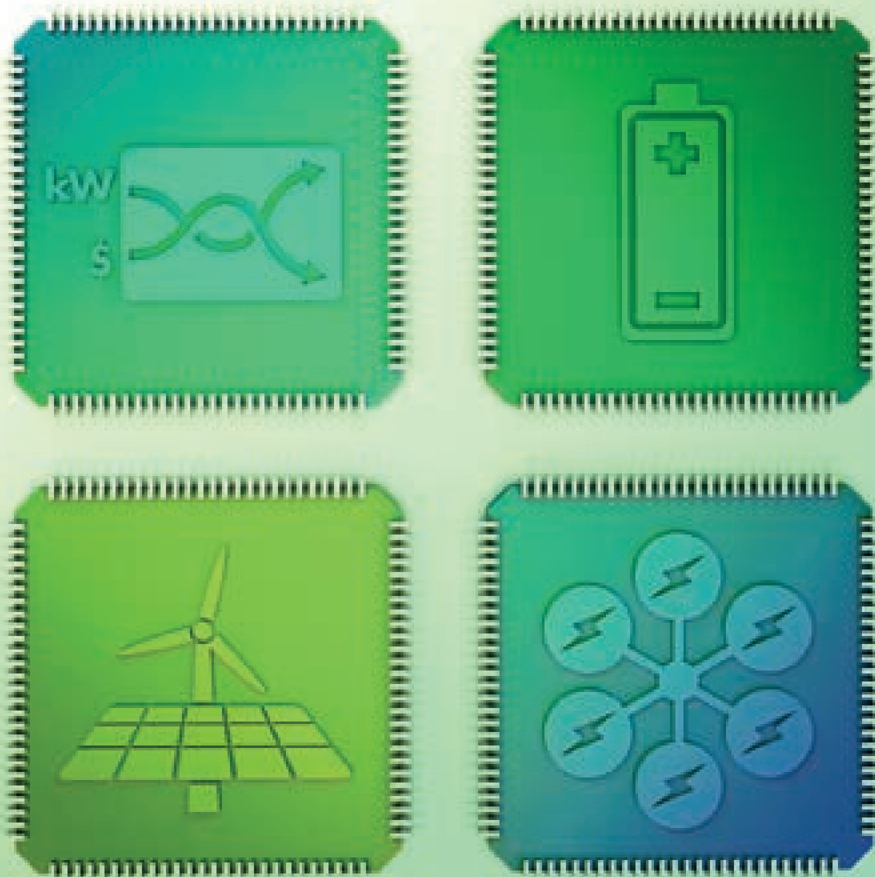
EPRI | ELECTRIC POWER RESEARCH INSTITUTE

EPRI SMART GRID DEMONSTRATION INITIATIVE | 4 YEAR UPDATE



CASE STUDY BRIEF

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EPRI Smart Grid Demonstration Initiative Four Year Update

The EPRI Smart Grid Demonstration Initiative is a seven year international collaborative research initiative demonstrating the integration of Distributed Energy Resources (DER) in large scale demonstration projects. The initiative, which began in 2008, is leveraging multi-million dollar Smart Grid investments in the electric utility industry for a common goal of shared learning that covers a wide breadth of technology, deployment, and program results among 23 participating utilities.

This four-year update picks up where the three-year update (EPRI Report 1023411) left off. Last year, we primarily reported on examples of the people, equipment and work being performed by the members of this initiative. This year as the initiative moved past the half-way mark, the research has progressed into a stage where solid results are becoming available and can be shared among the collaborative. Although we had two utilities join the initiative in 2011, Ergon Energy from Australia and Hawaiian Electric Company, others have been actively deploying equipment to the point where data collection and analysis have enabled completion of case studies focused on specific portions of the demonstrations. We are grateful for the exceptional efforts of many individuals who conducted the studies and documented the results presented here.

A standard case study format was created to enable a similar document outline while still allowing for some variation in the documents tailored to the project being summarized. Each of the case studies completed to date provide an overview and background information followed by the approach/methodology and continue through the results, lessons learned, and conclude with key recommendations. Some case studies may also list some unresolved questions that were uncovered in the demonstration, thus providing a guideline for continued study.

The case study overviews, you will see in the following pages, depict a full range of activities from 10 of the collaborative members. This update contains a condensed summary of each case study. The complete case studies are available and the full content will be included in the 2012 reference guide update.

At the October 2011 Smart Grid Demonstration Advisory Meeting Hosted by Kansas City Power and Light, the members selected the highest three priority research topics for 2012. The strategic topics selected were Distribution Management System (DMS) Applications, DMS Integration, and Cyber Security for Field Equipment. The research goals and deliverables for each topic were established by the members and are being reported on at the three face-to-face advisory meetings hosted at different utilities throughout 2012. The final reports will be presented at the October 2012 advisory meeting that will be hosted by Sacramento Municipal Utility District.

A Smart Grid Reference Guide to Integrating Distributed Energy Resources

The research from this initiative continues to result in an abundance of information. In 2011, EPRI created the First Edition of A Smart Grid Reference Guide to Integrating Distributed Energy Resources. (EPRI Report 1023412). The updated 2012 version (EPRI report 1025763) will be published in September of 2012. This second edition is updated with the case studies and other information and the content is further organized with an updated index and cross references. We will continue to add content to this reference guide with updates in 2013 and 2014. An additional version in electronic format is being considered for access on line or via tablets and "e-reader" devices.

On behalf of the electric utility members of this initiative and the EPRI technical staff, we hope you find this update valuable.

Sincerely,

Matt Wakefield,
Sr. Program Manager, Smart Grid

Gale Horst,
Sr. Project Manager, Smart Grid

Issue Based Research – Extending Collaboration across the Demonstrations

All utilities in the Smart Grid Demonstration Initiative are Collaborators and fund the research performed across the Host Site demonstration projects. All utility Collaborators have the opportunity to propose a Host Site project with research objectives that are aligned with the overall goals of EPRI's initiative. Research performed by EPRI is primarily conducted for Host Site projects; Non-Host Sites also have the opportunity to have targeted research performed that meets at least one of the research goals in the form of "mini-demos." Research results are shared with all the Collaborators.

