: Training material on the SA-3 system was developed to provide a reference for test technicians, operators, and maintenance. As part of the training program the test technician and operators in the area were provided hands-on training.
- System issues: During the course of testing, the team encountered several glitches with the components and operation of the system. For example, while testing the back-office software, numerous issues were discovered and the team worked closely with the vendor to fix problems.

Lessons Learned & Recommendations

- IEC 61850 products have limited interoperability. Many manufacturers offer products that are IEC 61850-compliant. However, their implementations of the standard were inconsistent, resulting in devices from different manufacturers that could only communicate at a very basic level. This limitation led to longer-than-expected laboratory testing, re-engineering, and coordination with product manufacturers.
- Utilities considering an advanced substation automation system should establish key system requirements and determine which existing systems will be affected. Some systems may be unable to interface IEC 61850, and could require replacement.
- As a new substation automation system integrates or replaces operational systems, it will lead to procedural changes.
- The relationship between departments responsible for IT, security, and the substation—and between their respective vendors—must be addressed in the planning process. Having all vendors under a single point of contact may be one way to ensure coordination.

Next Steps

The project team will perform additional work and data collection in 2015. This includes:

- Replacing serial communications with Ethernet.
- Integration of SA-3 with the SCE's legacy automation systems.
- Apply the SA-3 solution to the bulk electric system.
- Investigate application of additional IEC 61850 features such as, high availability protocols, routable GOOSE (generic object-oriented substation events) messaging, and process bus.
- Incorporate computer aided drafting (CAD) to help automate design and modeling processes.
- Based on pilot results, make recommendations for new substation design to the SCE planning board for consideration.
- Make recommendations to IEC 61850 user groups regarding gaps found in the standard.

For the full case study, available by the end of 2014, search www.epri.com for product number 3002004613.

Southern California Edison

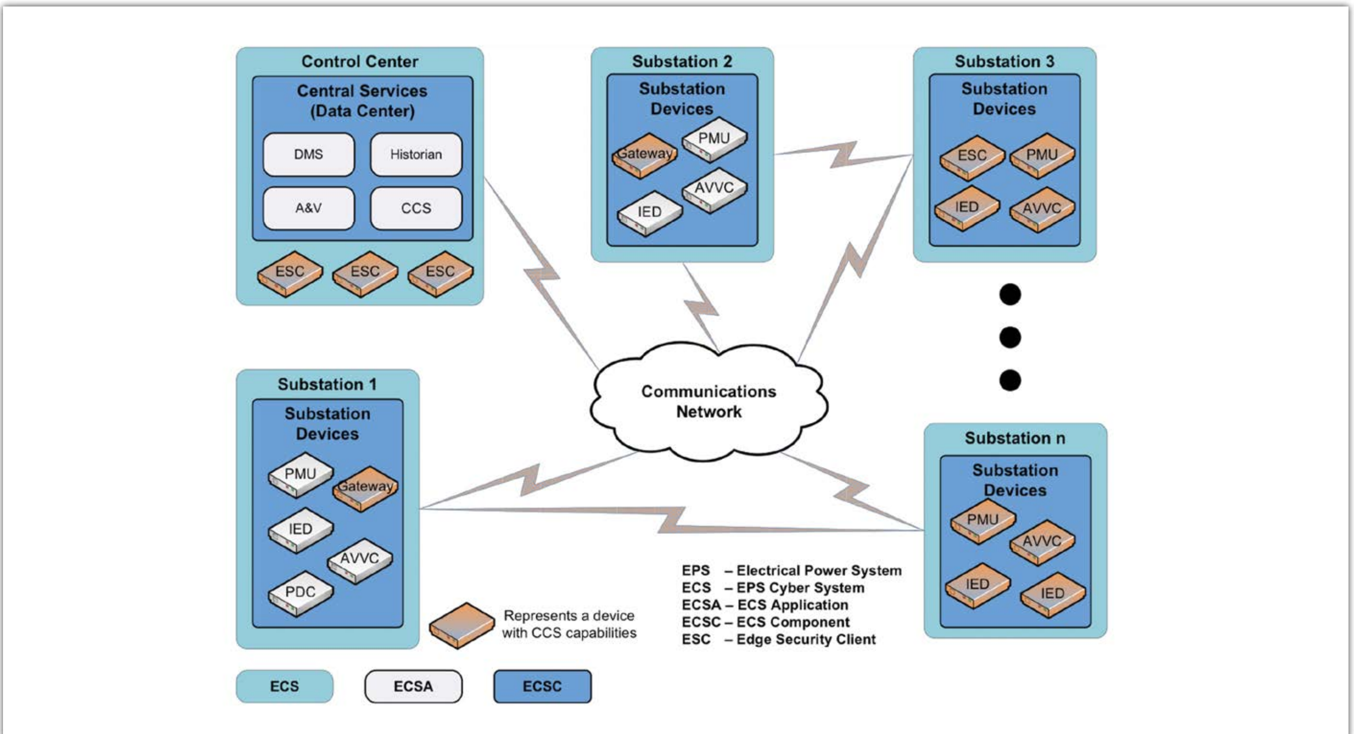


Figure 1 – CCS Operational View

A critical challenge of deploying a smart grid is having a consistent view of cyber security across all applications. External interfaces should be protected with sophisticated boundary defenses that provide multiple layers of defense against intrusion.

Cyber Security at Southern California Edison

Southern California Edison (SCE) developed advanced cyber security architecture to protect its smart grid applications as well as its legacy systems. The evolving electricity sector is increasingly dependent on information and communication technology to ensure the reliability and security of the electric grid. Cyber security measures must be designed to protect these systems from malicious attacks and also strengthen grid resilience against natural disasters and inadvertent threats such as equipment failures and user errors. SCE created its Common Cybersecurity Services (CCS) architecture to address these threats and provide increased cyber security situational awareness for its power delivery systems.

Project Objectives

- Keep pace with new technology adoption
- Support next-generation applications as well as legacy systems
- Comply with all regulations and relevant standards
- Adhere to a common services architecture that reduces implementation and operational costs through reuse

Research and Results

CCS meets project objectives by delivering a common service for securing smart grid applications and devices. It leverages standards-based technology to avoid proprietary solutions and technology developed for the U.S. Department of Defense to protect smart grid devices. Additionally, CCS uses a service-oriented architecture (SOA) and modular design. These characteristics allow it to support current and next-generation networking as well as all major protocols used in the grid.

The CCS architecture is built on several core cyber security capabilities:

- Authentication: Public key infrastructure (PKI), identity management, attribute certificates (bill of health (BoH))
- Authorization: Centrally managed and configured security associations (SAs)
- Accounting: Audit and reporting (alerts, Syslog); security information and event management (SIEM) appliance
- Integrity: Integrity management authority (IMA); trusted network connect; bill-of-health
- Quality-of-Trust: Source-based data labeling (trusted, questionable, or untrusted)
- Peer-to-Peer Communication: Peer-to-peer middleware using Data Distribution System (DDS) (used only for control plane)
- Dynamic, Interactive GUI: Accessed via web browser; built-in test and peek-poke capabilities

Operational View

Figure 1 provides an operational view of the CCS architecture. Since a key objective of CCS is to support legacy systems as well as smart grid devices, a mixture of CCS-capable and legacy devices is shown in the figure. Substations with legacy devices leverage a CCS-capable substation gateway device to support legacy device interoperability and provide security protections. The substation gateway is a cyber-secure access point to the substation and distribution network data. It provides firewalled, secure access to the substation, meeting NERC CIP (North American Electric Reliability Corporation Critical Infrastructure Protection) compliance requirements.

To block indirect introduction of targeted malware into the substation, external interfaces are protected with sophisticated boundary defenses that provide multiple layers of defense against intrusion, including strong authentication of external entities, cryptographically protected communications, and content inspection of all traffic that crosses the substation boundary. New smart grid devices that have CCS capabilities built in support several core security services, including key management, configuration management, audit and reporting, integrity checking, and boundary enforcement services.

