Steven L. Beshear
Governor

Leonard K. Peters
Secretary
Energy and Environment Cabinet

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David L. Armstrong
Chairman

James W. Gardner
Vice Chairman

Linda Breathitt
Commissioner

October 11, 2013

PARTIES OF RECORD

RE: Case No. 2012-00428
CONSIDERATION OF THE IMPLEMENTATION OF SMART GRID AND SMART METER TECHNOLOGIES

Enclosed please find a memorandum that has been filed in the record of the above referenced case for the Informal Conference held on October 10, 2013. Any comments regarding this memorandum's content should be submitted to the Commission within five days of the receipt of this letter. Questions regarding this memorandum should be directed to Aaron Greenwell at 502-782-2563.

Sincerely,

Jeff Derouen
Executive Director

Attachments

INTRA-AGENCY MEMORANDUM

KENTUCKY PUBLIC SERVICE COMMISSION

TO: Main Case File - Case No. 2012-00428
CONSIDERATION OF THE IMPLEMENTATION OF SMART GRID AND SMART METER TECHNOLOGIES

FROM: Aaron Greenwell, Team Leader

DATE: October 11, 2013

SUBJECT: Informal Conference, October 10, 2013

Pursuant to Commission order, an informal conference ("IC") was held on October 10, 2013. A copy of the IC attendance list, including those who participated by phone, is attached. The IC began with brief introductions and comments by Vice Chairman Jim Gardner. Power Point presentations were then made by a representative of the Electric Power Research Institute ("EPRI") and by two representatives of the Cooperative Research Network. Copies of those presentations were made part of the record in this case on October 8, 2013 and October 9, 2013. A copy of an EPRI report entitled *EPRI Smart Grid Demonstration Initiative I 5 Year Update* was provided at the IC and is attached to this memo.

The IC concluded with Commission Staff explaining that a memo summarizing the IC will be issued for comments by all parties. The IC was then adjourned.

Attachments: Sign In Sheets
EPRI Report

ADMINISTRATIVE CASE NO. 2012-00428, SMART GRID
INFORMAL CONFERENCE
Thursday, October 10, 2013

NAME	REPRESENTING
Allyson Sturgeon	LG&E KU
David Huff	LGE KU
[illegible]	LGE - KU
Rick Lovekamp	LG&E KU
Don Harris	LGE-KU
Matt Wakefield	EPRI
[illegible]	NRECA
Doug Lambert	NRECA
John Newland	Kenergy
Derrick Dean	Jackson Energy
Ricky Caudill	Jackson Energy
Nick Morris	Jackson Energy
[illegible]	Shelby Energy
[illegible]	[illegible]
Dennis Holt	South KY
[illegible]	EKPC
Mark Stallons	Owen Electric
Jason Mann	Shelby Energy

ADMINISTRATIVE CASE NO. 2012-00428, SMART GRID
INFORMAL CONFERENCE
Thursday, October 10, 2013

NAME	REPRESENTING
Aaron Greenwell	PSC
Matt Wakefield	EPRI
Andrew Cotter	CRN
Doug Lambert	CRN
Allyson Sturgeon	LG+E & KU
David Huff	LGE & KU
John P. Malloy	LGE - KU
Rick Lovekamp	LG&E - KU
Don Harris	LGE-KU
Aaron Ann Cole	PSC-
Leah Faulkner	PSC-FA
Iris Skidmore	CAC
RICHARD RAFF	PSC-LEGAL
JIM GARDNER	PSC

ADMINISTRATIVE CASE NO. 2012-00428, SMART GRID
INFORMAL CONFERENCE
Thursday, October 10, 2013

NAME	REPRESENTING
Duncan Crosby	LGE-KU
JOHN SHUPP	PSC-ENG.
Erol K Wagner	PSC-FA
Lila P Munsey	Kentucky Power Co.
Quang D Nguyen	PSC
JEFF SHAW	PSC - FA
THE FOLLOWING BY PHONE:	
JUSTIN BROWN	DUKE KY
EVAN SHEARER	DUKE KY
JIM JACOBUS	INTER CO.
DAVID PHELPS	INTER CO.
BILL PRATHER	FARMERS
TONY WELLS	FARMERS
MIKE FRENCH	MEADE CO.
MARK ABNER	CUMBERLAND VALLEY
ROBERT TOLLIVER	CUMBERLAND VALLEY
RUSS POGUE	BIG RIVERS

HEARING SIGN IN SHEET

Hearing :	Smart Grid
Case number :	2012-00428
Location :	Hearing Rm 1
Date :	10-10-13

NAME	COMPANY
Roger Hickman	Big Rivers Electric
Ken Cooper	Blue Grass Energy
Scott S. Lowd	Clark Energy Coop
Iris Skidmore	CAC
Glenn Jennings	Delta Natural Gas
Lila Munsey	Kentucky Power Co.
Duncan Crosby	SKO for LGE-KU

ELECTRIC POWER RESEARCH INSTITUTE

EPRI Smart Grid Demonstration Initiative | 5 Year Update

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.

Table of Contents

The Smart Grid Demonstration Initiative 5-Year Update

Since its inception over five years ago, utilities participating in the Initiative have completed multiple field projects that are at the vanguard of smart grid development, and are helping to define state-of-the-art practices for building a smarter grid. This international collaboration allows us to tap into world-class expertise and experience and share results that can benefit a wide variety of smart grid projects in conducting tasks ranging from project planning, implementation, to cost benefit analysis.

In this five-year update, we are pleased to share additional lessons learned from research being conducted by members of the collaborative, in the form of case study briefs that summarize specific results of research projects. The case study briefs highlight projects conducted by 8 of 24 participating utilities. A spectrum of topics are covered, ranging from conservation voltage reduction to managing circuits with a high penetration of photovoltaic resources to determining how multiple smart grid technologies will interact.

Examples of case study results include insights into how seasonal loads can affect conservation voltage reduction; how to obtain real-time information on when capacitor banks are failing; and how an autoground approach can be used for anti-islanding protection of distributed generation.

The complete case studies are being published in 2013 and will be available to collaborating member utilities as individual reports and in a compendium format. At the discretion of member utilities, selected case studies may be made available to the public. A few case studies and Initiative reports published in the last year are already available to the public at no cost; as indicated in the back of this document. This includes the 4-Year Update (EPRI product 1025781), which features 13 case study summaries produced by 10 of the Initiative utility members in 2012.

In this update we also identify technical reports and other publications that have been delivered as part of the Initiative at the five-year mark. This year they are organized by topic for easier reference. Among the documents listed are EPRI-developed studies on member-selected "strategic topics" related to research in the demonstrations . Strategic topics in 2012 were focused on distribution management systems and integration along with cyber security for field equipment. The strategic topics in 2013 include distributed energy resource (DER) architectures, high penetration of DER on distribution systems, and measurement and verification of conservation voltage reduction (CVR) and volt-var optimization (VVO).

The 200+ deliverables that have been produced contributed to the second edition (December 2012) of the Smart Grid Reference Guide to Integration of Distributed Energy Resources (EPRI product 1025763). This is an extensive reference to smart grid project activities and results; it is the primary deliverable of the Initiative and is updated annually.

We are proud to report on the progress being made in the Initiative. On behalf of the electric utility members and EPRI technical staff, we invite you to learn more about smart grid research results.

Sincerely,

Matt Wakefield
Director, Information Communications & Technology

Gale Horst
Sr. Project Manager, Smart Grid

Collaboration across Demonstrations: Building the Knowledge to Build the Smart Grid

Twenty-four collaborating and host utilities have been designing and implementing demonstrations of smart grid technology and applications since 2008 as part of the EPRI Smart Grid Initiative. The matrix on the following page lists host-site utilities and identifies the high-level smart-grid applications they are investigating that are aligned with the goals of the Initiative.

