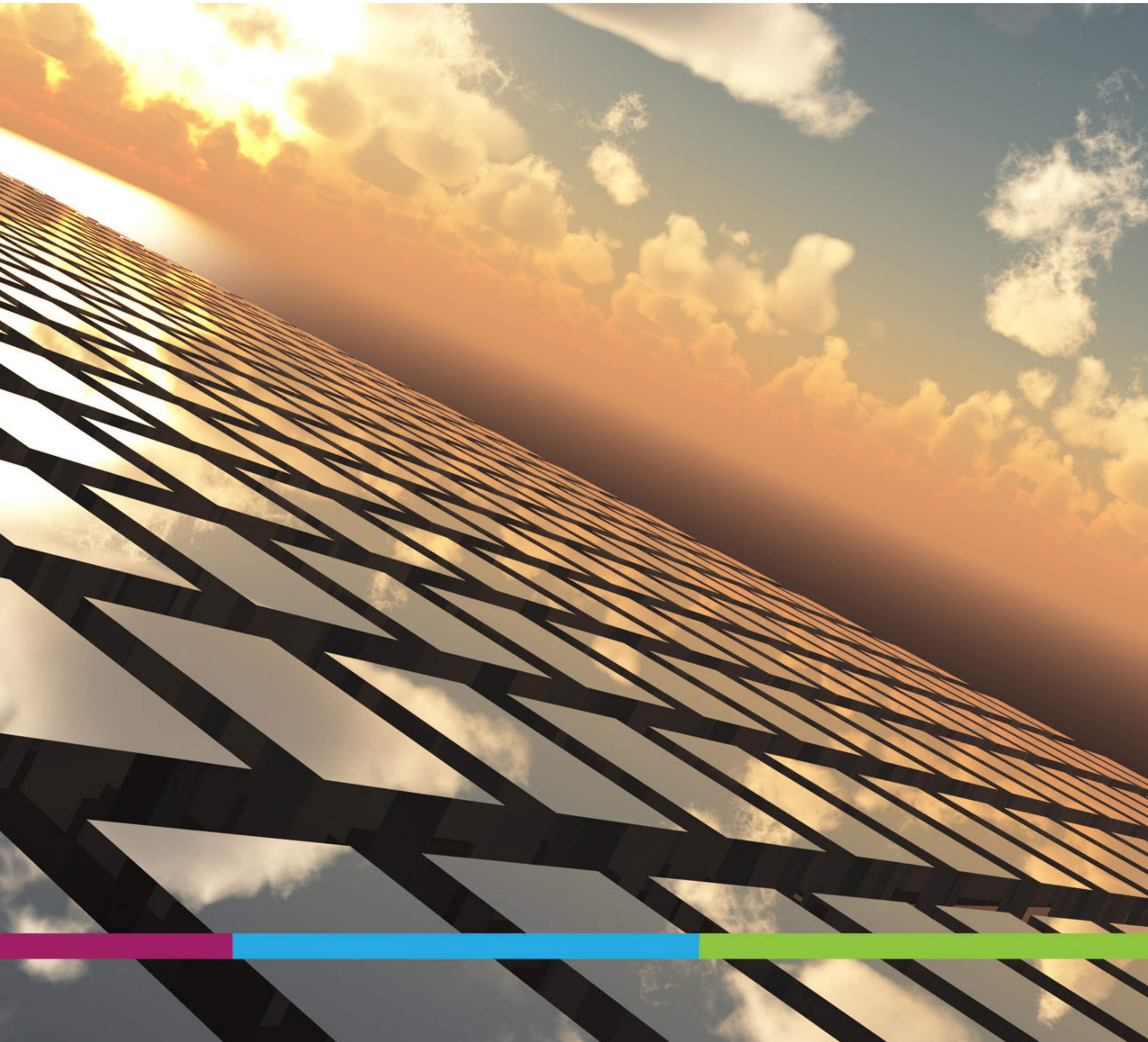
Pacific Northwest
SMART GRID
DEMONSTRATION PROJECT

TECHNOLOGY PERFORMANCE REPORT

Highlights



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Director's Message

Experiments allow us to probe the unknown. They help uncover new, useful knowledge or, conversely, confirm for us that more work or a different approach is needed to obtain the discoveries and solutions we need. Although not carried out in a traditional laboratory, the Pacific Northwest Smart Grid Demonstration Project was a grand experiment, delivering useful results that will help shape future smart grid activity in our nation.