Situational Awareness

A critical challenge of deploying a variety of smart grid systems and devices is having a consistent view of cyber security across all of these applications. In most utilities, multiple systems and operators independently gather and analyze security information from different applications and vendors. As the threat landscape has evolved, there is a greater need to have a coordinated view of all aspects of the electric grid's security posture (situational awareness), cyber events (malicious and non-malicious) that may impact an organization's security posture, and responses to those events. To provide a consistent view across SCE's smart grid applications, all CCS nodes in the security network are displayed as circles and quadrants that represent the quality of the key security attributes shown in Figure 2. This simple perspective allows an operator to quickly identify cyber events on network connected devices, regardless of the smart grid application that is being monitored.

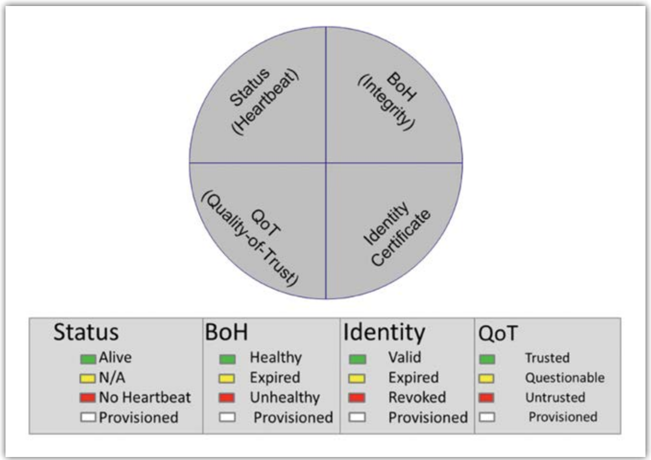


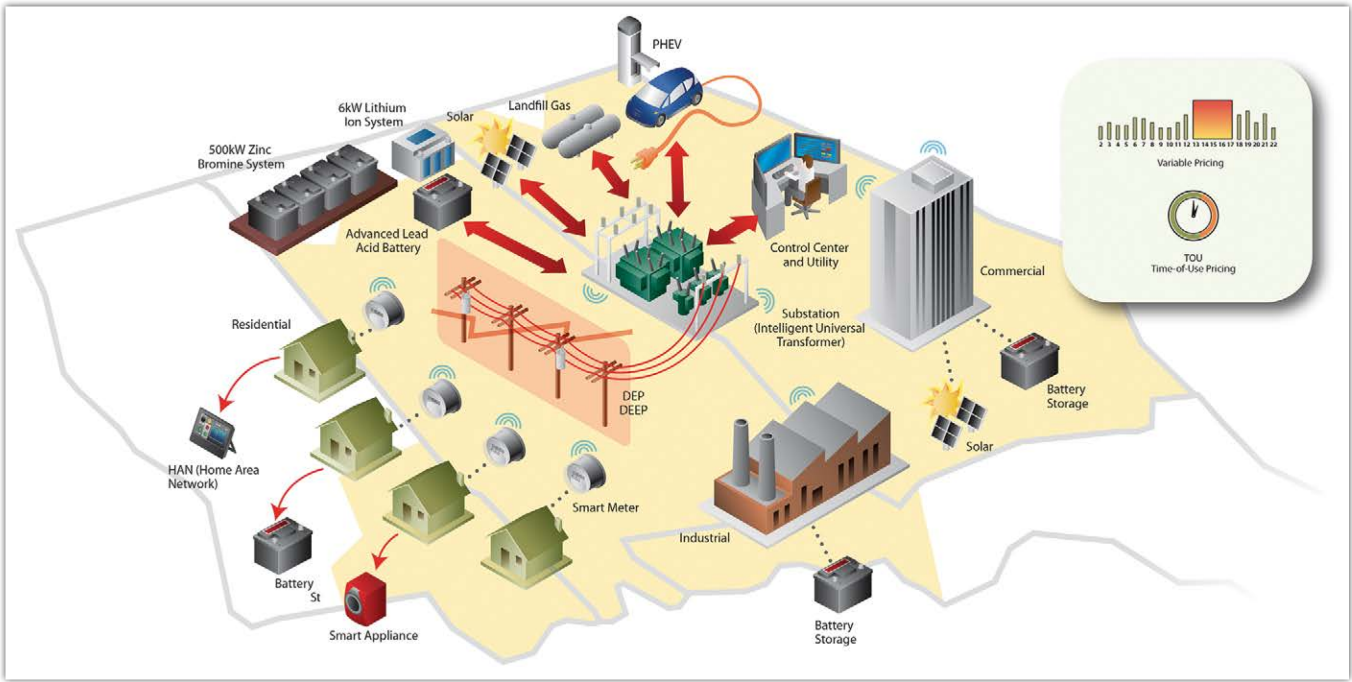
Figure 2 – CCS GUI Icon Legend

Lessons Learned

- It is critical to have a consistent view of cyber security across all applications.
- External interfaces should be protected with sophisticated boundary defenses that provide multiple layers of defense against intrusion.
- Coordinate the view of all aspects of the electric grid's security posture and response.
- A simple system perspective is needed to allow an operator to quickly identify cyber events.
- The concept of trust built into the SCE cyber security system allows for different devices with different ownership to be built into the system.
- Compliance objectives do not always align with security objectives.
- Although it is best to build in security for legacy systems from the beginning, considerable security can be obtained using a phased approach.

For the full case study, to be published in the first quarter of 2015, search www.epri.com for product number 3002004615.

Southern Company



AMI capacitor bank health monitors identified over 650 problems in the first 6 months and changed the inspection schedule from once a year to once a day.

The Southern Company Smart Grid Demonstration Project is demonstrating a comprehensive model of the smart grid featuring an integrated distribution management system, renewable energy generation, energy storage at the transformer and substation level, an intelligent universal transformer, advanced distribution operational measures, customer response to dynamic pricing, and new communications applications. These systems are being integrated across four retail operating companies: Alabama Power, Georgia Power, Gulf Power, and Mississippi Power.

A Capacitor Bank Health Monitor

Southern Company has developed and demonstrated a new automated method for monitoring the health of capacitor banks that relies on advanced meters for capturing and retrieving capacitor neutral current measurements. The new method provides timely notification of a capacitor bank malfunction.

The new capacitor bank health monitoring system replaces two traditional, time-intensive methods: 1) monthly readings of reactive power demand using VARP meters at substations, along with readings of SCADA reactive power readings (in volt amperes reactive or var), and 2) annual visual inspections of fixed capacitor banks to determine if there are any failures. Both of these methods are manual processes.

To automate monitoring of capacitor bank health, and thus improve the ability to maintain adequate var support for the distribution system, Southern Company theorized that the new Sensus advanced meter could perform the function of the VARP meter, and the AMI (advanced meter infrastructure) communications network could relay health messages back to the meter data management system (MDMS). From the MDMS, Southern Company could flag possible capacitor bank issues and send an automated message to the field technician. The field technician would then work with the line crew to visually inspect and make the required repairs to the capacitor bank. In addition, Southern Company desired to track the root cause of the capacitor bank failure to help identify any common issues associated with capacitor bank failures.

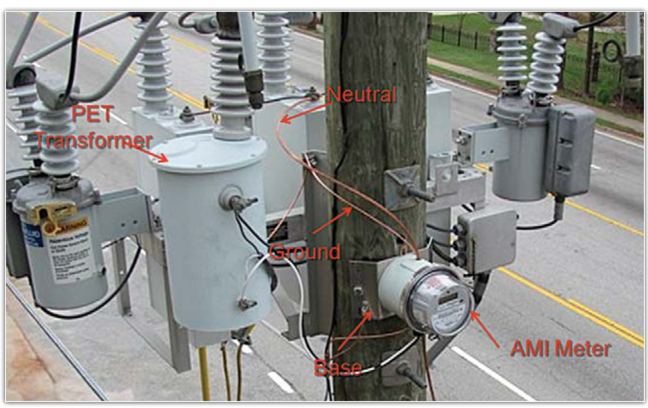
Project Hypotheses

The project was based on the following hypotheses:

- An advanced meter can be reprogrammed to monitor the health of capacitor bank installations.
- Southern Company can leverage the existing AMI network to develop a continuous monitoring system for capacitor bank health.
- An advanced meter health monitor can find capacitor bank problems that may not be recognized during annual visual inspections.
- Southern Company can determine when a capacitor bank fails by measuring the neutral current of a three-phase, grounded-wye bank.
- Over-current and kVA readings from a meter monitoring the neutral current can be used to determine a failing capacitor bank.
- Most failures are due to fuses blowing and switch malfunction.