Research for EPRI has been conducted primarily by "host" utilities, which are doing most of the field projects. Utilities also participate in the Initiative as "collaborators." These non-host utilities benefit from the knowledge gained from the demonstrations without the cost of deploying capital intensive projects, while the host utilities benefit from research performed specifically on their projects. Non-host collaborators may also conduct targeted research, in the form of "mini-demos" that relate to at least one of the research goals of the Initiative.

The additional collaborating utilities in the EPRI Smart Grid Demonstration Initiative are:

- Ameren
- Central Hudson Gas & Electric
- CenterPoint Energy
- Entergy
- Salt River Project
- Tennessee Valley Authority
- Tokyo Electric Power Company
- Wisconsin Public Service

This update highlights results of several host-site projects, as well as lessons learned from "mini-demos" conducted by collaborating utilities Ameren and Salt River Project.

Host-utilities with case study briefs in this update:

- American Electric Power
- FirstEnergy
- Hydro-Québec
- Public Service of New Mexico
- Sacramento Municipal Utility District
- Southern Company

As the matrix and the case study briefs illustrate, a wide variety of research and demonstration projects are being conducted as part of the Initiative. No single project or demonstration can provide the answers to every research question, but by collaborating across multiple projects, collective knowledge can be built, enhancing the ability of participating utilities to create the Smart Grid.

	Primary Integrated Technologies & Applications	Host Site Collaborators: American Electric Power	Con Edison	Duke Energy	Electricité de France	Ergon	ESB Networks	Exelon (ComEd/ PECO)	First Energy	Hawaiian Electric Company	Hydro Québec	Kansas City Power & Light	PNM Resources	Sacramento Municipal Utility District	Southern California Edison	Southern Company
Distributed Energy Resources	Demand Response Technologies	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■
Distributed Energy Resources	Electric Vehicles	■		■		■	■			■	■	■		■	■	■
Distributed Energy Resources	Thermal Energy Storage	■			■	■	■	■	■		■	■	■			
Distributed Energy Resources	Electric Storage <= 100 kWh	■	■	■	■	■		■	■	■	■		■	■	■	■
Distributed Energy Resources	Electric Storage >100 kWh	■		■		■			■	■		■	■	■	■	■
Distributed Energy Resources	Solar Photovoltaic	■		■	■	■		■		■	■	■	■	■	■	■
Distributed Energy Resources	Wind Generation						■	■		■						
Distributed Energy Resources	Distributed Generation	■	■		■	■		■			■	■	■	■		
Communications and Standards	**Customer Domain** (SEP, WiFi...)	■	■	■			■	■			■	■	■	■	■	■
Communications and Standards	**Distribution** (DNP3, IEC 61850...)	■	■	■		■	■	■	■	■	■	■	■	■	■	■
Communications and Standards	**Enterprise** (CIM, MultiSpeak, OpenADR...)	■	■			■	■	■		■	■	■	■	■		■
Communications and Standards	Cyber Security		■	■	■	■	■	■		■	■		■	■	■	■
Communications and Standards	AMI or AMR	■		■		■	■	■		■	■	■	■	■		■
Communications and Standards	RF Mesh or Tower	■				■	■	■	■	■	■	■		■	■	■
Communications and Standards	Public or Private Internet		■	■	■	■	■	■			■	■	■	■	■	■
Communications and Standards	**Cellular 3G** (GPRS, CDMA...)	■		■		■	■		■	■		■	■	■	■	■
Communications and Standards	**Cellular 4G** (WiMAX, LTE...)			■		■					■				■	
Grid Management	CVR/VVO	■		■		■	■		■	■	■	■		■	■	■
Grid Management	Distribution Automation	■	■	■		■			■	■	■	■		■		■
Grid Management	**Grid Management System** (DMS, DERMS, DRMS)	■	■	■					■	■	■	■		■		■
Programs	**Price Based** (TOU, CPP, RTP...)	■		■		■	■	■	■			■	■	■	■	■
Programs	**Incentive Based** (DLC, Interruptible...)	■	■		■	■	■	■	■	■	■	■	■	■	■	■
Ops & Planning	System Operations Integration	■	■	■		■	■	■	■	■	■	■	■	■	■	■
Ops & Planning	System Planning Integration	■	■	■	■	■	■		■	■	■		■	■	■	■
Ops & Planning	Modeling and/or Simulation Tools	■	■	■	■		■		■	■	■		■	■	■	■
State of Deployment	Planning					●				●					●	
State of Deployment	Deploying	●	●							●		●			●	
State of Deployment	Data Collection	●	●	●					●		●	●	●	●		●
State of Deployment	Analysis		●	●			●	●	●		●		●	●		●
State of Deployment	Complete				●											

■ Technologies and applications integrated in the demonstration

● Demonstration "state of deployment" in mid-2013

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

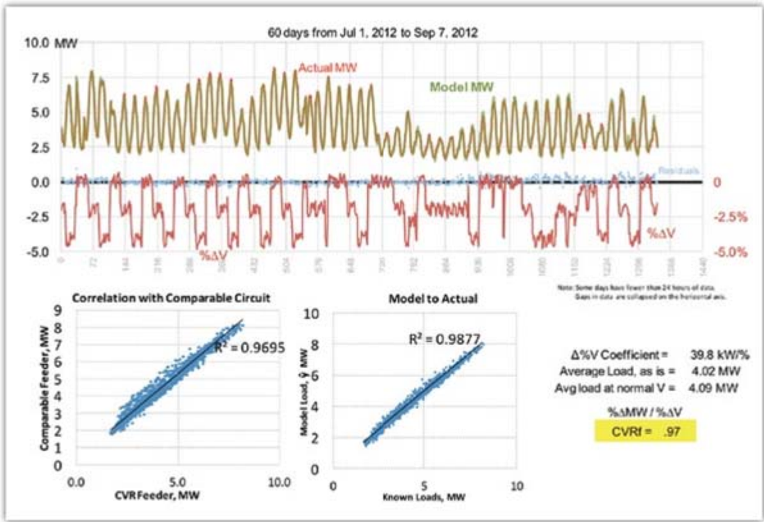
The key project hypothesis being tested is that demand is reduced and energy savings increased as the normal voltage is reduced by 2-4%.

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.

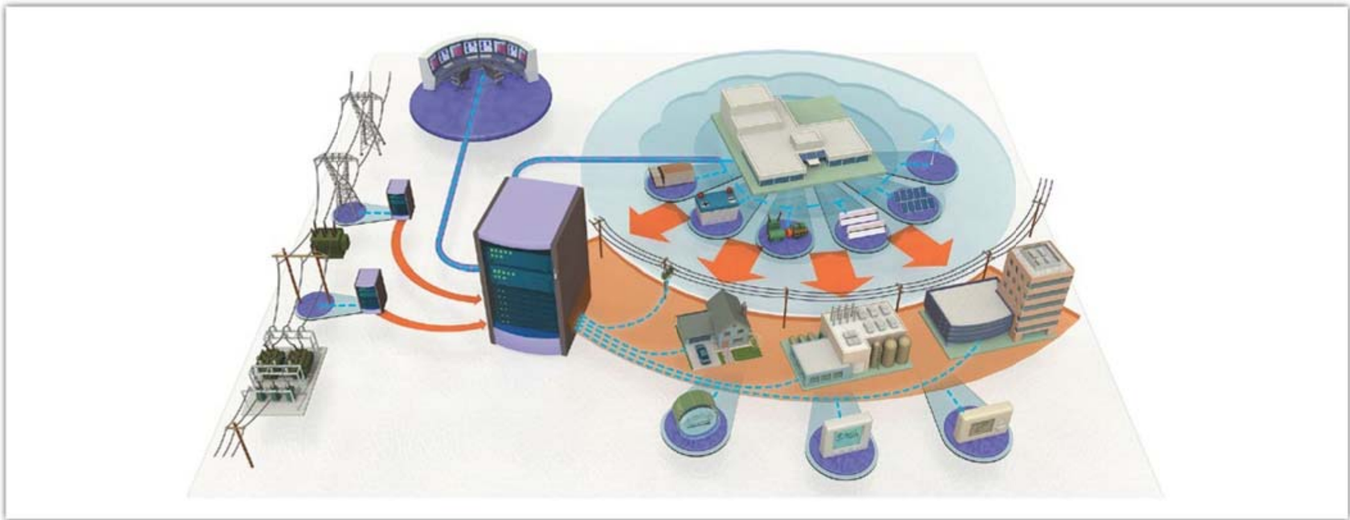
While the comparable feeders were highly correlated with the CVR feeders during the summer months, the correlation deteriorated in the fall months. The trouble was traced to several agricultural loads that became active in late summer, running sporadically during the fall. At their peaks, they were individually 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.