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**	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■
	Electric Vehicles	■		■		■	■			■	■	■		■	■	■
	Thermal Energy Storage	■			■	■	■	■	■		■	■	■			
	Electric Storage <= 100 kWh	■	■	■	■	■		■	■	■	■		■	■	■	■
	Electric Storage >100 kWh	■				■			■	■		■	■	■	■	■
	Solar Photovoltaic	■		■	■	■		■		■	■	■	■	■	■	■
	Wind Generation						■	■		■						
	Conservation Voltage Reduction	■		■		■	■				■	■		■	■	■
	Distributed Generation	■	■		■	■		■			■	■	■	■		
Communications and Standards	**Customer Domain** (SEP, WiFi...)	■	■	■			■	■			■	■	■	■	■	■
	Distribution (DNP3, IEC 61850...)	■	■	■		■	■	■	■	■	■	■	■	■	■	■
	Enterprise (CIM, MultiSpeak, OpenADR...)	■			■	■	■	■		■	■	■	■	■		■
	Cyber Security		■	■	■	■	■	■		■	■		■	■	■	■
	AMI or AMR	■		■		■	■	■		■	■	■	■	■		■
	RF Mesh or Tower	■				■	■	■	■	■	■	■		■	■	■
	Public or Private Internet		■	■	■	■	■	■			■	■	■	■	■	■
	Cellular 3G (GPRS, CDMA...)	■		■		■	■			■		■	■	■	■	■
	Cellular 4G (WiMAX, LTE...)			■		■					■				■	
Programs	**Price Based** (TOU, CPP, RTP...)	■		■		■	■	■	■			■	■	■	■	■
	Incentive Based (DLC, Interruptible...)	■	■		■	■	■	■	■	■	■	■	■	■	■	■
Ops & Planning	**System Operations Integration**	■	■	■		■	■	■	■	■	■	■	■	■	■	■
	System Planning Integration	■	■	■	■	■	■		■	■	■		■	■	■	■
	Modeling and/or Simulation Tools	■	■	■	■		■		■	■	■		■		■	■
State of Deployment	**Planning**					●				●					●	
	Deploying	●	●	●							●	●		●		●
	Data Collection								●				●			
	Analysis				●		●	●								

■ Technologies and Applications Integrated in the Demonstration ● Demonstration "State of Deployment" in mid-2012

Non-Host-Site members benefit from the knowledge gained without the cost of deploying capital intensive projects, while Host-Sites benefit from research performed specifically on their projects. All of the collaborators have committed to sharing high-level results with the public to help advance smart grid efforts in the industry.

The below matrix identifies high-level technologies and applications of each project that are aligned with the initiative's goals. No single project can evaluate every research scenario, but by collaborating across multiple projects, the research lessons can be greatly enhanced beyond what the projects could do individually.

Primary Integrated Technologies & Applications		Collaborators							
		Ameren	CenterPoint Energy	Central Hudson Gas and Electric	Entergy	Southwest Power Pool	Salt River Project	Tennessee Valley Authority	Wisconsin Public Service
Distributed Energy Resources	**Demand Response Technologies**								
	Electric Vehicles								
	Thermal Energy Storage								
	Electric Storage <= 100 kWh								
	Electric Storage >100 kWh								
	Solar Photovoltaic								
	Wind Generation								
	Conservation Voltage Reduction								
	Distributed Generation								
Communications and Standards	**Customer Domain** (SEP, WiFi...)								
	Distribution (DNP3, IEC 61850...)								
	Enterprise (CIM, MultiSpeak, OpenADR...)								
	Cyber Security								
	AMI or AMR								
	RF Mesh or Tower								
	Public or Private Internet								
	Cellular 3G (GPRS, CDMA...)								
	Cellular 4G (WiMAX, LTE...)								
Programs	**Price Based** (TOU, CPP, RTP...)								
	Incentive Based (DLC, Interruptible...)								
Ops & Planning	**System Operations Integration**								
	System Planning Integration								
	Modeling and/or Simulation Tools								

Cross Collaboration Opportunities

- Areas of Interest
- Similar Project Learnings

Cross-collaborative teams share early technology transfer information on targeted topics across member projects. Results and lessons support existing and emerging projects to advance integration of distributed energy resources.

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.

AEP 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:

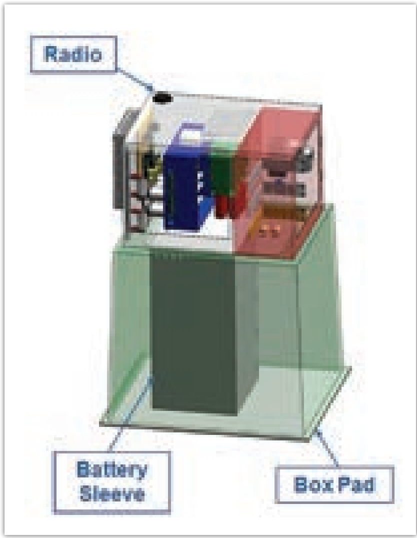
- Peak shaving – The control attempts to discharge the storage to keep the power consumption below a maximum kilowatt value.
- Load following – At a specified time each day, if monitored demand exceeds a pre-determined minimum threshold for discharge, the storage units are dispatched.
- Schedule based – 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