Results

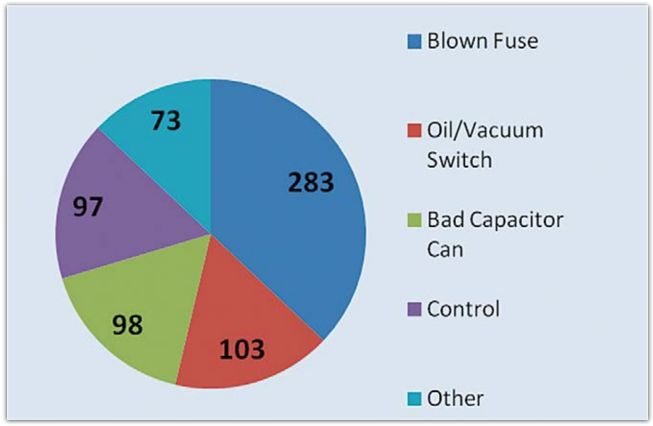
Southern Company has tested and deployed the automated capacitor bank health system, resulting in a change in the inspection schedule of distribution capacitor banks from one inspection yearly to inspections on a daily basis. The daily health check of a capacitor bank is recorded by the Southern Company advanced meter and relayed to the meter data management system through the Sensus Flexnet™ communications network. As shown in the picture below, the capacitor bank health monitor consists of a pole-mounted meter base with an embedded neutral current CT (current transformer), advanced meter, and a 120V power source.



Installation of the Advanced Meter Capacitor Bank Health Monitor

As of mid 2012, Southern Company had installed 6,400 of approximately 8,000 monitoring units on capacitor banks without SCADA communications in the service territories of Alabama Power and Georgia Power. These monitoring units have operated successfully.

An initial assessment after seven months of health monitoring showed that 624 capacitor banks were confirmed to have failed at Georgia Power and 30 at Alabama Power. The pie chart below illustrates the types of failures found by the line crews.



Issues Causing Failure of Capacitor Banks

About 10% of monitored banks were found to have failed shortly after monitors were installed. The increase in maintenance cost was supported by executives because of the reliability gains from proper operation.

Since these monitoring installations provide notification within 24 hours of failure, Southern Company has been able to make repairs to the capacitor bank within days. The expedited repairs allow Southern Company to maintain an acceptable power factor, thus reducing reactive line losses from the distribution grid back to the generator. By placing the repaired capacitor bank back on line, the system voltage can be maintained to the design circuit voltage. This helps to ensure that Southern Company achieves expected capacity benefits for a demand response volt-var optimization (VVO) program.

Lessons Learned

- To prevent erroneous readings and alarms after a problem has been resolved, the kVA (1,000 volt amperes) reading should be reset to 0 daily after it is transmitted from the meter.
- Since the voltage varies along the distribution feeder, the kVA readings would vary based on the location of the capacitor bank on the feeder. In addition, the manufacturing tolerance of the kvar (1,000 volt amperes reactive) supplied by the capacitor would cause the kVA readings to vary slightly. To address this, Southern Company found that it had to do tests and field trials to determine the best threshold values to use for each of the system voltages.
- Alabama Power originally thought they would base alarms on the neutral current reading. However, since the meter selected was a Form 2S meter, the current alarm would only be triggered if the neutral current exceeded 20 amps.

For the full case study, search www.epri.com for product number 1026447.

Southern Company

Historical SCADA data can be used to troubleshoot voltage and var imbalances. In addition, AMI meter health monitors will help identify capacitor bank issues more quickly.

The Effects of Capacitors on Substation Bus Voltage Regulated with a LTC Power Transformer

The purpose of this research was to address the adverse effects of distribution capacitors on substation bus voltage with a load-tap-changing (LTC) power transformer. Capacitors provide leading reactive power (measured in kvars) to the electric system to counteract the inductive (lagging) reactive power required by motor loads. By adding fixed and switched capacitors to the distribution system, Southern Company is able to maintain an efficient distribution grid by providing the reactive power near the end-use devices consuming this power.

However, a good practice can have its downside. Pressures to improve the efficiency of the distribution system has resulted in Southern Company adding a large number of capacitors in order to maintain a good power factor for all loading conditions. Power factor is the ratio between the real power (in watts) versus apparent power (in volt amperes) transmitted by the utility. If this added var support is not managed properly, conditions can occur that negatively impact the reliability and efficiency of the grid as well as end-use equipment.

The table below provides a basic illustration of how an unbalanced power factor can result in a voltage imbalance. For a 10.5 MVA rated power transformer with a balanced loading of 278 Amps per phase, the per unit voltage regulation (VR) across the power transformer varies dependent on the per phase power factor. In this example, the voltage difference between the phases is 3.84%. A voltage imbalance of this magnitude causes excessive heating in a three phase motor and would result in the motor having to be re-rated.

Var Imbalance Example

Phase	Load Amps	% Load	Power Factor	VR
1	278	60%	0.98 Lag	1.58%
2	278	60%	0.98 Lag	1.58%
3	278	60%	0.90 Lead	-2.26%

Hypotheses

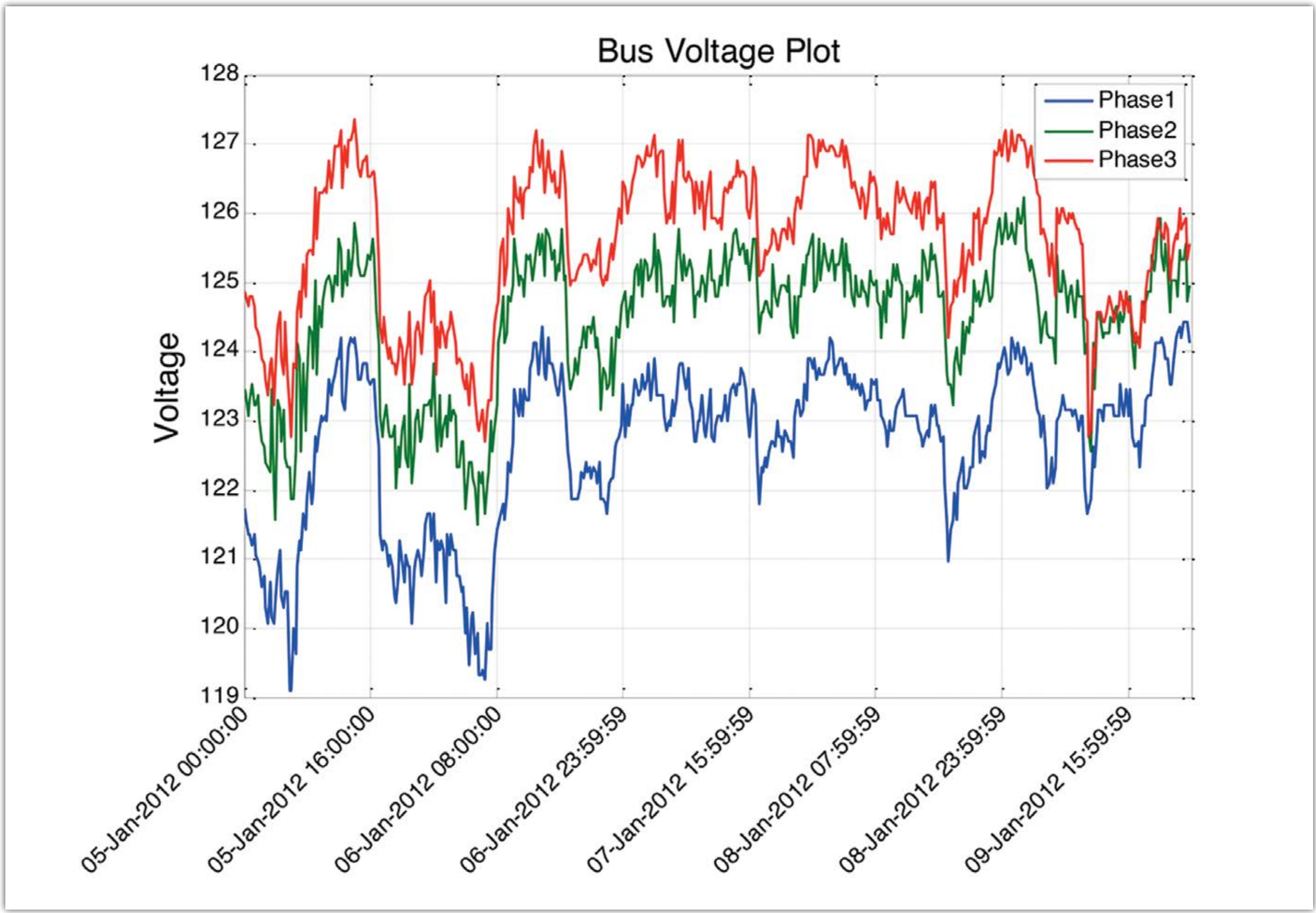
The main hypotheses tested in this project are:

- Distribution capacitor banks can cause voltage issues if units are not properly maintained.
- Capacitor bank failures lead to a voltage imbalance that results in negative impacts to the grid and end-use devices.
- Seasonal changes in substation loading compound var support issues.

Results

Recent conditions at one of the substations analyzed as part of the case study illustrate some of the problems that can occur when capacitor banks are not properly managed. In this case, the regulated 12.47 kV bus voltage was imbalanced with high voltage on two phases and low voltage on another phase as shown in the figure. After determining the substation per phase Amp readings were similar in magnitude, it was determined that phase 1, the low voltage phase, had considerably less var support than phases 2 and 3.

On 1/9/2012, a three phase 900 kV fixed capacitor bank located on one of the circuits fed from the substation was inspected. Phases 2 and 3 were found energized while phase 1 was de-energized resulting in 300 kvar imbalance. At approximately 11:00 am on 1/9/2012, the capacitors on phases 2 and 3 were de-energized. The figure above shows the bus voltage from 1/5/2012 through 1/10/2012. After de-energizing these capacitors, the voltage imbalance decreased from 3.5 Volts to approximately 1.6 Volts. Most of the remaining imbalance was attributed to imbalance in the 44 kV transmission source. Even though a var imbalance of 300 kvar is small under most operating conditions, the lightly loaded winter period with little need for var support exacerbated the voltage imbalance issue.



Substation Bus Voltage

Lessons Learned

- Capacitor banks performance needs to be monitored at all times, not just periodically.
- Small changes in var support can have adverse effects on grid efficiency, reliability, and power quality.
- Near real-time SCADA monitoring and the evaluation of historical SCADA data can be easily used to troubleshoot the adverse effects of abnormal capacitor bank operation.

Based on this case study analysis, Southern Company successfully demonstrated that historical SCADA data can be used to troubleshoot voltage and var imbalances. In addition, the installation of an AMI meter health monitor on a large number of the existing fixed capacitors bank and on all new ones will help Southern Company identify capacitor bank issues more quickly.

Moving forward, the use of near real-time SCADA data to expedite the timely identification of capacitor bank issues in conjunction with the AMI capacitor bank health monitor is critical to maintain an optimally operated and maintained distribution system.

For the full case study, please search www.epri.com for product number 3002002245.

Southern Company

Econometric (statistical) models of weather-sensitive and periodic loads can explain a large fraction of the variation in load at the substation level and can reliably predict the impacts of voltage reduction.

Peak-Time Voltage Reduction Analysis Case Study at Georgia Power – A Southern Company

Georgia Power conducted a series of peak-time voltage reduction tests during high-demand hours in 2012 and 2013. The tests and subsequent analysis were designed to determine the effectiveness of reducing load during high-demand hours by reducing the supply voltage at the substation.

The study sought to determine whether or not the CVR factor (the percentage change in power with respect to a percentage change in voltage) and the voltage reduction impacts varied over the course of the test period. Each depends on a number of conditions that would be expected to show substantial intraday variability, including end-use load mixes. A statistical model of substation load was developed, incorporating potential impact of reduced voltage, and the model was used to estimate this impact on load and energy use at the tested substations.

Testing

The tests were conducted on five substations that Georgia Power uses to test smart grid applications and devices. The 2012 tests ran from July to September. The substation voltage control equipment and the distribution line capacitor banks were activated to achieve a reduced voltage profile on alternating weekdays for a specified set of afternoon and evening hours. The specific hours varied by test day.

The 2013 tests ran from August 5 through September 5. Similar to the 2012 testing, the 2013 test activated the substation and distribution equipment on alternating days. Since the daily test window was fixed, in contrast to the 2012 test, each hour was scheduled for testing on the same number of test days, so all hours would have the same sample size. However, the shorter test period generally reduced the number of weekday voltage reduction tests.

	Weekday		Weekend	
Substation	**Avg. kV**	**% Reduction**	**Avg. kV**	**% Reduction**
Sub F	25.855	-1.9%	25.818	-1.2%
Sub M	12.799	-2.0%	12.782	-1.7%
Sub P	12.853	-3.1%	12.848	-2.9%
Sub R	25.803	-2.1%	25.774	-1.8%
Sub V	20.428	-2.9%	20.399	-2.6%
Average		-2.4%		-2.0%

The table shows average non-test day voltages and percent voltage reductions resulting from the tests at each substation for the 2013 test period. Excluding Sub F, the average percent load reduction was approximately 2% for the 2013 tests.

The load profiles for each of the five substations were typical of a residential and commercial mix of customers. Sub F had one industrial customer that accounted for roughly 70 percent of its weekday usage, and even the remaining load (difference between Sub F and the large customer) was relatively constant throughout the day, indicating that even without the large customer Sub F's load is not weather-sensitive.

Challenges and Analytical Approach

The main challenge for peak-time voltage reduction impact estimation arises from the small size of voltage reduction impacts relative to other sources of load variability. Because the voltage reduction impact is small, a sufficient amount of data is required.

Measuring a difference in means, such as the difference in loads between an interval when voltage is being reduced and an interval when it is not, requires more data when the effect is smaller—or when the variability of the data greater. However, while substation loads may be highly variable, much of the variability is predictable as a function of weather, time-of-day, or other periodic effects. To the extent a load model is able to explain a large fraction of substation load as a function of weather or periodic effects, there is less residual noise in load from which the voltage reduction impact signal must be extracted.

Two major approaches utilized in this study were the ordinary least squares (OLS) regression using screened data, and "robust" regression methods such as median regression that tend to be less susceptible to inclusion of outliers. The two approaches produced qualitatively similar results.

Results

The evaluation showed statistically significant average weekday load impacts from voltage reduction (averaged over all test hours) at four of the tested substations in the analysis of the 2012 data (all but Sub F).

Three of the four substations with statistically significant voltage reduction impacts in 2012 also had statistically significant voltage reduction impacts in the 2013 test. In 2013, Sub R data showed no significant voltage reduction impact.

The estimated weekday CVR factors, excluding Sub F, by hour and substation ranged from 0.3 to 2.0, with an overall (unweighted) average of 1.1 in 2012. For 2013, the range of the estimated CVR factors, again excluding Sub F, was -0.6 to 2.1, with an average CVR factor of 0.8.

- The range of weekday substation-level CVR factors (for the substations excluding Sub F) was 0.7-1.5 in the 2012 tests and 0.1-1.6 in the 2013 tests, with overall average CVR factors of 1.1 in 2012 and 0.7 in 2013.
- For Sub M, Sub P, and Sub V, most individual weekday test hours also exhibited statistically significant load reductions in the test hours.

The lower average CVR factor in 2013 is due in part to smaller and less statistically significant voltage reduction load impacts for Sub R, and partly due to "wrong sign" impacts estimated for hours 20 and 21 at Sub V. The graph illustrates the resulting average load impacts based on the % voltage reduction at one of the substations, Sub P, for the 2013 test period. The results for each of the hours were statistical significant.