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.

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.

AEP 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

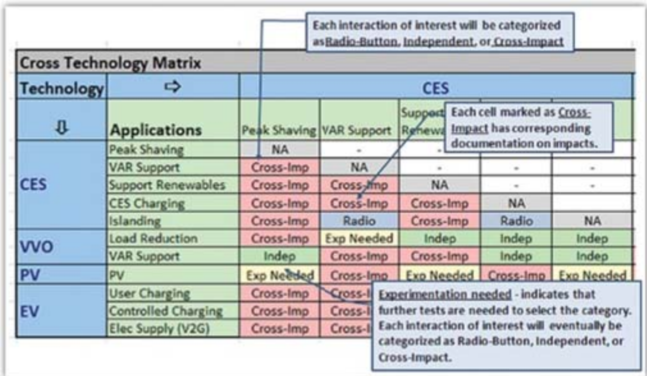
Two key spreadsheets were developed as tools to support the process, a Technologies Controls Matrix and a Cross Technology Matrix:

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.

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

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			

Each interaction of interest will be categorized as Radio-Button, Independent, or Cross-Impact

Each cell marked as Cross-Impact has corresponding documentation on impacts.

Experimentation needed - indicates that further tests are needed to select the category. Each interaction of interest will eventually be categorized as Radio-Button, Independent, or Cross-Impact.

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.

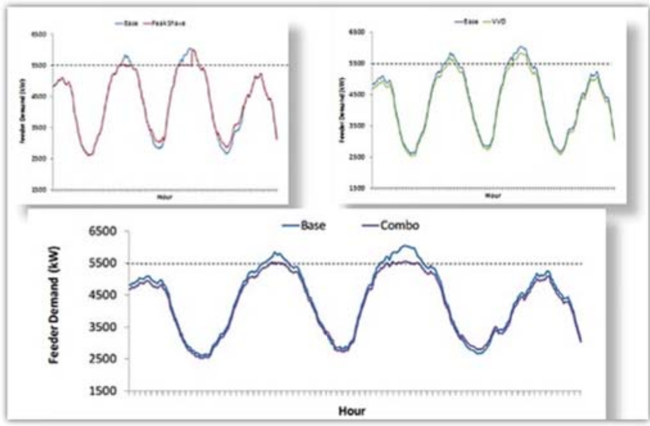


Figure 3: Cross technology operation – demand response over 3-day period

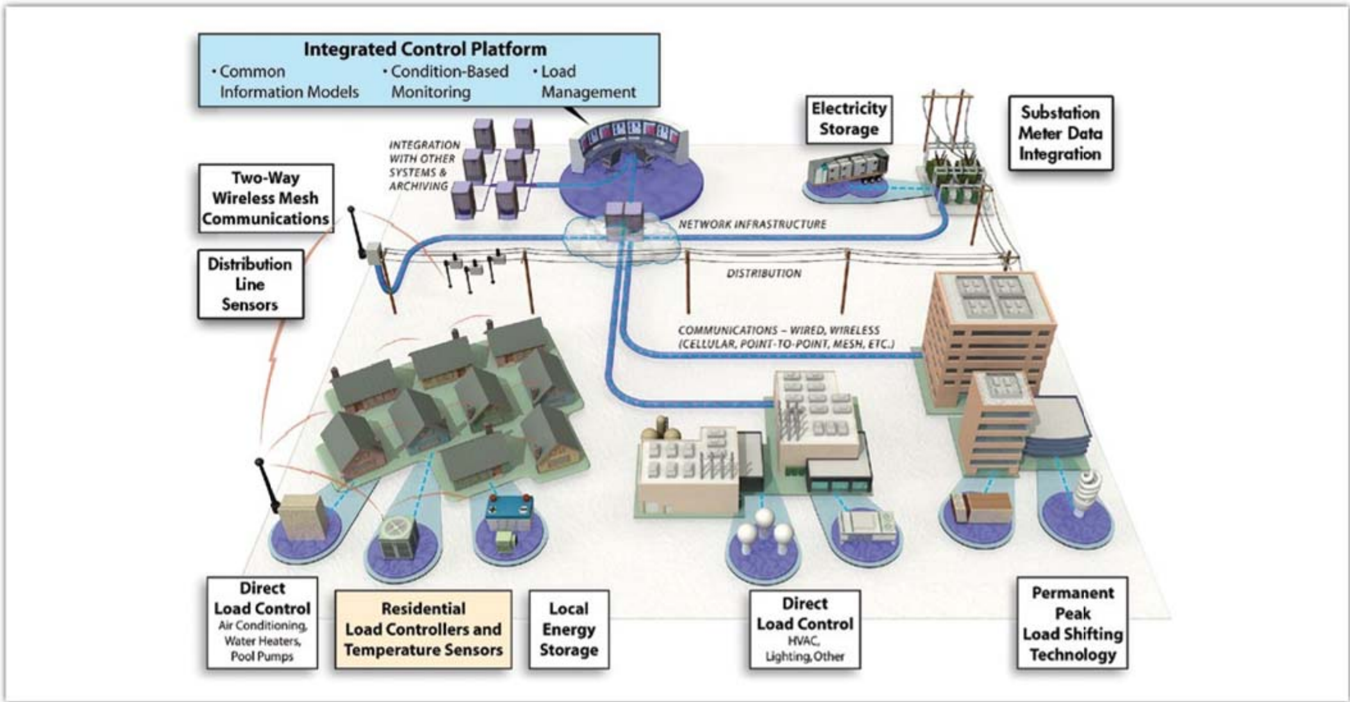
Lessons Learned

- 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.

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.

The FirstEnergy Integrated Distributed Energy Resource Management Project, deployed in the central region of the Jersey Central Power & Light (JCP&L) operating company, is enhancing distribution system operations and reliability and participating in regional emergency capacity markets. The project features an Integrated Control Platform that receives data from monitoring devices via a two-way communication system, enabling visualization of distribution system status.

FirstEnergy Case Study on 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.