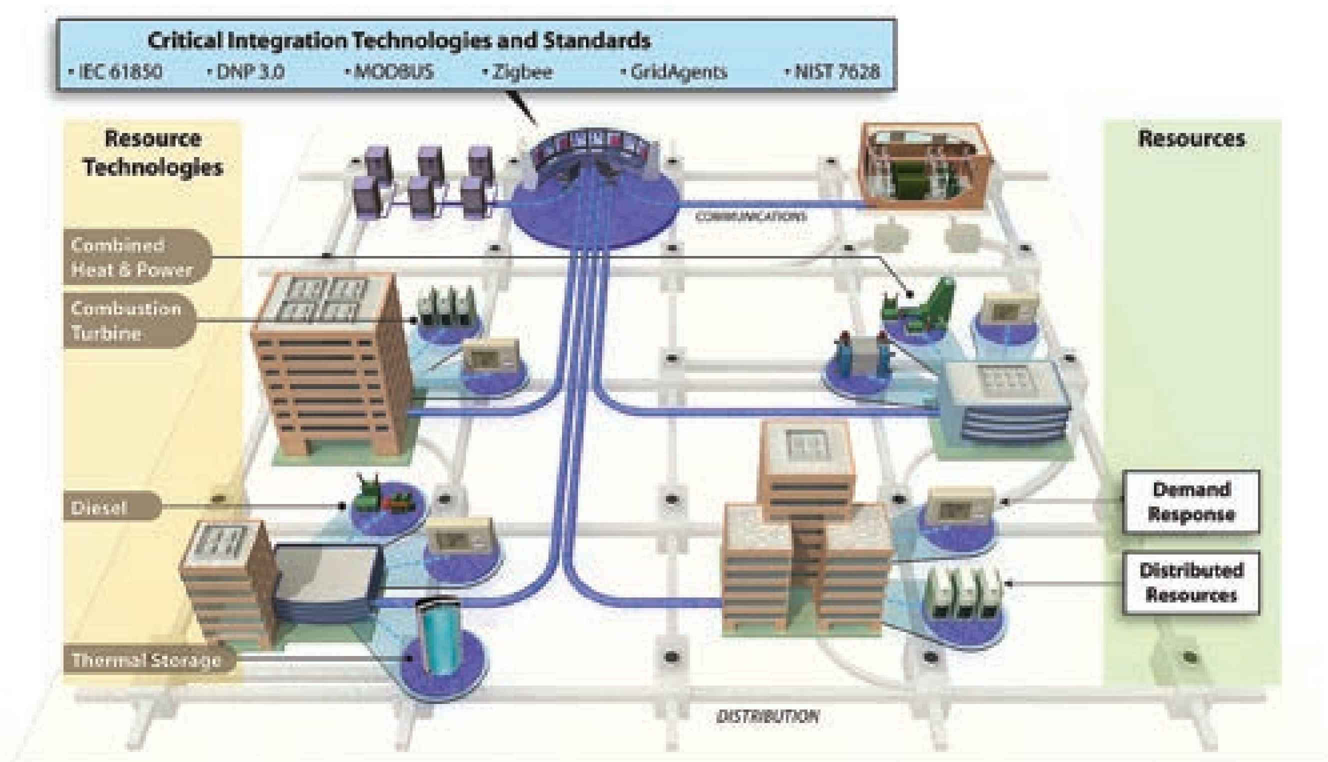
Observations from the simulations include:

- 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.

Consolidated Edison

CASE STUDY 1



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:

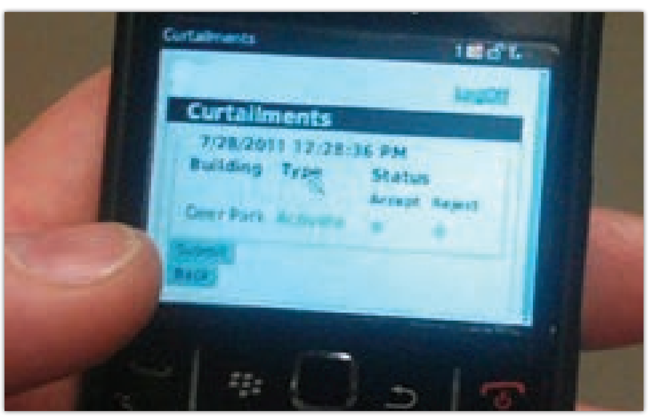
- Receive curtailment "trigger" signals for both reliability and market programs.
- Activate demand response resources in response to triggers.
- Provide a communication gateway between demand response resources and distribution operators.
- Notify stakeholders of changes in status.
- Aggregate a diverse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

Con Edison Case Study on 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.

Consolidated Edison

CASE STUDY 2

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.

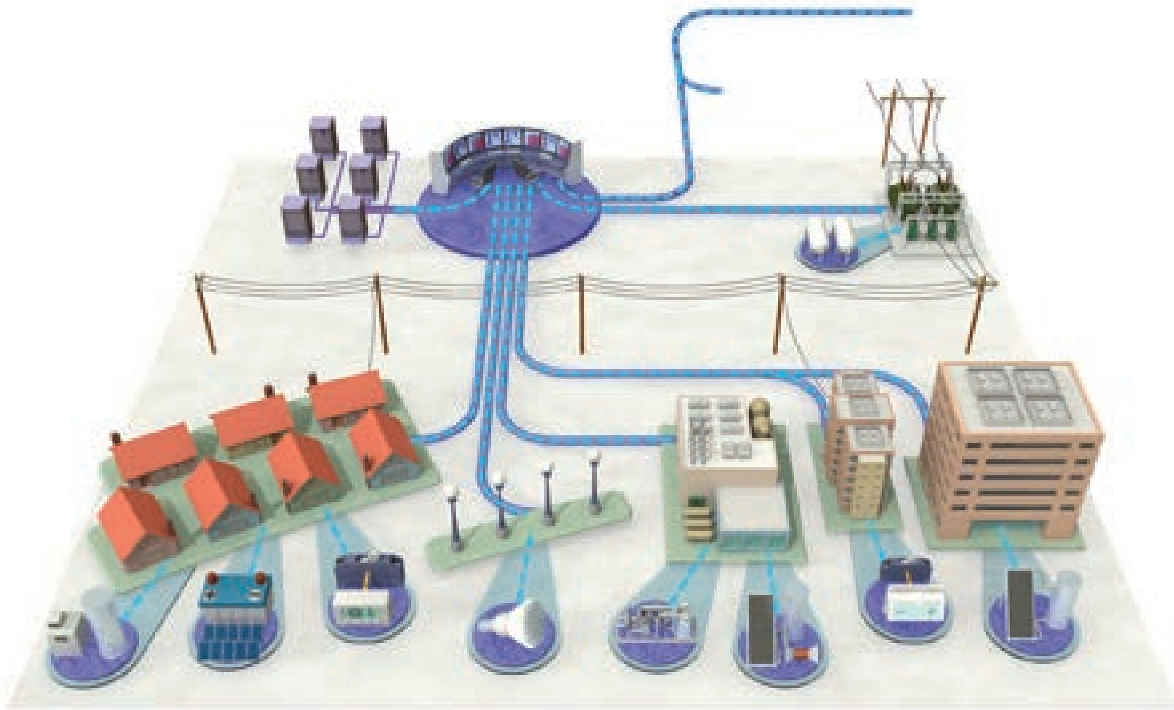
Scenario 3: All of the items in Scenario 2 plus the addition of smart-grid enabled demand response load reductions, deployment of advanced meters, home area networks, smart appliances, and other technologies.