Battelle has been pleased to lead this ambitious $178 million, five-year effort from beginning to end. We are grateful for the contributions of all the project partners, but particularly appreciative of the Bonneville Power Administration (BPA). BPA provided the initial thinking behind the demonstration project's concept, which led to a successful proposal. As tasked by the U.S. Department of Energy (DOE), the demonstration project sought to advance knowledge and understanding of smart grid approaches and technologies. The work helps set the stage for grid modernization—an effort that by all accounts will take years and trillions of dollars, but will be exceedingly worthwhile, substantially updating the nation's energy system.

The journey has been exciting and highly challenging. It was not an entirely new effort—we were building on the earlier GridWise® Olympic Peninsula demonstration. But no previous project has tackled the breadth and scope of implementing and testing a new smart grid technology called transactive control. Developing and demonstrating this innovative approach for coordinating distributed energy resources at multiple utilities was one of the major successes of the project. Our team showed that regional transactive control can be done, and that assets (e.g., smart systems and devices) at the end points can respond dynamically on a wide scale. You'll read more about the transactive system later in this document.

Like any demonstration project of this size and nature, we worked our way through unanticipated and perplexing technical issues and challenges. But we also experienced rewarding accomplishments, learned a lot, and achieved some really great outcomes, a few of which include:

- **Improved Northwest grid infrastructure**—Much of the $80 million in technologies and equipment that were installed through the demonstration project will remain in place, benefitting consumers now and facilitating future smart grid deployment.
- **Enhanced regional collaboration**—The project brought together a team of technology companies, utilities, universities, researchers, BPA and others that will undoubtedly continue to collaborate and bring value to regional grid modernization.
- **Important lessons learned**—By understanding existing challenges and identifying the areas where more research, resources or attention are needed, we expedite smart grid development.

In lieu of the annual reports the demonstration project has produced in past years to chronicle our progress, we developed this document to summarize, at a very high level, the content of the Technology Performance Report (TPR). The TPR is the project's final comprehensive and detailed report for DOE, the agency that provided half of the funding for the demonstration. In this summary document, you'll gain a sense of the projects executed by the demo partners and the associated outcomes. You'll also see a few items that are not in the TPR, such as photos from various project events, that we wanted to share.

Battelle and the other participants in the demonstration project are pleased and proud to have been a part of a monumental effort that reflects the unique grid-related capabilities—and ingenuity—of the Pacific Northwest. I have no doubt that this project and the knowledge that has been gained will help prepare the region—and the nation—for a bright energy future that strengthens our economy, protects our environment and enhances our quality of life.

Ron Melton, Project Director

Pacific Northwest Smart Grid Demonstration Project

By the Numbers

A brief look at some of the project's accomplishments.

$80 **million+** in technology/equipment installed (88 percent remains in place)

AMI smart meters installed

30,696

(27,376 residential, 2,961 commercial, 359 industrial)

97

percentage of Flathead Electric Cooperative survey respondents saying they were pleased overall with their experience in the demonstration project, would be willing to take part again, and would recommend it to others

310

estimated number of individuals within the partner organizations who contributed, at various levels of support, to the execution of the demonstration project

12,822

feeder monitors installed for identifying fault locations

200+ smart meters

now acquire near-real-time data about University of Washington campus energy consumption every 5 to 15 minutes (previously there were seven meters)

14

the number of new smart grid test and certification products directly and indirectly resulting from the demonstration project (developed/introduced to industry by QualityLogic)

350 billion

approximate number of data records generated by the project, which will be available for future research