Most of Sub F's load was due to one large industrial customer. In contrast to the other four substations, where the weather-sensitive/periodic load model performed relatively well, the model explained considerably less of the variation in Sub F's load. The large customer's usage data supplied by Georgia Power exhibited relatively little weather sensitivity and was quite variable during periods that appear to correspond to normal operations. The analysis showed no statistically significant voltage reduction impacts for Sub F in the 2012 test data, and a number of statistically significant "wrong sign" impacts in the 2013 test, using the OLS estimator.

Lessons Learned

The key lessons learned included:

- Econometric models of weather-sensitive and periodic loads can explain a large fraction of the variation in load at the substation level in many cases. For the Georgia Power tests, the exception was Sub F, where one industrial customer accounts for most of the substation load.
- With the poorer fit of the weather-sensitive model and relatively large residual variability of the large customer's load, it was not possible to obtain reasonable voltage reduction impact estimates for Sub F. The results for Sub F, compared to the other Georgia Power substations, suggests that the goodness-of-fit (R-squared) of a model of weather and periodic load effects may serve as a useful screening tool for substations where voltage reduction impacts may be difficult to measure reliably.
- After data screening, ordinary least squares (OLS) estimation methods provide similar voltage reduction impact estimates to "robust" methods used in other CVR analysis methods.
- Voltage reduction impacts were generally statistically insignificant for weekend test hours. This appears in part to be a data limitation, as weekend days were not tested in 2012, and the short 2013 test period provided limited weekend data.

For the full case study, available by the end of 2014, search www.epri.com for product number 3002004616.

Southern Company

Although substation loads are highly variable, much of the variability is predictable as a function of weather, time of day, or other periodic effects.

2013 Conservation Voltage Reduction Analysis Case Study at Alabama Power – A Southern Company

The 2013 conservation voltage reduction (CVR) evaluation at Alabama Power was undertaken to determine the impacts of CVR over the course of a day. The tests and evaluation were designed to determine the effectiveness of CVR when used primarily to reduce load during high-demand hours and when operated continuously to limit energy use as well as peak demand. A statistical (econometric) model was developed to analyze the substation loading in order to extract the small changes in the load due to the reduction in voltage.

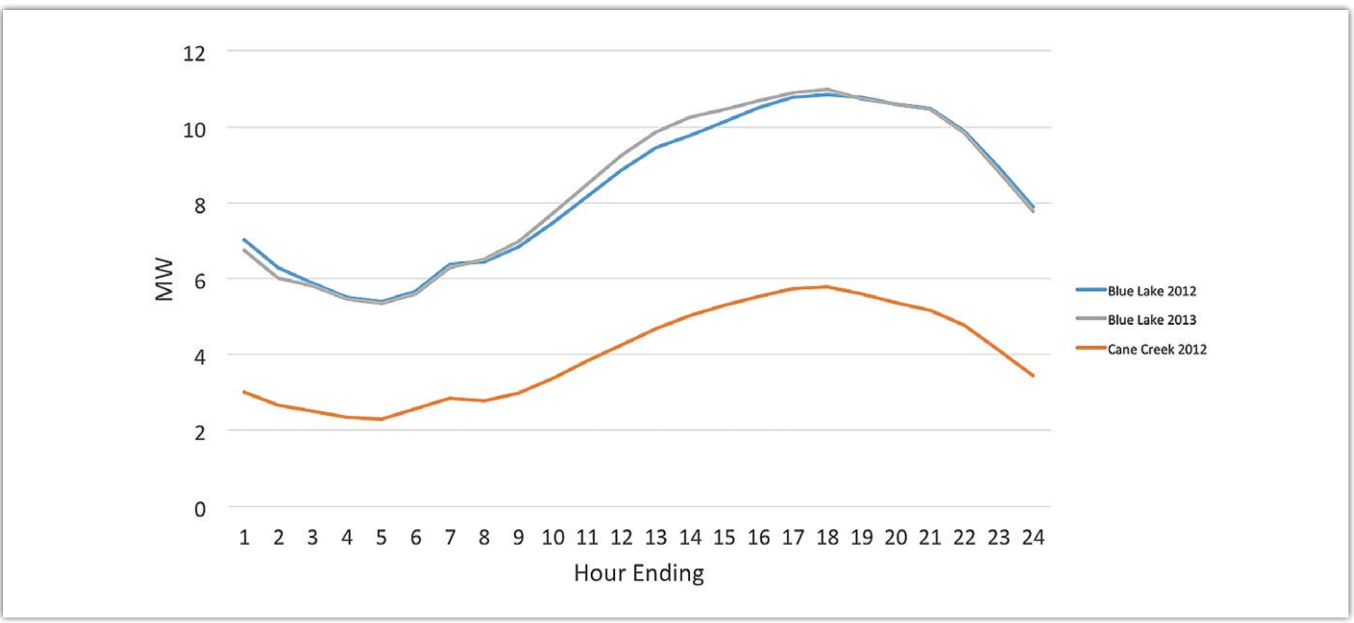
The CVR tests were conducted on two feeders. One feeder represented a typical rural feeder while the second feeder was characteristic of an urban feeder. Both feeders were subjected to a day-on/day-off test schedule. The test pattern consisted of switching the voltage, at either the feeder/line regulators for the rural feeder or the load-tap changing (LTC) transformer for the urban feeder, between a normal voltage profile (day-off) and a reduced voltage profile (day-on).

	Weekday		Weekend	
Substation	**Avg. V**	**% Reduction**	**Avg. V**	**% Reduction**
Rural Feeder 2012	124.22	-2.7%	124.30	-2.7%
Urban Feeder 2012	123.70	-3.6%	123.70	-3.5%
Urban Feeder 2013	123.55	-3.6%	123.57	-3.6%

The table shows average non-CVR voltages and percent voltage reductions for tests on weekdays and weekends at each substation for the 2012 and 2013 analysis periods. Voltage levels on the urban feeder are relatively stable across hours not affected by transitions in the CVR test state (i.e., "flatter" voltage profile). The rural feeder's voltage profile exhibits more variability, with peaks in the late evening and early morning. Both substations have line drop compensation (LDC) settings that permit the voltage to rise and fall based on the loading at the power transformer. The LDC settings were enforced on both day-on and day-off days.

Given the corresponding average voltage reductions, average weekday loads were reduced by 1.0%, 2.4%, and 1.9% for the rural, urban 2012, and urban 2013 feeders, respectively.

The graph shows the average non-CVR weekday load profile of the two feeders. Both the rural (shown as the orange line) and urban (shown as the blue line for the 2012 and gray line for the 2013 load profiles) feeders have similar load profiles that are consistent with weather-sensitive customer load patterns.



Hypotheses

The main hypotheses tested in this CVR project were:

- A model can be developed to account for CVR hourly impacts even though the impacts may be smaller than the load variations at the point of measurement.
- Weather data can be used to refine the accuracy of the CVR prediction model.

Results

Two major approaches were used to determine the CVR factor (the percentage change in power with respect to a percentage change in voltage) for each hour of the day. These were the ordinary least squares (OLS) regression using screened data, and median regression, which tended to be less susceptible to inclusion of outliers. The regression models controlled for several patterns of weather-sensitive (cooling) and non-weather sensitive periodic load components, which included cooling degree hours (CDH), a three-hour and a 24-hour moving average of CDH, and the day of the week.

The rural and urban feeders were analyzed separately using both regression methods. The results using each method produced qualitatively similar results. The estimates of weekday average CVR factors range from 0.4 to 0.7, and the weekend factors range from 0.8 to 1.3. Within weekdays, Alabama Power found larger CVR impacts in off-peak hours than in peak afternoon and evening hours. The individual hourly estimates for the CVR impact in most afternoon and evening hours for the urban feeder generally showed load reductions, but the hour-level effects mostly were not statistically significant. The daytime impacts for the rural feeder were more variable (including more "wrong sign" impacts showing an increase in load for CVR-on hours), but also statistically insignificant. These results point to the fact that hourly CVR impacts are difficult to quantify even when the test period spans a lengthy period of time. Further research is needed to determine if a separate model is needed to evaluate the effectiveness of CVR when used primarily to reduce load during high-demand hours versus continuously operated CVR.