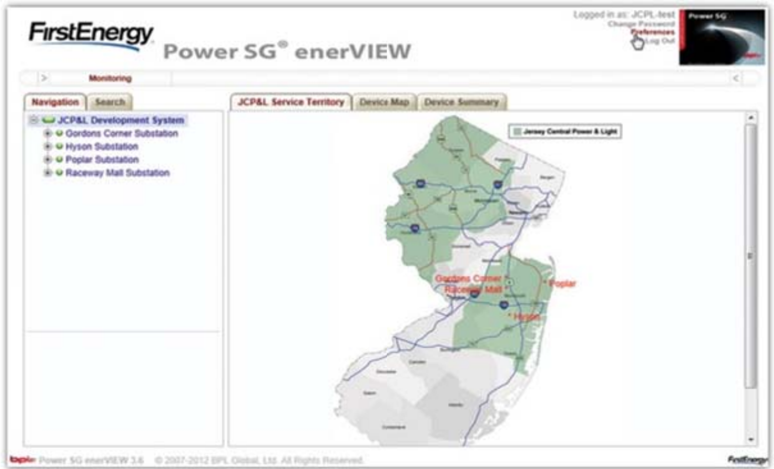


Figure 1: Map with substation hyperlinks

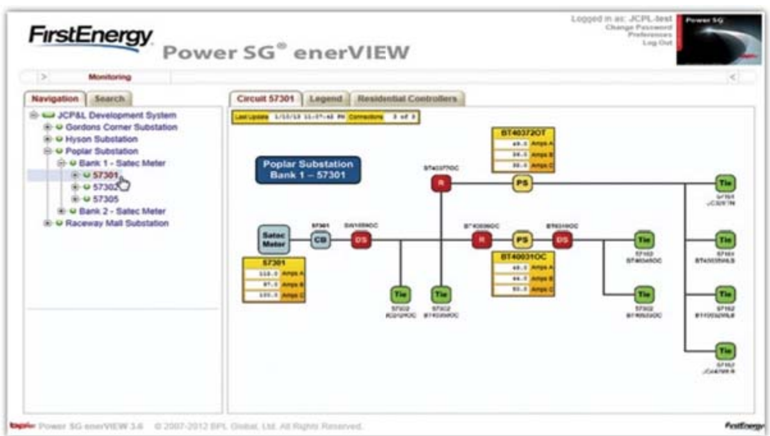


Figure 2: Circuit schematic

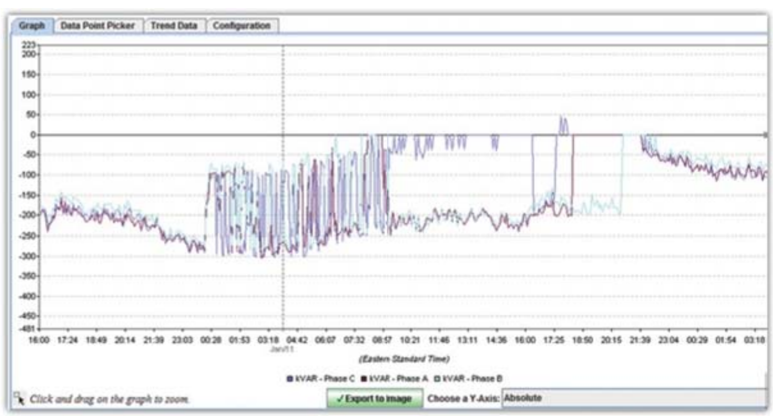
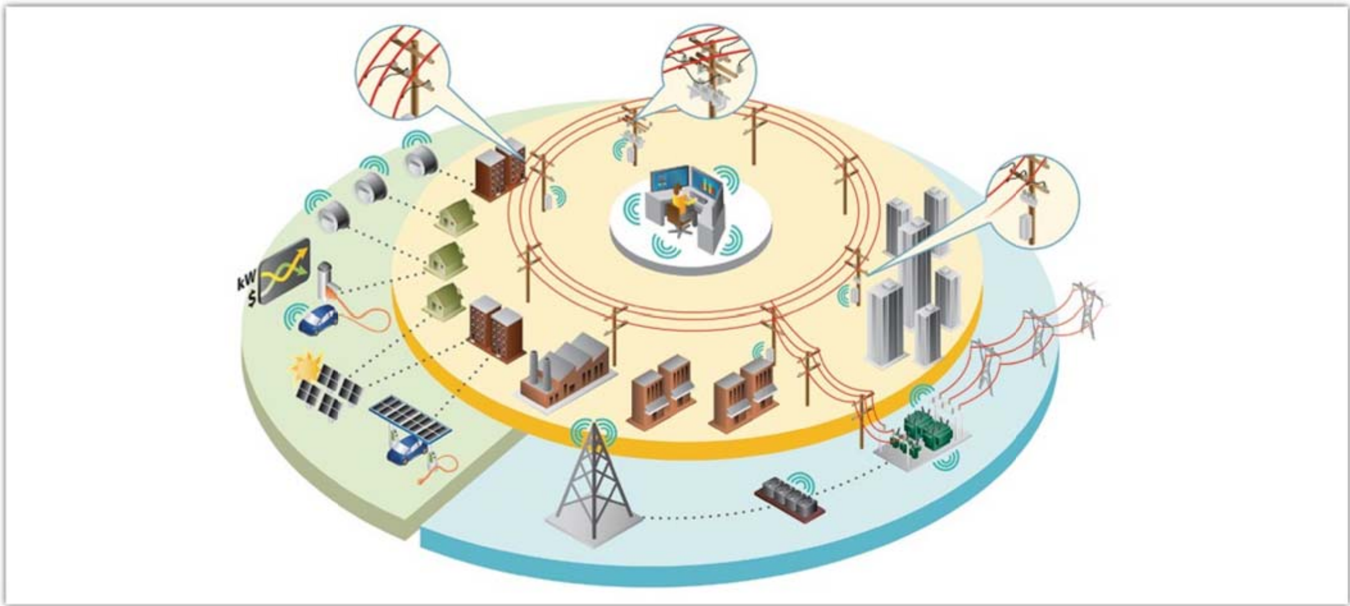


Figure 3: Capacitor bank operation showing erratic operations on all 3 phases

Hydro-Québec | *Case Study One*



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

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.

Hydro-Québec Case Study on Anti-islanding Protection of Distributed Generation using Autoground

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 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.

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.

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

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.

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

- 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.

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.

Left is sectionalizing switch; middle and right show autoground switch

Hydro-Québec | *Case Study Two*

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.

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.

Hydro-Québec Case Study on 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.

Figure 1: Medium voltage monitoring stations

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 2: Automated distribution capacitor banks

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.

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.

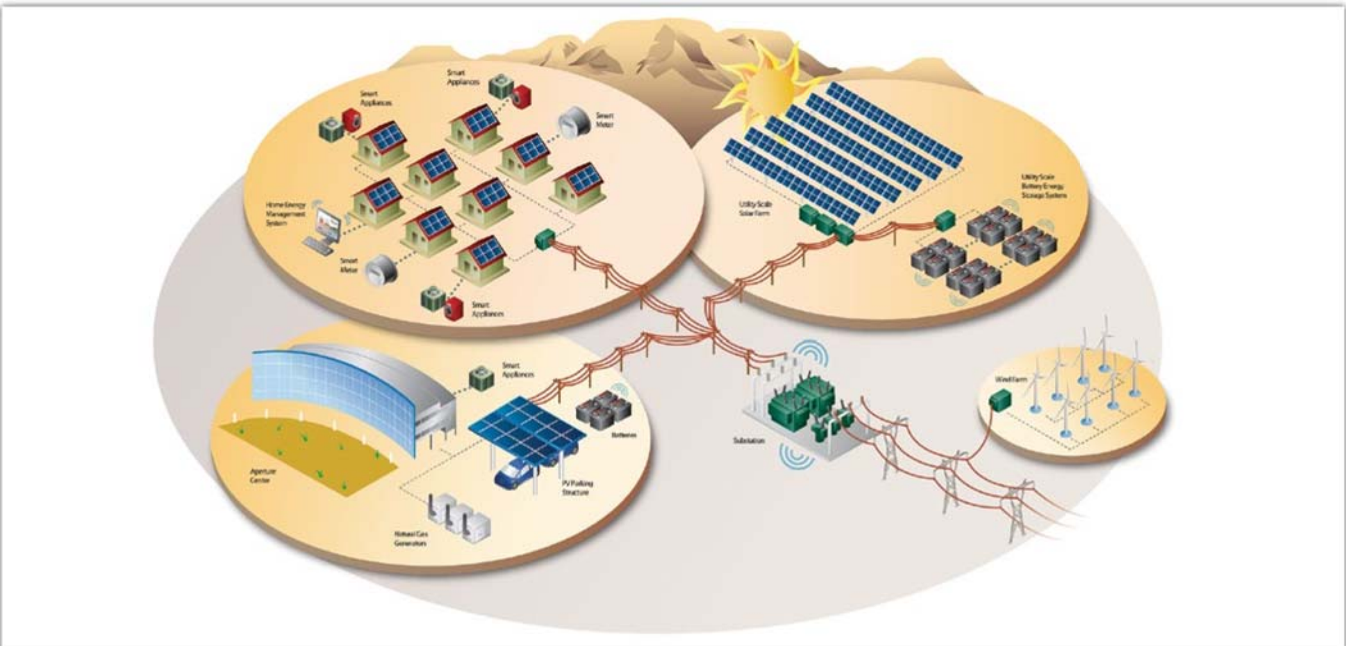
Lessons Learned from the Field

- 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.