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.

Electricité de France



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

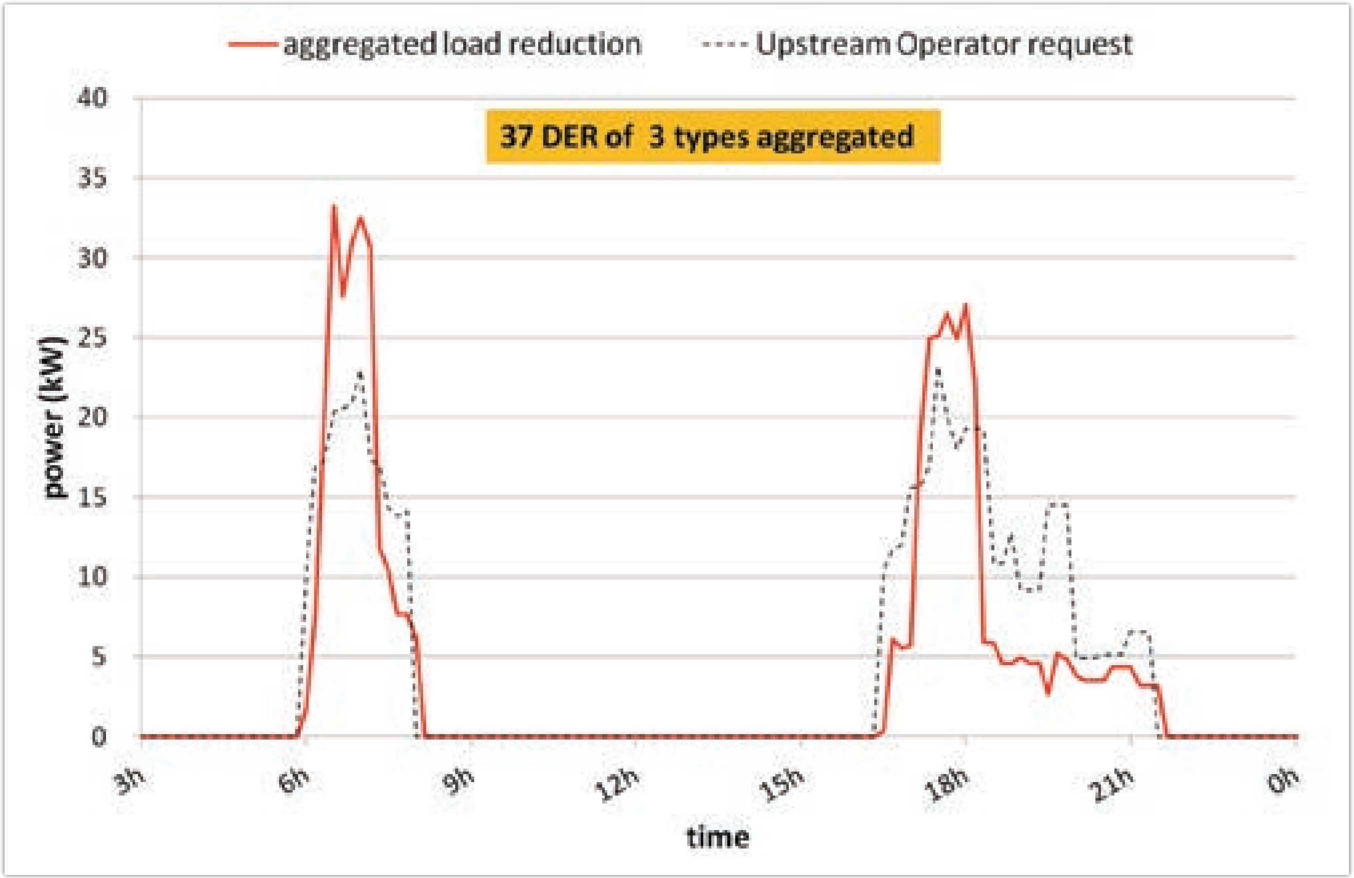
The Electricité de France (EDF) Smart Grid Demonstration features PREMIO (Production Répartie, Enr et MDE, Intégrées et Optimisées), an open architecture system designed to optimize the simultaneous control of distributed energy resources (DER), such as thermal storage and electric batteries, that can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

EDF Case Study on 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.

ESB Networks

CASE STUDY 1

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.

ESB Networks Case Study on Smart Green Circuits

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. Sixty such schemes that entail installation of 300 devices are planned in 2012.
- 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.

ESB Networks
CASE STUDY 2

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.

ESB Networks Case Study on 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.

ESB Networks

CASE STUDY 3

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%

ESB Networks Case Study on a 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.

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.

Commonwealth Edison Case Study on Impact of Advanced Metering Infrastructure (AMI) on Demand Response

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.