Lessons Learned

Below are the key lessons:

1. Econometric models of weather-sensitive and periodic loads can explain a large fraction of the variation in load at the substation level, and were able to explain most of the variability of load for the tested substations.
2. Technical problems with voltage-regulating and var-support devices can cause control issues that in turn lead to data issues with the analysis. The rural feeder had one set of regulators that began to fail in September 2012. As a result, the failure led to considerable data loss.
3. After data screening, ordinary least squares (OLS) estimation methods provided CVR impact estimates that were similar to median regression estimates.
4. Statistically significant average weekday and weekend load impacts from CVR (averaged over all test hours) were found for both the rural and urban feeders during the summer periods that had sufficient data for analysis.
5. The pattern of hourly estimates showed that the CVR impacts during afternoon and evening hours tended to be statistically insignificant. Most of the urban feeder estimates showed statistically insignificant load reductions in those hours; results at the rural feeder were more mixed. Thus, it s not clear from these analyses that CVR systems can reliably deliver large load reductions in higher-load afternoon and evening hours.

For the full case study, available by the end of 2014, search www.epri.com for product number 3002004617.

Southern Company

The degradation of system power quality was negligible or non-existent during the CVR tests performed on five Georgia Power substations in the summer of 2012.

Analysis of Power Quality Impacts during Conservation Voltage Reduction (CVR) at Georgia Power – A Southern Company

Georgia Power conducted a series of voltage reduction tests during high-demand hours in 2012. The non-power quality results of the tests are documented in a separate EPRI case study entitled *2013 Conservation Voltage Reduction Case Study at Georgia Power – A Southern Company*. This case study provides details of how voltage reduction tests affected the power quality of the substations evaluated as part of this study.

Hypotheses

The main hypotheses tested in this project are:

- The use of gang operated switched capacitor banks does not significantly change the harmonic distortion on a feeder.
- Properly controlled capacitor banks enable both voltage and var optimization with limited or no degradation to the power quality of the feeder/substation during peak-demand, reduced voltage periods.

Methodology

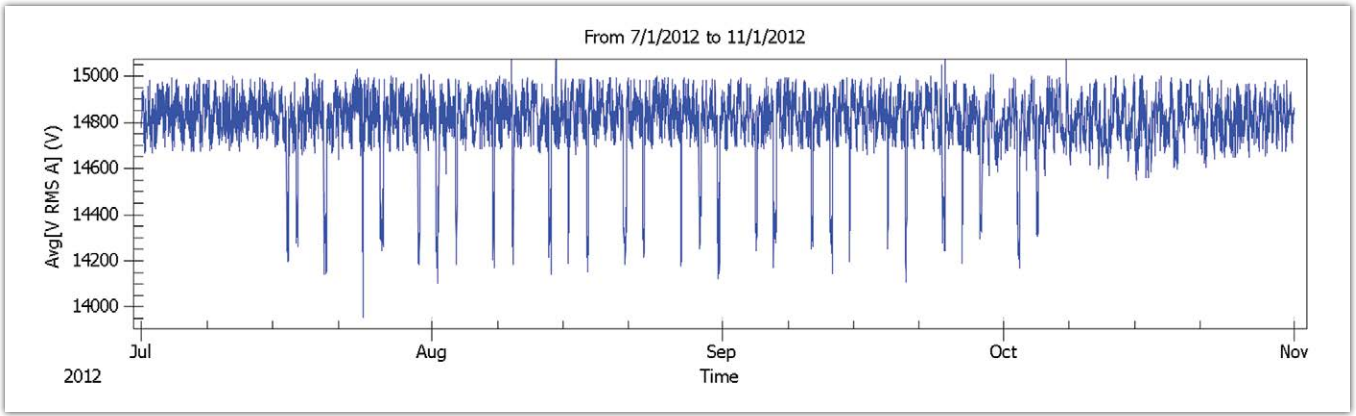
Georgia Power conducted peak-time voltage reduction tests at five substations that are representative of a typical distribution substation. A PSL PQube power quality analyzer was installed at each substation bus. On select feeders out of these test substations, Georgia Power opted to install one or more meters at key points along the distribution line. Each analyzer provided the following data for the analysis:

- Three-phase and single-phase power monitoring
- Voltage dips, swells, and interruptions
- Over-frequency and under-frequency events
- High-frequency impulse
- Harmonic distortion
- Voltage and current unbalance
- Flicker
- Event recording

The evaluation period ran from July 1st through October 31st of 2012. Voltage reduction tests were performed for a few hours each day, on an alternating schedule of Monday, Wednesday, and Friday for one week, and then Tuesday and Thursday for the next week. The graph below shows the voltage profile in Profile A, as well as the lower voltage tests periods, over this window of time.

Results

The switching of capacitor banks and the lowering of voltage had no significant impacts on power quality, supporting the hypotheses tested in this project. The reduction of voltage did approach the boundaries of voltage regulation for a few sites, but there were no reports of customer complaints during this period or loads not operating as they should.



The results averaged over the five substations for the various power quality issues tested are shown in Table 1.

Table 1		
Measurement	**Standard /Goal**	**Result (averages/findings across all measurement sites)**
Voltage reduction	Within +/- 5% (per ANSI C84.1)	Average was between 3%- 4%
Imbalance	Max. voltage imbalance limited to 3% (per ANSI C84.1)	Average below 0.5%
Distortion	Voltage total harmonic distortion (VTHD) limit = 5% (per IEEE standard 519) Total demand (current) distortion (TDD) limit = 5% - 20% depending on short circuit rating and loading at customer point of common coupling (per IEEE standard 519)	VTHD and TDD = averaged below 2%, and no significant change when transitioning into voltage reduction period
Flicker	Limit is below 1.0 PST (perceptibility short term) (per IEC 61000-3-3)	Average below 0.1, and no significant change when transitioning into voltage reduction period
Power factor	Goal is to keep power factor as close to 1.00 as possible	Average power factor of 0.99, and no significant change when transitioning into voltage reduction period
Power quality events	Goal is to minimize events to as close to zero as possible	No transient or swell events; and out of 20 sag events 2 were during voltage reduction tests

Table 2 shows the power quality statistical values for the power quality impacts during the voltage reduction tests at Georgia Power. Values for each substation and trends and distributions of parameters for each site during this measurement period are given in the full case study report to be published at the end of 2014.

Table 2		
Measurement	**Range of Mean**	**Range of Max**
Sustained Voltage Drop	2% to 4%	4% to 6%
Voltage Imbalance	0.25% to 0.45%	0.5% to 0.95%
Voltage Total Harmonic Distortion (VTHD)*	0.9% to 1.5%	1.1% to 1.8%
Total Demand Distortion (TDD)*	1.1% to 2.5%	1.4% to 3.2%
Sustained Perceptibility Short-term (PST) Flicker	0.05% to 0.07%	0.16% to 0.45%
Power Factor	0.98 to 0.99	0.75 o 0.96

* *Excludes results from one substation with a large industrial customer.*

Unresolved Questions

This analysis did not include an assessment of the power quality impacts on customer loads. Theoretically, with nominal voltage at a lower value, such loads could have increased sag susceptibility. Future testing in a laboratory environment may help test this theory.

For the full case study, available by the end of 2014, search www.epri.com for product number 3002004620.

Southern Company

Southern Company avoided approximately 46 million outage minutes with its self-healing networks from first quarter 2012 until first quarter of 2014

Self-Healing Networks at Southern Company

Over the past two years, Southern Company has deployed more than 325 self-healing networks on roughly 700 circuits serving more than half a million customers. These self-healing networks automatically reconfigure after an outage to restore power to as many customers as possible. This case study describes these networks, their technology, and their effect on reliability.

Self-Healing Network Operation and Technology

The basic self-healing network installation at Southern Company is shown in Figure 1. It has one automated normally-closed switching device on each of two conjoining circuits tied together with an automated normally-open switching device. Here's how it works: When a fault occurs within Segment A, the breaker at Source 1 opens to clear the fault. The self-healing network controller senses the opening of the breaker and determines that there was no fault in Segment B based on device #1 remaining closed. As a result, device #1 is opened and device #3 is closed to restore service to the customers in Segment B from Source 2. The same logic can be applied in the event that a fault occurs in Segment D. In this case, service would be restored to Segment C from Source 1 after the self-healing network reconfiguration.