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.

PNM Case Study on 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.

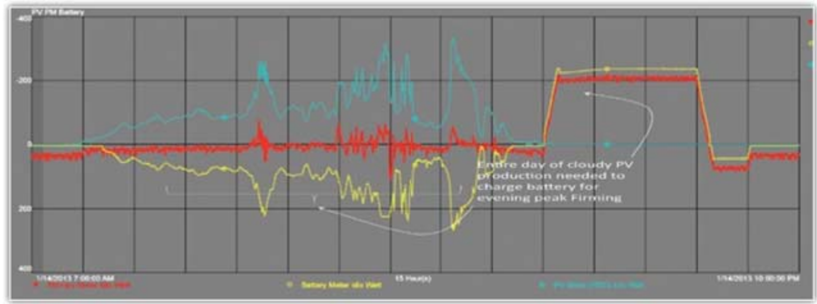
Both smoothing and shifting are critical for a distribution system with a high penetration of photovoltaic generation. Smoothing PV output is important since PV ramp rates (the speed at which power output increases or decreases) can be very fast, going from full power output to zero in just a few seconds. 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.

A rigorous test plan will continue into early 2014. Efforts to further optimize the shifting and smoothing algorithms as well as improve cloud-cover prediction are also underway.

Salt River Project

A wireless broadband network can be integrated with multiple devices and applications across a utility to serve as the unifying infrastructure of a field area network.

Salt River Project (SRP) is a collaborating member of the Smart Grid Demonstration Initiative, and to help create a smart grid is conducting a Field Area Network Pilot. This effort will position SRP to meet the future wireless communications needs for the proliferation of intelligent electronic devices (IEDs) beyond substations.

Salt River Case Study on a Field Area Network (FAN) Pilot

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 & unlicensed point-to-multipoint, paging, 900 MHz unlicensed mesh, and public carrier systems. The applications supported by these communications include Distribution Feeder Automation (DFA), volt-var control, advanced meter infrastructure (AMI) and Water SCADA.

SRP envisions the majority of these systems will be unified using a wireless broadband network. This will create a larger economy of scale and provide room for growth. As such, the FAN Pilot is examining how to provide communication for multiple applications through a common infrastructure. This case study provides results of the first round of tests conducted.

Wireless Network

SRP is testing WiMAX system equipment 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. The following items are being tested:

- GE Mercury MDS 3650 Base Station
- GE Mercury MDS 3650 IDU
- GE Mercury MDS 3650 ODU
- GE PulseNet Enterprise NMS
- Airspan AirSynergy Base Station
- Airspan V70 CPE
- Airspan V72 CPE
- Airspan Netspan NMS

Devices/Applications

The following devices are currently being utilized in the pilot network:

- Two Way Capacitor Controllers
  - HD Electric
  - Beckwith
- Distribution Feeder Automation RTUs
  - GE DART
- Transformer Monitor
  - Serveron
- Video Cameras
  - Axis
- Water SCADA

HD Electric & Beckwith Controllers – GE IDUs

Serveron Transformer Monitor – GE ODU

Applications that could be included in future testing:

- Advanced meter infrastructure backhaul
- Remote fault indication
- Workforce mobility

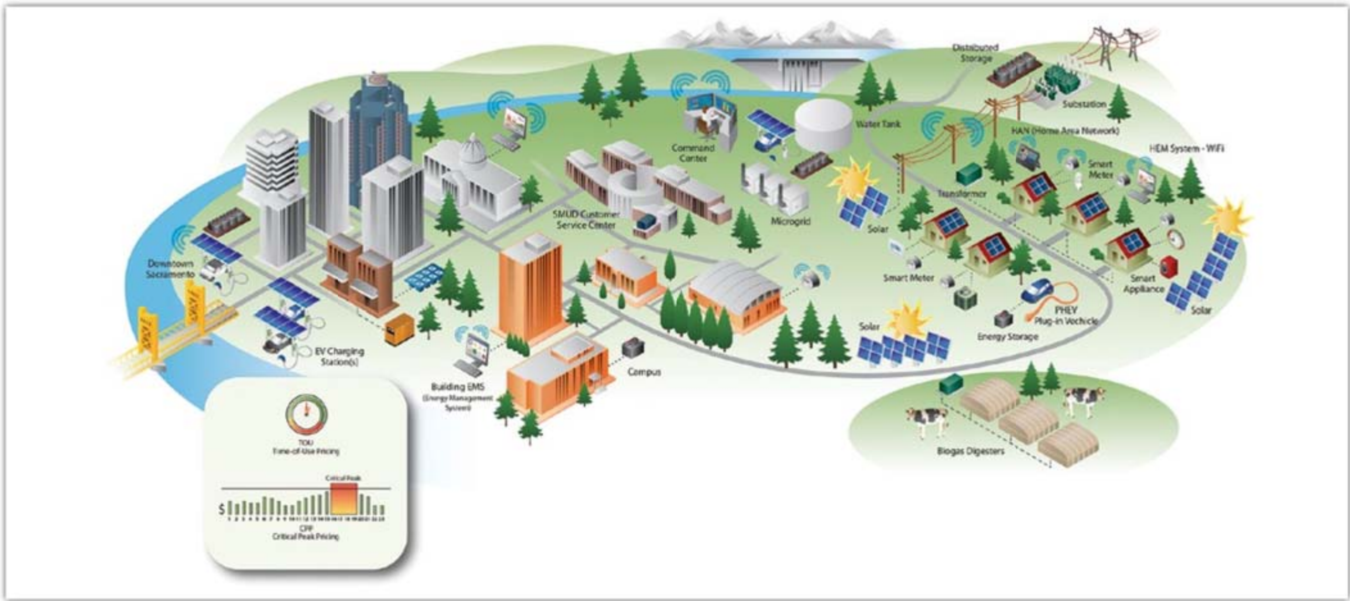
Lessons Learned

The FAN pilot has resulted in many lessons learned, with more anticipated when testing concludes in 2014.

- Two-way capacitor controllers for volt-var control provide a great deal of useful information compared with the existing one-way paging system. This information includes voltage, delta voltage, communication status, temperature, and capacitor bank status.
- New technology has the capability to support legacy serial devices and protocols.
- IP-based technology allows for easier integration into existing networks.
- Usage of the 3.65 GHz spectrum range for a full system deployment could be difficult as many wireless Internet service providers are currently utilizing the band. Continued research is taking place for 3.65 GHz alternatives for a possible system deployment.
- Many new IEDs have optional Ethernet ports allowing for a more simplified integration approach in an IP network.
- An IP-based broadband wireless network does have the capability to unify some of the unique-point solutions in the system today.
- FAN deployment plans depend heavily on prospective user requirements and users' deployment timelines. The deployment plans should be closely aligned.

Overall, initial results lead researchers to believe the unification of wireless infrastructure using a broadband solution is possible and continued work will determine if the costs can be justified. Final testing for the pilot is currently taking place with results expected by 2014. An initial cyber-security test has been performed by EPRI with a second phase of testing scheduled in 2013. EPRI is also leading the analysis of a public versus private communications system, along with a cost benefit analysis. All results from the project, including a technology analysis, public versus private assessment, and cost benefit analysis, will be used to propose a direction and strategy for the future of SRP's wireless field communications.