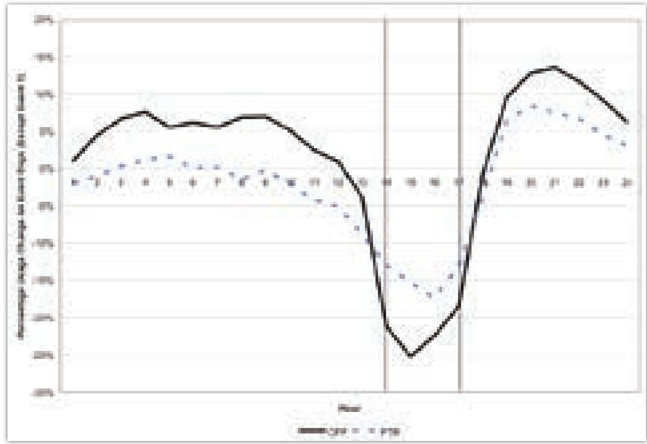
The CAP is notable for its novel design, scale, and extensive scope. Participants were engaged in the first large-scale opt-out method of enrollment. Approximately 8,000 residences out of a population of 130,000 AMI-metered customers in the greater Chicago area were assigned to treatments that involved 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).

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.



Event-Day Load Estimates from CPP and PTR Event Responders

Lessons Learned

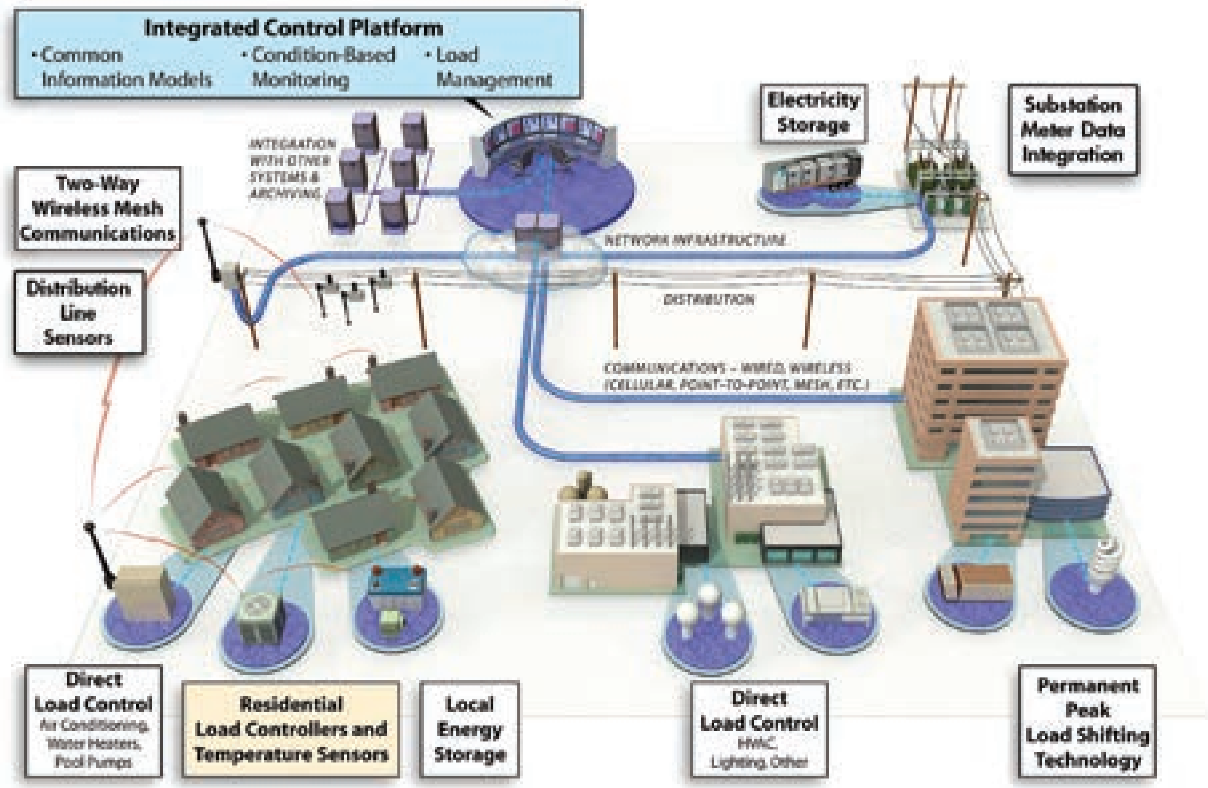
- Statistically significant responses were exhibited by some of the customers served under each rate type. Responders constitute about 10 percent of all customers enrolled in a dynamic rate.
- An opt-out recruitment strategy without a purposeful and persistent customer support effort does not appear 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.

Preview of PECO Case Study on Smart Campus Microgrid

The goal of the PECO project is to create a "Smart Campus" microgrid demonstrating interoperability. The system has been designed to create an intelligent network to balance building operational needs with grid operations and costs and to serve as a model that can be replicated in other markets.

The system had to account for different thermal mass and rate of change in each of the six controlled buildings and accommodate the HVAC time delays (when compared with an electrical response) while maintaining acceptable building comfort levels. Tasks completed include planning models, topological models, dynamic load models and building simulations. The control system was developed and integrated with Drexel's building automation systems. Input data is utilized from the PJM real-time energy market. Load reductions and cost savings are being tabulated for inclusion in a pending case study.

FirstEnergy



Eighteen load-reduction events showed that aggregated resources can support distribution operations and achieve revenue goals for participating in the PJM power market.

The FirstEnergy Integrated Distributed Energy Resource 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.

FirstEnergy Case Study on Integrated Distributed Energy Resources (IDER) Management

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.

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.