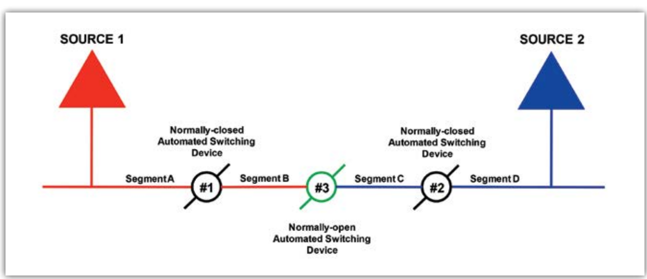


Figure 1 – Basic self-healing network

The approach to self-healing deployments has morphed within Southern Company over the past 15-20 years with advancements in distribution equipment technologies. The initial self-healing networks utilized automated gang operated switches as the self-healing switching devices. In many cases, existing manually operated gang switches were retrofitted with a motor, controller, instrument transformers (potential and current transformers), and communication equipment to permit remote opening and closing of the switch. As technology advanced, the sensing and control equipment were packaged together with the switch as a complete unit. Today, Southern Company uses a mixture of automated switches, reclosers, and substation breakers as self-healing network devices. Figure 2 shows examples of the switching devices used in the Southern Company self-healing networks.

Centralized and Decentralized Self Healing Networks

Southern Company has two types of self-healing network control systems: decentralized and centralized. The decentralized control system utilizes peer-to-peer communications via 900 MHz unlicensed spread spectrum radios and in some cases via cellular communications. The switching devices communicate with one another to determine the status and real time loading data of the devices in the scheme. Based on pre-defined thermal limits, functional roles, and other parameters assigned to each device, the distributed intelligence shared between the devices permits the identification and isolation of the fault and the optimal reconfiguration solution. The circuit reconfiguration can happen as fast as 10 cycles but may take as long as 90 seconds based on the complexity and criticality of the decentralized scheme.

The Southern Company centralized self-healing control systems run in parallel with the SCADA system. SCADA data, such as position of switching devices, voltage and current readings, and fault indication, are processed by the controller in order to reach an optimal solution for isolating the fault and restoring power. The centralized controller monitors the load of the system segments to ensure that the circuit reconfiguration does not exceed any thermal limits of the equipment and the conductors during an event.

The real-time load monitoring feature of the centralized system provides an advantage over the decentralized system that uses predefined static load thresholds. In addition, the centralized controller provides a graphical display of the system as configured for operations. The centralized controller can control up to 100 devices per scheme and permits the inclusion of substation breakers into the scheme. The centralized systems currently in use today, as well as the ones planned for the future, reconfigure the system in less than five minutes.

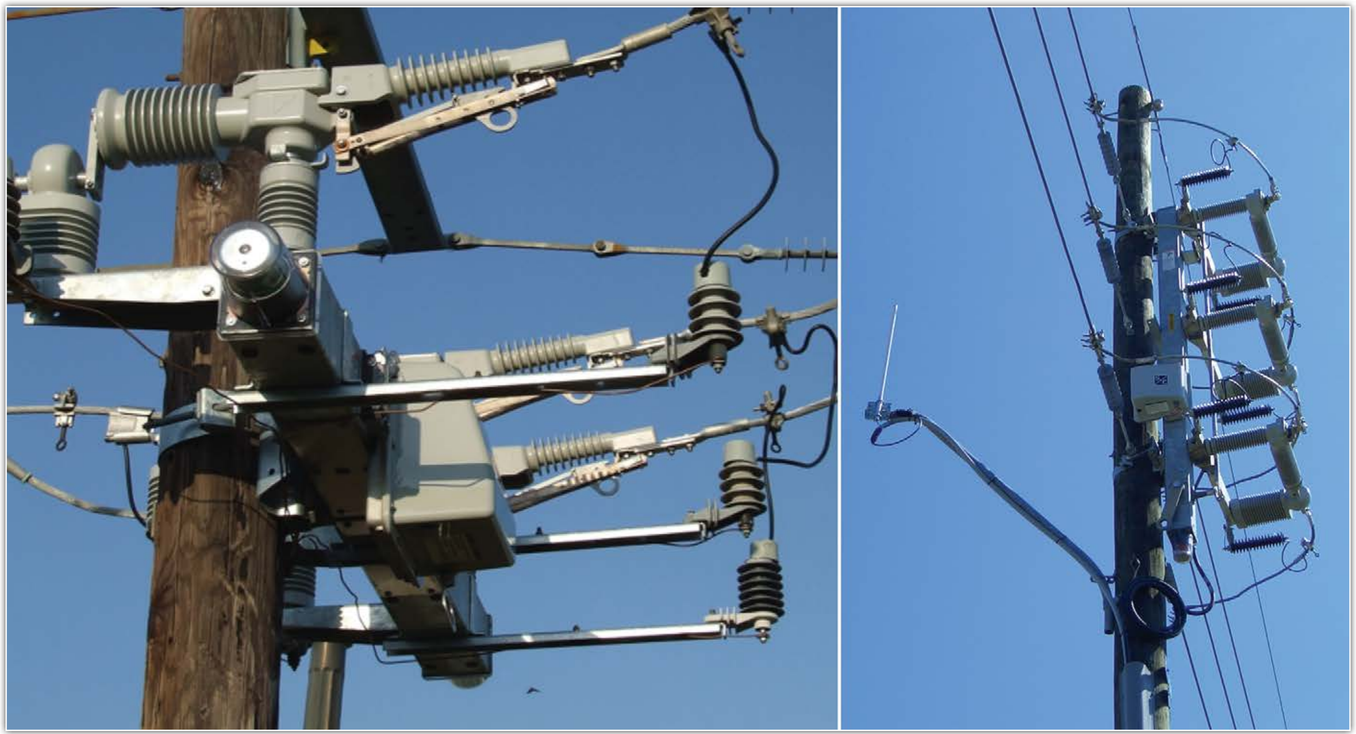


Figure 2 – Self-helaing network devices

Results

Through the first quarter in 2014, the self-healing networks deployed as part of Southern Company's smart grid demonstration operated successfully almost 800 times. As a result, more than 630,000 customers had their service automatically restored within a few minutes. As of the first quarter of 2014, Southern Company estimates that these self-healing networks spared its customers 46 million minutes without power.

Lessons Learned and Key Recommendations

- Utilities should be open to utilizing different technologies in the self-healing networks. As technologies improve, utilities' standard schemes should be sufficiently flexible to enable incorporation of new devices that have the potential for greater reliability and less ongoing maintenance.
- Utilities need to have a structured approach to installing self-healing networks. Prioritize feeders that provide the highest potential to improve circuit and system reliability. Plan for all present and future contingencies based on estimated load growth of the circuits included in the self-healing network.
- Distribution planning and design criteria should be modified to incorporate self-healing network design requirements, such as conductor load carrying capability and the installation and location of the automated switching devices.
- Due to the sheer volume of devices being installed that require communications, the Southern Company IT department reorganized to form a dedicated workgroup to install and maintain communications to both transmission and distribution devices. This partnership between the Operations, Engineering and IT workgroups led to increased utility operational efficiency and is recommended to other utilities embarking on a project of similar type and scale.

Next Steps

Southern Company plans to continue the installation of self-healing networks. The integrated distribution management systems being deployed will provide another platform for centralized systems. In addition, Southern Company plans to continue testing and deploying new distribution line equipment and communications options, such as cellular communications, for inclusion in future self-healing network schemes.

For the full case study, available by the end of 2014, search www.epri.com for product number 3002004621.

The EPRI Smart Grid Demonstration Initiative Team

GALE HORST

Gale Horst is a Senior Project Manager at EPRI and manages several Smart Grid Demonstration Projects. With a focus on integrating distributed energy resources, Gale has been involved in NIST/PAP standards development. He also directed consumer engagement research related to consumer values, motivations, and acceptance of grid modernization technologies. Prior to joining EPRI, Gale led energy research at Whirlpool Corporation, which has resulted in four energy management patents.