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.

The Sacramento Municipal Utility District (SMUD) Smart Grid Demonstration Project, Smart Sacramento®, is a collection of 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.

SMUD Case Study on 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.

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.

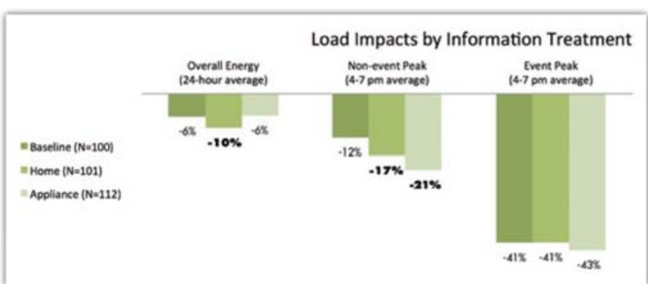


Figure 1: Numbers in bold are significantly different from Baseline

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.

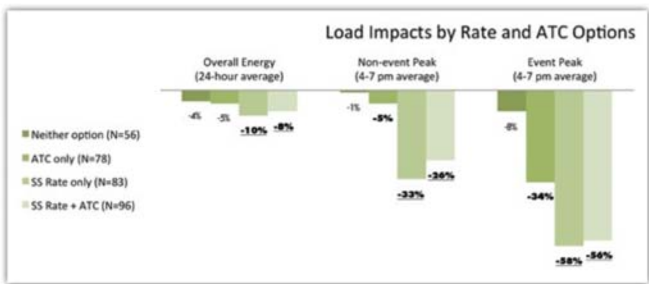


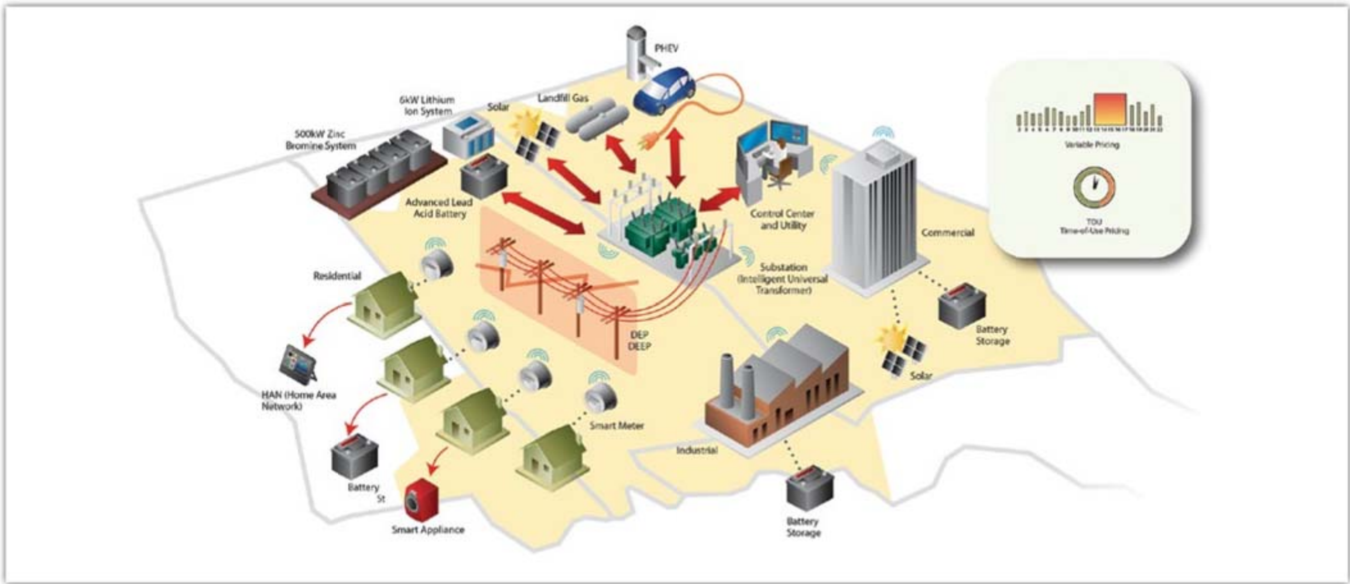
Figure 2: Numbers in bold are significantly different from Baseline. Underlined numbers are significantly different from ATC.
ATC = automated automatic thermostat temperature control;
SS Rate = Summer Solutions Rate

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.

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 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.

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

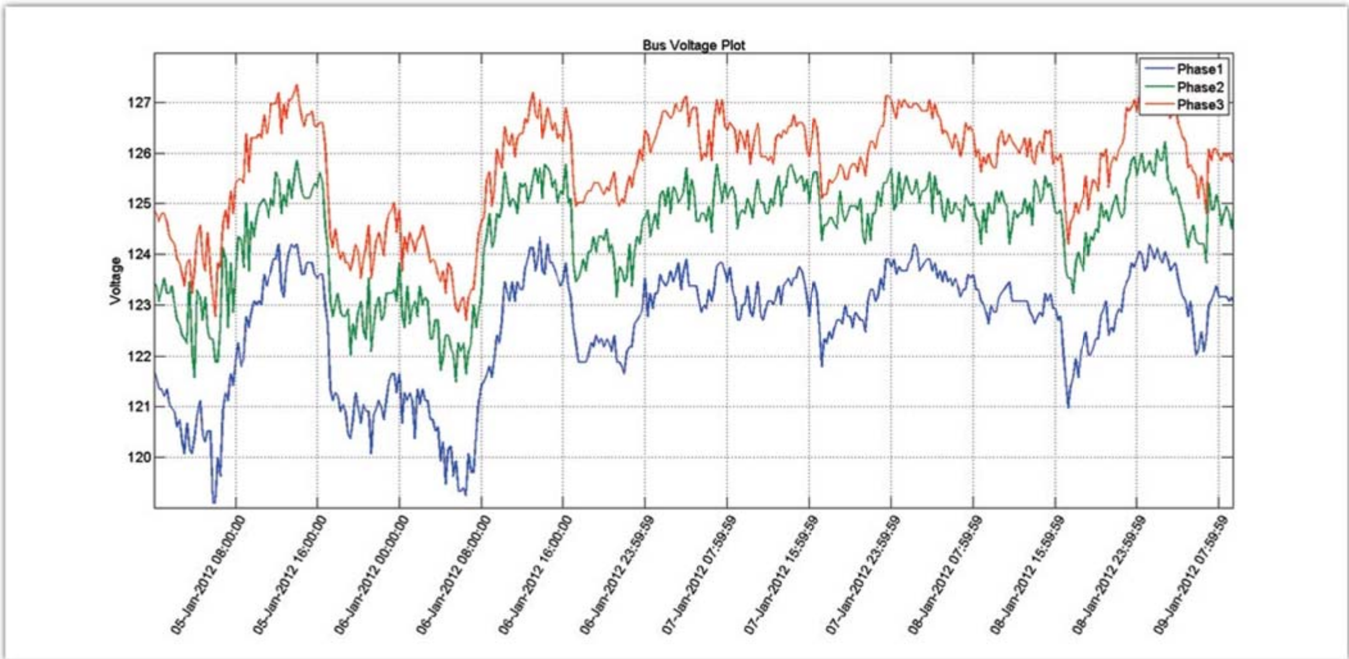
The purpose of this research was to address the adverse effects of distribution capacitors on substation bus voltage with a load-tap-changing (LTC) power transformer. Capacitors provide leading reactive power (measured in kvars) to the electric system to counteract the inductive (lagging) reactive power 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%



Substation Bus Voltage

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.