A tree, a squirrel and a magpie nest:

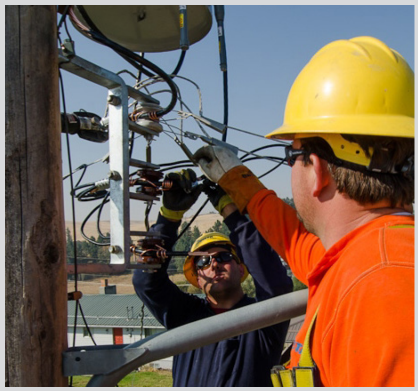
sources of three power outages in Helena, Montana—customer outage minutes were reduced with NorthWestern Energy's new Fault Detection, Isolation and Restoration (FDIR) software

Pacific Northwest Smart Grid Demonstration Project

Through the Years

A visual perspective of some of the project's regional events and activities.

Sen. Patty Murray (D-Wash.) speaks at the October 24, 2012, Go-Live event at the University of Washington to mark the start of phase three of the demonstration project.



Avista personnel install smart transformers to help improve the efficiency of the Pullman distribution system.

In a step toward establishing the demonstration project's transactive system, in April 2011 engineers from the Bonneville Power Administration and Alstom Grid successfully established a digital data connection to the Electricity Infrastructure Operations Center (EIOC) at Pacific Northwest National Laboratory. A week later, 25 participants from four of the project's technology firms also demonstrated this connection at the EIOC and conducted additional testing.

Patricia Hoffman (left), DOE Assistant Secretary, Office of Electricity Delivery and Energy Reliability, Sen. Ron Wyden (D-Ore.), second from left, and BPA Administrator Elliot Mainzer (fourth from left), were among those who toured Portland General Electric's Salem Smart Power Center at the center's opening on May 31, 2013.

During a panel discussion at the grid demonstration project's Regional Symposium on April 1, 2015, in Spokane, Wash., Teri Rayome-Kelly (right) shares examples of Flathead Electric Cooperative's grid demo experiences. Other panelists are, from left, Mark Reed (Idaho Falls Power) and Curt Kirkeby (Avista).

The demonstration project's Regional Symposium on April 1, 2015, in Spokane, Wash., provided opportunities for discussion about project outcomes. In the foreground, from left, the demonstration project's director, Ron Melton, and Sen. Maria Cantwell (D-Wash.) talk with Seabourne Consulting's Ed Carroll in the symposium's exhibit area.

Rep. Cathy McMorris Rodgers (R-Wash.) tours the exhibit area of the demonstration project's Regional Symposium on April 1, 2015, in Spokane, Wash.

Project Overview

The five-year Pacific Northwest Smart Grid Demonstration Project was initiated in 2010. It was one of 16 smart grid demonstration projects co-funded by the U.S. Department of Energy (DOE) under the American Recovery and Reinvestment Act of 2009, and was conducted across a five-state region: Idaho, Montana, Oregon, Washington and Wyoming.

Battelle led the project, collaborating with the Bonneville Power Administration (BPA), technology infrastructure providers and field demonstration partners (including rural electric cooperatives, public utility districts, municipalities, independent utilities, and a university campus).

In addition to Battelle and BPA, the project participants were:

Technology Infrastructure	Field Demonstration
Alstom Grid	Avista Utilities (Washington)
IBM	Benton PUD (Washington)
Netezza (now part of IBM)	City of Ellensburg (Washington)
QualityLogic	Flathead Electric Cooperative (Montana)
Spirae	Idaho Falls Power (Idaho)
Vaisala (previously 3TIER)	Lower Valley Energy (Wyoming)
	Milton-Freewater City Light & Power (Oregon)
	NorthWestern Energy (Montana)
	Peninsula Light Company (Washington)
	Portland General Electric (Oregon)
	University of Washington (Washington)

The project's budget was $178 million; half was provided by DOE, and half by the project partners. Key project objectives were to:

- Create the foundation of a sustainable regional smart grid that continues to grow following the completion of the project.
- Develop and validate an interoperable communication and control infrastructure using incentive signals to: coordinate a broad range of customer and utility assets, including demand response, distributed generation and storage, and distribution automation; engage multiple types of assets across a broad, five-state region; and reach from generation through customer delivery.
- Measure and validate smart grid costs and benefits for customers, utilities, regulators, and the nation, thereby laying the foundation of business cases for future smart grid investments.
- Contribute to the development of standards and transactive control methodologies for a secure, scalable, interoperable smart grid for regulated and non-regulated utility environments across the nation.
- Apply smart grid capabilities to support the integration of a rapidly expanding portfolio of renewable resources in the region.

BPA provides leadership and contributions to grid demonstration project

The Bonneville Power Administration played a central role in multiple aspects of the Pacific Northwest Smart Grid Demonstration Project. The project grew out of previous collaborations between BPA and Pacific Northwest National Laboratory on the Olympic Peninsula's GridWise® Demonstration. Recognizing future challenges facing the Northwest, BPA facilitated involvement of their customers and other utilities in the region in formulating this project and its objectives in order to provide opportunity to continue to develop and apply transactive system technology.

BPA has an industry-leading Technology Innovation Program that provided $10 million in cost share (making the demonstration the largest project in the TI Program's portfolio). In addition, the agency contributed project management support, delivered near-real-time data feeds to the project's regional modeling effort, and helped to tell the demonstration project's story regionally and nationally through outreach and communications efforts. Project management would like to thank BPA, its leadership, and staff who participated in the demonstration project for their many outstanding contributions.

BPA-developed informational materials about the demonstration project are available at:

Platform for a Modern Grid: Engaging the Customer (video)
https://www.youtube.com/watch?v=fBaV8Zu6Dr0&feature=player_embedded

Grid Gets Smarter with Nation's Largest Test (video)
https://www.youtube.com/watch?v=LCvhbg76PEo

Demonstration Project Success Stories (booklet)
http://www.bpa.gov/Projects/Initiatives/SmartGrid/DocumentsSmartGrid/A%20Compilation%20of%20Success%20Stories.pdf

Transactive Coordination System

The Pacific Northwest Smart Grid Demonstration Project's transactive system has been described as a "glue." Indeed, the system was the centerpiece of the demonstration, connecting and testing many of the project's individual components and providing insights as to the new technology solutions that will be needed to achieve a smart grid.

The transactive system was based on the transactive control concept formulated at Pacific Northwest National Laboratory. Under transactive control, decision-making is distributed across the grid, even to consumers and individual devices. This is accomplished via a seamless, two-way communication method that uses signals containing information about the delivered cost of electricity and the amount of power needed by end users. The two-way communication of this information—all the way from sources of electricity, such as dams or wind projects, to homes—allows consumers and devices (smart appliances, etc.) to make informed energy use decisions. This, in turn, benefits the region, utilities and consumers through improved grid efficiency, cost effectiveness and reliability.

The demonstration project's innovative transactive system was designed to coordinate the dispatch of electric energy with responsive electricity demand in a way that reduced power usage peaks, reduced costs, and mitigated the challenges of integrating intermittent energy resources like wind. The system partitioned the Pacific Northwest power grid into 27 "nodes," or points in the power system that can send and receive information. When in operation, the nodes communicated two types of information with their nearest neighbor nodes every five minutes: 1) the delivered cost of electricity (incentive signal) and 2) the predicted energy to be exchanged now and during a set of future intervals (feedback signal).

Throughout this document, but particularly in the utility reports, there are multiple references to "events"—these often refer to the engagement of "assets," such as the participating utilities' smart appliances, power generation sources, and energy storage units, by the transactive system.