PowerSense Installation

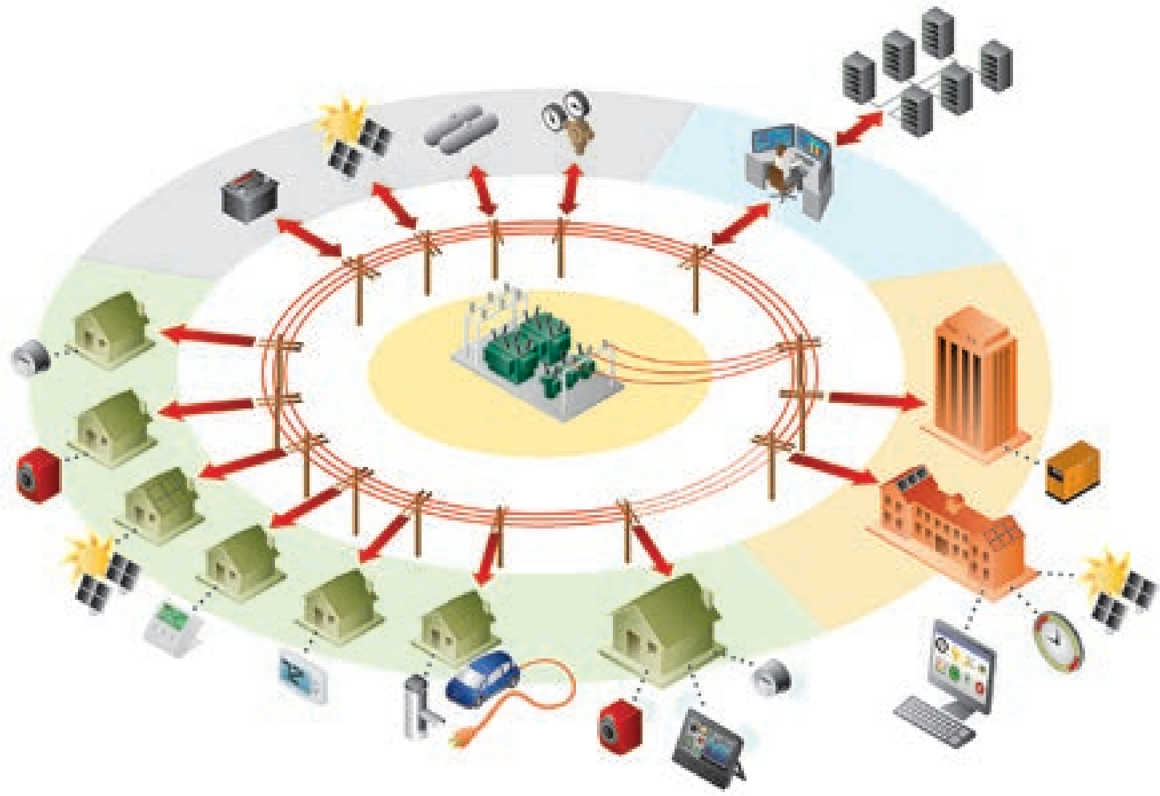
Substation Meter Data Integration

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.

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.

KCP&L Case Study on 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:

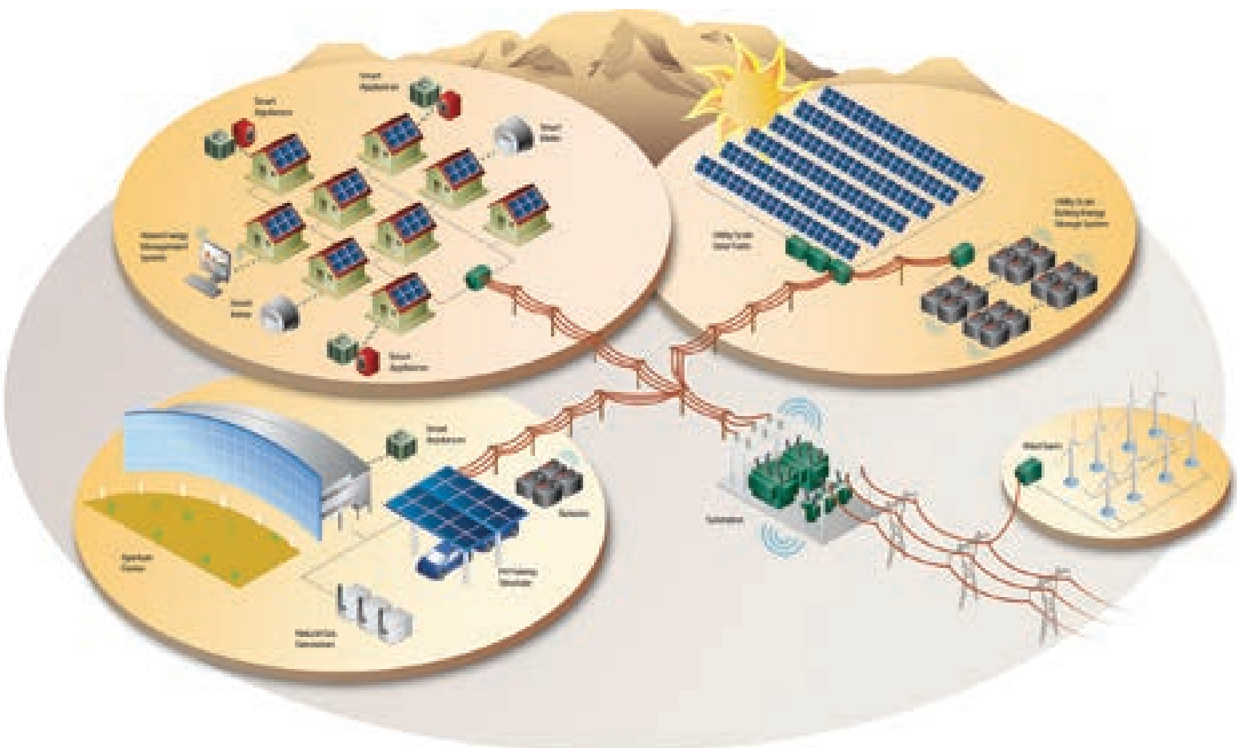
- Updates to the Landys & Gyr advanced meters, which were selected in the very early stages of the demonstration, were required to enable rate data and other cost information to be downloaded to the meters.
- Because of high concentration of displays in one area, network performance was reduced, and 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.