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.

Deliverables

Smart Grid Demonstration Initiative deliverables present research results for members; however, several documents of interest to the utility industry can be downloaded by the public. These documents are noted as "public" following the Product ID in the list of deliverables below. Public documents can be accessed by searching for the Product ID number on www.epri.com.

All materials available at www.smartgrid.epri.com are also available to the public. This includes the Use Case Repository, a collection of use cases and requirements developed within the industry as well as through EPRI's Smart Grid Demonstration Initiative. In addition, the Smart Grid Demonstration Update newsletter can be obtained at the site.

COMMUNICATIONS

2013
Utility Grade Communications - Smart Grid Training Session #8
Product ID 3002001096

2012
IEC 61850 for the Smart Grid - Smart Grid Training Session #6
Product ID 1025677

2011
Smart Grid Communications – Smart Grid Training Session #2 - October 2011
Product ID 1023428

COST BENEFIT ANALYSIS

2012
Cost Benefit Analysis for the Smart Grid - Smart Grid Training Session #5
Product ID 1025676

Guidebook for Cost/Benefit Analysis of Smart Grid Demonstration Projects
Product ID 1025734 ***(public)***

2011
Estimating the Costs and Benefits of the Smart Grid
Product ID 1022519 ***(public)***

2010
Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects:
Product ID 1020342 ***(public)***

CUSTOMER APPLICATIONS

2012
Case Study on Customer Acceptance and Technology Adoption: Kansas City Power & Light
Product ID 1026444

Synthesizing Utility Experiences in Educating and Engaging Customers in Smart Meter/ Smart Grid Deployments
Product ID 1026432

2011
Consumer Engagement: Facts, Myths, and Motivations
Product ID 1024566 ***(public)***

Commonwealth Edison Company Customer Applications Program – Objectives, Research Design, and Implementation Details
Product ID 1022266 ***(public)***

Commonwealth Edison: The Effect on Electricity Consumption of the Commonwealth Edison Customer Application Program Pilot: Phase 1, Appendices
Product ID 1022761 ***(public)***

The Effect on Electricity Consumption of the Commonwealth Edison Customer Applications Program: Phase 2 Final Analysis
Product ID 1023644 ***(public)***

Grid Strategy 2011: Consumer Engagement
Product ID 1024565

CYBER SECURITY

2012
Grid Strategy 2012: Cyber and Physical Strategy for Substation and Field Equipment
Product ID 1025843

2011
Grid Strategy 2011: Security in Demonstrations
Product ID 1024573

Smart Grid Cyber Security – Smart Grid Training Session #3 - December 2011
Product ID 1023489

DEMAND RESPONSE

2012
A Case Study on Remote Dispatch of Customer-Owned Resources: Consolidated Edison
Product ID 1026437

Case Study on Impact of Advanced Metering Infrastructure (AMI) on Demand Response: Commonwealth Edison
Product ID 1026442

Case Study on Smart-Meter Customer Behavior Trial: ESB Networks
Product ID 1026441

The Effect on Electricity Consumption of the Commonwealth Edison Customer Application Program: Phase 2 Supplemental Information
Product ID 1024865 ***(public)***

The Response Precision of the PREMIO Virtual Power Plant: Électricité de France
Product ID 1026439

2011
Decision Support for Demand Response Triggers: Methodology Development and Proof of Concept Demonstration
Product ID 1022318 ***(public)***

2010
Tennessee Valley Authority/ Bristol Tennessee Essential Services Smart Water Heater Pilot: Summary of Data Analysis and Results
Product ID 1020674

2009
Bristol Tennessee Essential Services (BTES) / Tennessee Valley Authority (TVA) Smart Water Heater Project – Technology Description and Installation Lessons Learned
Project ID 1020213

DISTRIBUTED ENERGY RESOURCES

2013
Smart Inverter - Smart Grid Training Session #9
Product ID 3002001873

Case Study on Integrated Distributed Energy Resources (IDER) Management: FirstEnergy
Product ID 1026443

2012
Case Study on Assessment of Achieving Increased Reliability with Distributed Energy Resources: Consolidated Edison
Product ID 1026438

A Case Study on the Demonstration of Storage for Simultaneous Voltage Smoothing and Peak Shifting
Product ID 1026445 ***(public)***

Case Study on Smart Green Circuits: ESB Networks Part 1 & 2
Product ID 1026440

Distributed Energy Resources Integration in the Smart Grid Demonstration Project
Product ID 1025778

Hawaiian Electric Company (HECO) Smart Grid Demonstration Project: "Distributed hierarchical control systems to facilitate the interconnection of high PV and EV penetration levels"
Product ID 1024840 ***(public)***

System Protection Implications with DER - Smart Grid Training Session #7
Product ID 1025678

2010
Architecture Considerations for Integration of Distributed Energy Resources (DER): EPRI Smart Grid Demonstration Meeting Panel Session Proceedings, March 4th, 2010
Product ID 1021265

Architecture Reference Design for Distributed Energy Resource Integration
Product ID 1020340

Concepts to Enable Advancement of Distributed Energy Resources
Product ID 1020432 ***(public)***

Distributed Energy Resources and Management of Future Distribution
Product ID 1020832 ***(public)***

Regional Profiles for Distributed Resource Integration
Product ID 1020312

2009
Assessment of Wholesale Market Opportunities for Participation and Aggregation of Distributed Resources
Product ID 1020314

Development of a Standard Language for Photovoltaic and Storage Integration
Product ID 1020435

Distributed Resource Integration Framework
Product ID 1020313

EPRI Pre-Conference Workshop: Active Distribution System Management for Integration of Distributed Resources Research, Development and Demonstration Needs: Workshop Proceedings, Nice, France, December 9, 2008.
Product ID 1018926

Methods to Firm Distributed Energy Resources
Product ID 1020385

Smart Grid Distributed Energy Resources (DER) Projects Assessment
Product ID 1018945

Summary of Potential Use Cases for Distributed Solar (PV) Integration
Product ID 1019584

GRID MANAGEMENT
(Distribution Management Systems, CVR, Volt-Var Control)

2013
A Case Study on Anti-islanding Protection of Distributed Generation using Autoground: Hydro-Québec Smart Grid Demonstration
Product ID 3002001375 ***(public)***

A Case Study on Testing and Certification of Equipment for a Volt-Var Control at Hydro Québec: Hydro-Québec Smart Grid Demonstration
Product ID 3002001379

2012
Distribution System Equipment Survey: Hydro-Québec Smart Grid Demonstration
Product ID 1026590

Case Study on Conservation Voltage Reduction and Volt-VAR Optimization: Sacramento Municipal Utility District
Product ID 1026446

ESB Networks Case Study on Distribution Volt-VAR Control Integrated with Wind Turbine Inverter Control:
Product ID 1026589

2012 Grid Strategy: Distribution Management System (DMS) Advanced Applications for DER
Product ID 1025572

Smart Grid Conservation Voltage Reduction/Volt-Var Optimization - Smart Grid Training Session #4
Product ID 1024628

Case Study on Capacitor Bank Health Monitor: Southern Company
Product ID 1026447

Field Data Integration for Asset Management and Grid Operations: EPRI's Coordinated Research
Product ID 1025000 **(public)**

System Protection Implications with DER - Smart Grid Training Session #7
Product ID 1025678

2011

Advanced Distribution Management Systems (DMS) Applications– Smart Grid Training Session #1
Product ID 1023169

Grid Strategy 2011: Conservation Voltage Reduction and Volt VAR Optimization in the Smart Grid
Product ID 1024482

Grid Strategy 2011: Distribution Management System Data Visibility
Product ID 1024661

Grid Strategy 2011: Distribution Management System Data Visualization—An EPRI White Paper
Product ID 1024621

ENERGY STORAGE

2012

A Case Study on Simulation of Community Energy Storage: American Electric Power
Product ID 1026436