MATT WAKEFIELD

Matt Wakefield is Director of the Information and Communications Technology group at the Electric Power Research Institute (EPRI), managing Smart Grid, IntelliGrid and Cyber Security Programs. He has more than 25 years of energy industry experience with a strong emphasis on applying information and communication technologies for real-time information transfer between control centers, generators, markets and consumers. He received his BS degree in Technology Management from the University of Maryland University College.

JOHN SIMMINS, PHD

John Simmins is a Technical Executive at EPRI and manages several Smart Grid Demonstration Projects as well as the IntelliGrid distribution program. John is involved in the UCA, IEC TC57-WG 14, OpenSG and holds several positions within the NIST SGIP effort. He has a BS and a PhD in Engineering and is a member of IEEE, GITA and the Project Management Institute.

JEFF ROARK

Jeff Roark is a Senior Project Manager at EPRI, and is engaged in cost-benefit analysis and training for the Smart Grid Demonstration Initiative. Jeff has 35 years experience in the electric utility industry in all phases of system and strategic planning, as well as market analysis. He holds BS and MS degrees in Electrical Engineering from Auburn University, and an MBA from the University of Alabama in Birmingham.

JARED GREEN

Jared Green is a Project Manager for the Smart Grid Demonstration Initiative at EPRI. Jared is involved in managing four host-site Smart Grid Demonstration Projects. He is also directly involved in distribution equipment and advanced applications research. He has a BS in Electrical Engineering and is a registered Professional Engineer and Certified Carbon & GHG Reduction Manager.

CHRISTINA HUFF

Christine Huff is a Project Engineer/ Scientist in the Smart Grid Demonstration Initiative in the Power Delivery and Utilization Sector at EPRI. Her research for the Initiative has included cost-benefit analyses of projects. Ms. Huff received a BS degree in International Politics and Economics and a MS degree in Environmental Planning from the University of Tennessee, Knoxville.

PAT BROWN

Pat Brown is a Senior Project Manager with EPRI, and has spent over 25 years supporting electric utility control center applications. In 2013 she began managing the Kansas City Power & Light demonstration project for EPRI. Pat also is part of EPRI's IntelliGrid program, and focuses on leveraging industry standards, including the Common Information Model (CIM), in the deployment of data sharing solutions for transmission. She has a BS in Architecture from the University of Michigan and is a certified Project Management Professional.

ROBIN PITTS

Robin Pitts is a Senior Administrative Assistant with EPRI, supporting Matt Wakefield, Director, for Smart Grid, IntelliGrid and Cyber Security Programs. Within EPRI's Power Delivery and Utilization group, Robin has supported these programs for 7 years with contracts, departmental budgets, event coordination and professional administrative resources.

GERALD R. GRAY, PHD

Gerald R. Gray is a Technical Executive with EPRI and specializes in utility enterprise architecture and integration. In 2013 Gerald began managing the Ergon Energy demonstration project. He also is part of the IntelliGrid team, and has been involved in the development of numerous industry standards such as IEC CIM, MultiSpeak, SAE, and OASIS EMIX and Energy-Interop. He has a BS in Management/CIS from Park University, an MIS from the University of Montana and a PhD in Organization and Management from Capella University.

Index

Ameren 4-5
American Electric Power (AEP).......... 6-11
Advanced metering infrastructure (AMI) 28-29, 32-33, 54-55, 58-59, 74-75, 86-87
Alabama Power.......... 86-87, 92-93
Aggregation.......... 12-13, 14-15, 16-17, 22-23, 36-37, 40-41
Ancillary services 16-17
Australia 24-25
Automated demand response (ADR).......... 2-3, 58-59, 72-73
Battery storage 6-7, 14-15, 44-45, 60-61, 62-63
Building control and energy management 16-17, 34-35, 62-63
Capacitor bank 36-37, 38-39, 46-47, 48-49, 64-65, 80-81, 86-87, 88-89, 90-91, 94-95
Commonwealth Edison.......... 32-33
Communication systems.......... 4-5, 18-19, 20-21, 26-27, 28-29, 36-37, 54-55, 78-79, 82-83, 86-87, 96-97
Conservation voltage reduction.......... 4-5, 8-9, 14-15, 26-27, 64-65, 68-69, 90-91, 92-93, 94-95
Consolidated Edison.......... 12-17
Cost-benefit.......... 2-3, 26-27, 78-79
Cross-utilization 8-9, 10-11
Customer behavior 24-25, 28-29, 32-33, 40-41, 54-55, 56-57, 66-67, 70-71, 72-73, 74-75, 76-77
Cyber security 84-85
Defer/delay investment in infrastructure 14-15, 24-25, 36-37
Demand response 12-13, 14-15, 16-17, 32-33, 34-35, 40-41, 58-59, 72-73
Direct load control (DLC) 24-25, 36-37, 38-39, 40-41, 66-67, 76-77
Distributed energy resource (DER).......... 8-9, 10-11, 14-15, 20-21, 22-23, 24-25, 36-37, 58-59, 62-63
Distributed energy resource management system (DERMS).......... 20-21, 58-59, 62-63
Distribution management system (DMS).......... 18-19, 58-59
Duke Energy.......... 18-21
Electricité de France.......... 22-23
Electricity market 12-13, 34-35, 40-41, 60-61
Ergon Energy.......... 24-25
ESB Networks 26-31
Exelon.......... 32-37
Field area network.......... 78-79
FirstEnergy.......... 36-43
France.......... 22-23
Georgia Power.......... 86-87, 90-91, 94-95

Hawaiian Electric Company 44-45
Hydro-Québec 46-53
In-home display........ 24-25, 28-29, 32-33, 54-55, 56-57, 70-71
Inverter 2-3, 20-21, 30-31, 42-43, 44-45
Ireland 26-31
Islanding........ 20-21, 44-45, 46-47, 50-51, 62-63
Jersey Central Power & Light Company (JCP&L)........ 36-43
Kansas City Power & Light........ 54-59
Maui Electric 44-45
Microgrid 20-21, 62-63
OpenDSS........ 6-7, 42-43
PECO 34-35
Peak demand reduction........ 4-5, 6-7, 8-9, 24-25, 28-29, 64-65, 66-67, 76-77
Peak shift 28-29, 36-37, 60-61
Photovoltaics 14-15, 20-21, 24-25, 60-61, 62-63
Power quality........ 44-45, 48-49, 52-53, 88-89
Pricing........ 32-33, 66-67, 70-71, 72-73, 76-77
Protection........ 20-21, 26-27, 44-45, 46-47, 50-51, 82-83
Public Service Company New Mexico........ 60-63
Revenue protection 74-75
Sacramento Municipal Utility District (SMUD) 64-77
Self-healing networks 18-19, 26-27, 96-97
Smart green circuits........ 26-27
Southern California Edison 80-85
Southern Company........ 86-97
Standards 2-3, 48-49, 58-59, 82-83, 94-95
Time-of-use (TOU) rates 28-29, 56-57, 66-67, 70-71, 72-73, 76-77
Thermal energy storage 16-17, 36-37
Thermostat 56-57, 76-77
Substation automation 82-83
Virtual power plant 10-11, 12-13, 22-23
Visualization 38-39
Volt-var control/optimization 4-5, 8-9, 30-31, 48-49, 64-65
Voltage smoothing........ 60-61, 62-63
Wind generation 30-31, 50-51, 52-53

The Electric Power Research Institute, Inc.
(EPRI, www.epri.com) conducts research and development relating to the generation, delivery and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, affordability, health, safety and the environment. EPRI also provides technology, policy and economic analyses to drive long-range research and development planning, and supports research in emerging technologies. EPRI's members represent approximately 90 percent of the electricity generated and delivered in the United States, and international participation extends to more than 30 countries. EPRI's principal offices and laboratories are located in Palo Alto, Calif.; Charlotte, N.C.; Knoxville, Tenn.; and Lenox, Mass.

Printed on recycled paper in the United States of America

3002004652

3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com