Public Service of New Mexico



A 1-second data capture rate of PV output proved essential to use storage for smoothing functions.

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 500kW 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

As part of its smart grid demonstration, PNM launched its Prosperity Energy Storage Project to create a firm, dispatchable renewables-based peaking resource. PNM designed a system that uses energy stored in batteries to simultaneously mitigate voltage fluctuations through battery smoothing and meet peak demand through battery shifting. This case study presents results of the initial tests of these functions.

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 was the focus of PNM's first shifting tests. Firming is the ability to guarantee constant power output to the electricity market during a certain period of time. This is challenging since there is a misalignment of PV-generated power and system peak demand, with solar peak output typically occurring two hours before the summer system peak in PNM's territory.

Major System Components

The 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 500kW for smoothing. The UltraBattery is built for quick response, operating at a high discharge and charge rate.

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

Baseline data was developed along with detailed computer models of the local grid to guide integration of batteries and PV and to aid in optimizing control strategy and operation. Models were created by the University of New Mexico using the software OpenDSS from EPRI and GridLAB-D™ from Pacific Northwest National Laboratory.

A robust, cyber-secure data acquisition and control system that collects 220 points every second was established, and algorithms developed to automate smoothing and shifting control.

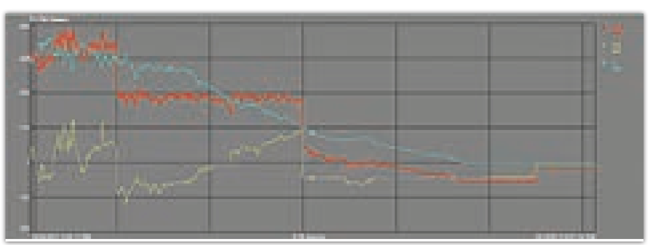
The Tests

Smoothing and shifting tests were conducted separately and simultaneously. For the smoothing test, the algorithm was evaluated at three different smoothing factors: 100%, 70%, and 40%. The speed at which control source signals were received by the battery controller was measured, as well as the effectiveness of using control inputs from the PV meter versus the irradiance meters.

In the energy shifting application, the battery must operate under a lower-rate of discharge and stay within a set state-of-charge window. In the first peak shifting test, a manual command was applied to dispatch stored energy. Later tests automated the shifting command to create a dispatched block of firm energy within state-of-charge limits of the Advanced Lead Acid Battery, and within a specific time window. Future tests will incorporate other input variables such as predictions of feeder load, weather forecasts, and solar output.

Results and Lessons Learned

- No off-the-shelf data acquisition and control system was available. PNM had to develop its own system, using interface requirements developed according to EPRI IntelliGrid methodology.
- Tests confirmed communication of control source signals and the speed at which they were received by the battery controller. Achieving a 1-second data capture rate proved essential. This speed is crucial for smoothing because ramp rates change swiftly and dramatically; the PNM team recorded ramp rates of 136kW/s ramp (+/-) on the 500 kW PV system output.
- Smoothing was achieved during tests, showing good results at all smoothing factors (100%, 70% and 40%), with minimum delays in smoothed output. Statistical and optimization analysis from the data gathered for these tests will determine both the optimal amount of smoothing needed and the associated battery capacity.
- The effectiveness of using data from either the PV meter or the irradiance sensors for smoothing was determined, showing that the PV meter data is more effective.
- The manual test successfully demonstrated the predictive quality of the shifting algorithm, and PNM subsequently automated the shifting process by embedding the algorithm in PNM's advanced calculation engine (ACE). A test of the automated system was successful, dispatching constant power during a period between 2:00pm and 6:00pm. Ultimately, PNM plans to displace ACE with a distribution management system (DMS) with storage control capability, but such a system is not yet available.
- Simultaneous shifting and smoothing was accomplished on a day with intermittent sunshine. Although the power was not as smooth as ultimately desired by PNM, as shown in the graph below, during a period of two hours the smoothing results were good and the concept of being able to provide multiple benefits simultaneously was proven.



Simultaneous Shifting and Smoothing Test Results

Key: —Total system output —Battery output —Solar output

A rigorous test plan will continue into early 2014, including analysis of optimal voltage levels.

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 20 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 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

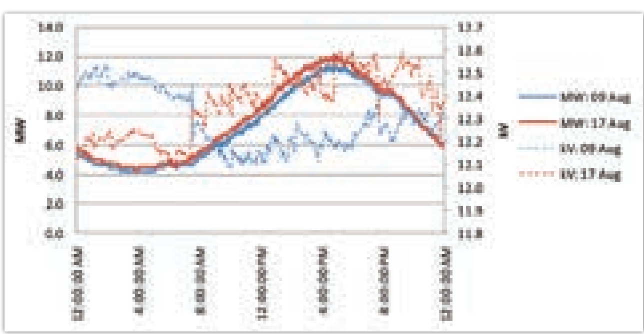
The following are the hypotheses for the CVR/VVO project:

- 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.