A Case Study on the Demonstration of Storage for Simultaneous Voltage Smoothing and Peak Shifting
Product ID 1026445 **(public)**

2011

Grid Strategy 2011: Energy Storage Monetization
Product ID 1024483

Utility Compatibility Evaluations on GreenSmith Energy Storage Utility Interconnected System
Product ID 1022750

EVENTS

2012

Strategic Intelligence Update - Smart Grid Conferences and Events, March 2012
Product ID 1024592

Strategic Intelligence Update: Smart Grid Conferences and Events, August 2012
Product ID 1025760

Strategic Intelligence Update: Smart Grid Conferences and Events, October 2012
Product ID 1025761

Strategic Intelligence Update: Smart Grid Conferences and Events, December 2012
Product ID 1025762

2011

A Utility Application Implementation Strategy Using the EPRI IntelliGrid Methodology and the GridWise Architecture Council Stack as a Model
Product ID 1024590

Heart Transverter HT2000: Test and Evaluation
Product ID 1023251

Standard Portfolio Analysis at Public Service of New Mexico
Product ID 1024459

Strategic Intelligence Update: Smart Grid Conferences and Events, June 2011
Product ID 1021472

Strategic Intelligence Update: Smart Grid Conferences and Events, September 2011
Product ID 1023427

2010

Smart Grid Leadership Report: Global Smart Grid Implementation Assessment
Product ID 1021417 **(public)**

Smart Grid Technologies Report
Product ID 1020415

Strategic Intelligence Update: Smart Grid Conferences and Events, January 2010
Product ID 1020566

Strategic Intelligence Update: Smart Grid Conferences and Events, July 2010
Product ID 1021444

Strategic Intelligence Update – Smart Grid Conferences and Events, November 2010
Product ID 1021471

Utility Reference Guide to the National Institute of Standards and Technology Smart Grid Standards Effort
Product ID 1020343

2009

Integration of Requirements and Use Cases into an Industry Model
Product ID 1020384

Strategic Intelligence Update – Smart Grid Conferences and Events
Product ID 1020214

HOST SITE PROJECT DESCRIPTION AND OVERVIEW

2012

Hawaiian Electric Company (HECO) Smart Grid (SG) Demonstration Project Description
Product ID 1025764

2011

Hydro-Québec Smart Grid Demonstration Host-Site Overview
Product ID 1023414 **(public)**

Hydro-Québec Smart Grid Demonstration Host-Site Project Description
Product ID 1023405

Sacramento Municipal Utility District (SMUD) Smart Grid Demonstration Host-Site Overview
Product ID 1023413 **(public)**

Sacramento Municipal Utility District (SMUD) Smart Grid Demonstration Host-Site Project Description
Product ID 1023406

Southern California Edison's Smart Grid Demonstration Project: Irvine Smart Grid Demonstration (ISGD)
Product ID 1021420 **(public)**

2010

Duke Energy Smart Grid Demonstration Host-Site Project Description
Product ID 1021399

Duke Energy Smart Grid Demonstration Overview
Product ID 1021421 **(public)**

ESB Networks Smart Grid Demonstration Host-Site Overview
Product ID 1020598 **(public)**

ESB Networks Smart Grid Demonstration Host-Site Project Description
Product ID 1020597

Exelon Smart Grid Demonstration Host-Site Project Description
Product ID 1020893

Exelon Smart Grid Demonstration Project
Product ID 1021419

KCP&L Smart Grid Demonstration Overview
Product ID 1021418 **(public)**

KCP&L Smart Grid Demonstration Host-Site Project Description
Product ID 1020892

Southern California Edison (SCE) Smart Grid Demonstration Host-Site Project Description
Product ID 1021398

Southern Company Smart Grid Demonstration Host-Site Project Description
Product ID 1021400

Southern Company Smart Grid Demonstration Project
Product ID 1021422 **(public)**

2009

AEP Smart Grid Demonstration Host-Site Overview
Product ID 1020226 **(public)**

American Electric Power (AEP) Smart Grid Demonstration Host-Site Project Description
Product ID 1020188

Con Edison Smart Grid Demonstration Host-Site Overview
Product ID 1020227 **(public)**

Con Edison Smart Grid Demonstration Host-Site Project Description
Product ID 1020190

Électricité de France (EDF) Smart Grid Demonstration Host-Site Overview
Product ID 1020228 **(public)**

Électricité de France (EDF) Smart Grid Demonstration Host-Site Project Description
Product ID 1020191

FirstEnergy Smart Grid Demonstration Host-Site Overview
Product ID 1020229 **(public)**

FirstEnergy Smart Grid Demonstration Host-Site Project
Product ID 1020189

PNM Smart Grid Demonstration Host-Site Overview
Product ID 1020230 **(public)**

PNM Smart Grid Demonstration Host-Site Project Description
Product ID 1020187

PROGRAM DOCUMENTS AND COMPILATIONS

2013

International Smart Grid Demonstration Project Case Studies and Survey Analysis
Product ID 1026756

2012

A Smart Grid Reference Guide to Integration of Distributed Energy Resources: 2012 Version
Product ID 1025763

EPRI Smart Grid Demonstration Initiative Four Year Update
Product ID 1025781 **(public)**

Smart Grid Demonstration Initiative Case Studies
Product ID 1026435

2011

A Smart Grid Reference Guide to Integration of Distributed Energy Resources, First Edition
Product ID 1023412

EPRI Smart Grid Demonstration Initiative Three Year Update
Product ID 1023411 **(public)**

2010

Smart Grid Demonstration Two-Year Update
Product ID 1021497 **(public)**

2009

Smart Grid Demonstration Overview
Product ID 1020225

PROGRESS REPORTS

2012

Duke Energy Smart Grid Host Site Progress Report for the Period Ending November 2012
Product ID 1025571

Hydro-Québec Smart Grid Host Site Progress Report
Product ID 1024839

Kansas City Power & Light Company Smart Grid Host Site 2011 Progress Report
Product ID 1024501

Southern California Edison Smart Grid Host Site Progress Report
Product ID 1025688

Southern Company Smart Grid Host Site Progress Report
Product ID 1025570

2011

American Electric Power Smart Grid Host Site Progress Report: Period Ending December 2010
Product ID 1021501

Electricity Supply Board Smart Grid Host Site Progress Report for the Period Ending February 2011
Product ID 1023253

Électricité de France Smart Grid Host Site Evaluation Report After Six Months of Operation
Product ID 1024460

Électricité de France Smart Grid Host Site Progress Report
Product ID 1022675

Sacramento Municipal Utility District Smart Grid Host Site Progress Report: Period Ending November 2011
Product ID 1024620

Southern California Edison Smart Grid Host Site Progress Report
Product ID 1024574

2010

American Electric Power (AEP) Smart Grid Host Site Progress Report
Product ID 1020354

Consolidated Edison Smart Grid Host Site Progress Report
Product ID 1021500

Consolidated Edison Smart Grid Host Site Progress Report:
Product ID 1020355

Électricité de France Smart Grid Host Site Progress Report
Product ID 1021488

ESB Networks Smart Grid Host Site Progress Report
Product ID 1021489

FirstEnergy Smart Grid Host Site Progress Report
Product ID 1020352

International Smart Grid Projects Update
Product ID 1020303

PNM Smart Grid Host Site Progress Report
Product ID 1020353

Public Service Company of New Mexico Smart Grid Host Site Progress Report
Product ID 1021490

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 over 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.

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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.

GERALD R. GRAY, PHD

Gerald R. Gray is a Senior Project Manager 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.

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Christine Haddad is a Project Engineer/Scientist in the Smart Grid Demonstration Initiative in the Power Delivery and Utilization Sector at EPRI. Her current research activities focus on the cost benefit analysis of projects that are part of the Initiative. Ms. Haddad 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.

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.

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