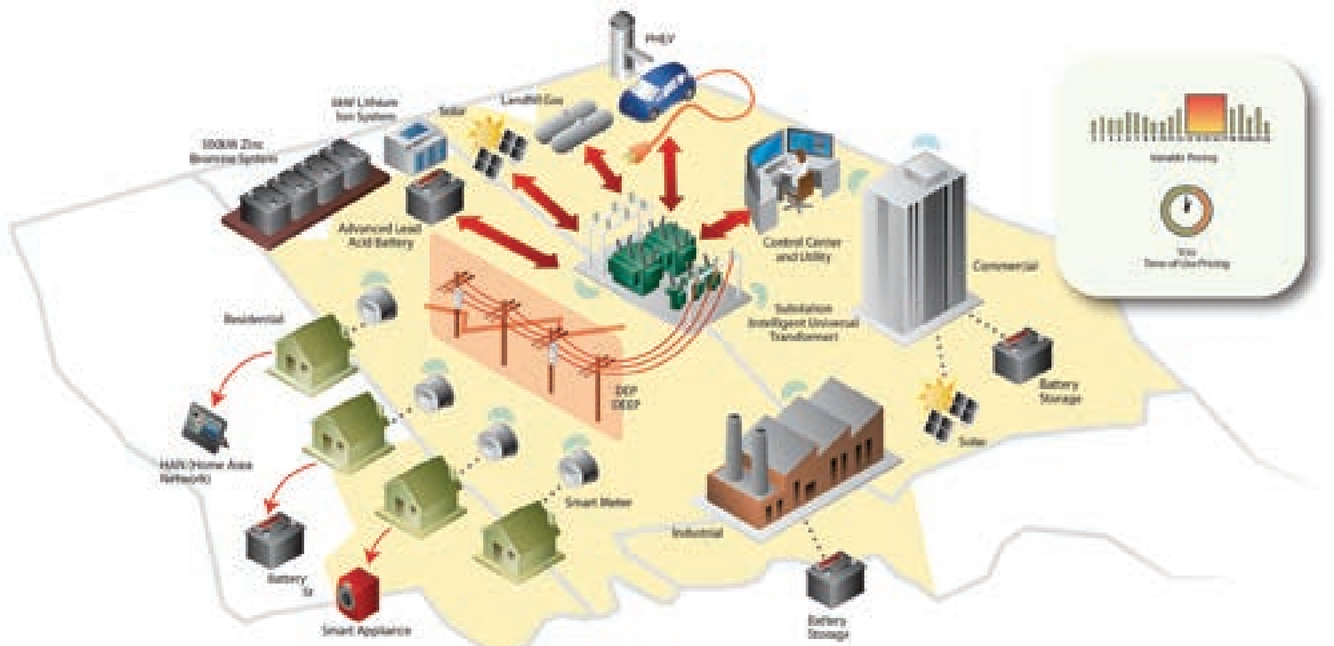
The VVO control logic was demonstrated and the changes in the control logic confirmed via measurement. The final control logic maintained overall power factor between 0.95 leading and unity on the low side of the substation transformer for both the Madison-Kenneth and Myrtle-Date substations.

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.

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.

Southern Company Case Study on 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.

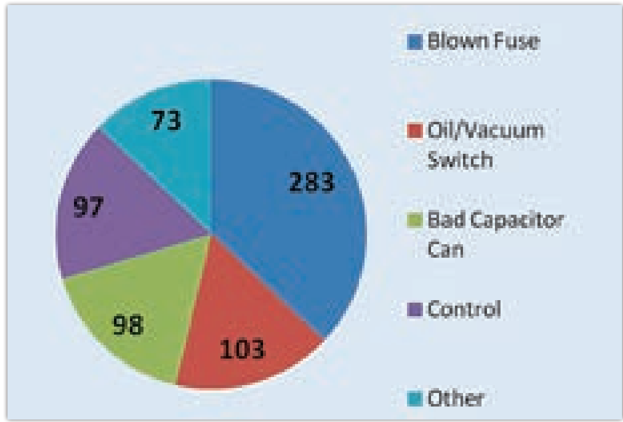
Results

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.

Deliverables

2012 Smart Grid Deliverables

2012 Duke Host Site Progress Report
Product ID 1025571

2012 Grid Strategy: DMS Advanced Applications for Distribution Energy Resources
Product ID 1025572

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Product ID 1025570

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Product ID 1024498

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Product ID 1023411

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Product ID 1025758

Field Data Integration for Asset Management and Grid Operations: A Paper on EPRI's Coordinated Research
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Product ID 1025764

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Product ID 1024839

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

Kansas City Power & Light Company Smart Grid Host Site 2012 Progress Report
Product ID 1025759

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Product ID 1025760

Strategic Intelligence Update: Smart Grid Conferences and Events October 2012
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Commonwealth Edison: The Effect on Electricity Consumption of the Commonwealth Edison Customer Application Program Pilot: Phase 1, Appendices
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Product ID 1021421

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Product ID 1021488

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Product ID 1020597

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Product ID 1021419

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Assessment of Wholesale Market Opportunities for Participation and Aggregation of Distributed Resources
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Project ID 1020213

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Con Edison Smart Grid Demonstration Host-Site Project Description
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Distributed Resource Integration Framework
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Product ID 1020189

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

Smart Grid Demonstration Overview
Product ID 1020225

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

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

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

The EPRI Smart Grid Demonstration Initiative Team

Matt Wakefield

Matt Wakefield is Senior Program Manager at the Electric Power Research Institute (EPRI) managing EPRI's Smart Grid and IntelliGrid Programs. He has over 24 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.

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.

John Simmins

John Simmins is Senior Project Manager 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.

Brian Green

Brian D. Green is a Project Manager at EPRI. He is managing the Kansas City Power & Light, Ergon Energy, and Ameren Smart Grid Demonstration Projects, and smart grid training efforts. Brian manages EPRI's Use Case Repository, and is the contact for use case development and use case training for our members and non-members. Brian's background is in substations and communications.

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Dennis Symanski is a Senior Project Manager at EPRI, supporting the Southern California Edison Irvine Smart Grid Demonstration. He is also involved in power quality standards and energy efficiency research for data centers. He has a BS in Electrical Engineering and an MS in Electric Power Engineering and is a senior member of the IEEE and a registered Professional Engineer.

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 Haddad

Christina Haddad is a Technical Research Assistant in the Smart Grid Program of 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 Smart Grid Demonstration 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.

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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 degree from the University of Alabama in Birmingham.

Robin Pitts

Robin Pitts is a Senior Administrative Assistant with EPRI, supporting Matt Wakefield, Senior Program Manager, for Smart Grid, IntelliGrid and Cyber Security Programs. Within EPRI's Power Delivery and Utilization group, Robin has supported these programs for 6 years with contracts, departmental budgets, event coordination and professional administrative resources.

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