The transactive system contained eight functions that were central to achieving and demonstrating useful outcomes. The demonstration project's Technology Performance Report discussed how successful the system was toward making these functions happen; the following provides a brief summary of subsystem objectives and performance:

Subsystem & Objective	Performance
Energy resource dispatch: The system must accurately represent the region's strategies for the dispatch of its energy resources. For the system to accurately communicate its incentive signal to power users, there must be a faithful representation of the availability and mix of resources (hydropower, wind energy, thermal, etc.) in a given location, as well as any grid conditions, such as an outage, that would alter the mix.	The transactive system represented the actual statuses of regional generation and transmission, where such data was made available to it. The system achieved superior visibility of actual and predicted wind power resources, and also appears to have identified an unexpected outage at a large power generator. The system did not accurately represent and respond to transmission events, including line outages and actions taken to keep loads under capacity limits. This could be corrected through more detailed design of the system's transmission model.
Resource monetization: The system must meaningfully monetize—put a price tag on—electricity costs and the incentives represented to energy users.	The demonstration project used an "informed simulation" approach to emulate the dispatch of generation resources (hydropower, wind, etc.) and their impacts on the delivered costs of electricity. Also, "toolkit functions" were developed and worked in conjunction with the informed simulation, specifying how much of each type of dispatched energy was to be modeled in the system and the given resource's impact on the delivered costs of energy. The demonstration project successfully reproduced power and costs introduced by each resource. The costs of infrastructure were included in the incentive signal. The project was less successful in factoring in BPA's objective for improved integration of wind power, and in the implementation of an incentive function for the mitigation of transmission congestion. Demand response incentive functions were more successful, but improvements are needed.

Energy costs/incentives: Energy costs and incentives must be meaningfully blended and distributed throughout the transactive system.	The demonstration project's equation for blending and distribution of energy cost influences in the transactive system offered flexibility to represent the costs of energy resources while also incentivizing desirable dynamic energy behaviors. However, the modeling methodology for infrastructure costs led to an undesirable outcome—that of discouraging energy use when less energy was being generated and consumed. This later was corrected through use of an alternative representation of those costs in the equation.
Responsive loads/incentive signal: The responsive loads in the system must be able to allocate their responses and events, based on the incentive signal and local conditions. For example, can a system of responsive assets, such as water heaters, select no more than five useful periods to temporarily curtail energy usage each month, as promised to customers?	The demonstration project designed three toolkit functions to help asset systems effectively use the incentive signal to schedule curtailments or other responses: **event-driven** (assets respond, for example, to monthly peak power use periods); **daily** (assets respond to daily peaks in the transactive incentive signal), and **continuous** (continually seeks opportunities to use both low-cost and high-cost periods to strike a beneficial tradeoff between electricity use and load reduction). The three toolkit functions proved effective, applicable and flexible for a variety of assets. The transactive system successfully determined event periods based on the incentive signal and other local conditions.
Responsive loads/impacts: Responsive loads (consumers/devices using or curtailing use of electricity) must accurately predict the energy impacts of their responses. Presuming event periods are well selected by the toolkit functions and that the assets do indeed respond to the events, do the asset models accurately predict total load and the impact of the events on "elastic load" (an elastic load can alter energy consumption in response to incentive signals)?	The demonstration project evaluated asset model algorithms and configurations to determine prediction accuracy. Relative prediction error analysis revealed multiple prediction biases, where the transactive system was found to have under- or over-predicted the final load prediction for the given data interval. Most of the utility sites predicted their loads well up to a day or so into the future, but some of the bias errors were significant even for near-term predictions. As for elastic load, some model algorithms were not configured properly, which would misrepresent the impacts of the asset systems. Improvements are needed in predictive algorithms and asset model configurations.
Power exchanges: The exchanges of power with the system must be calculated and communicated throughout the transactive system. The transactive feedback signal is central to this function, as it was designed to predict and state the electrical power to be exchanged between nodes in the system.	The system reliably exchanged its transactive signals, including the transactive feedback signals. These signal values were calculated as planned at the utility nodes, although the accuracy of those predictions may be further improved. More research is needed to insert distributed power-flow calculations into transactive systems at this grand scale.
Power exchange accuracy: Plans to exchange energy with the transactive system must be accurate. Did the feedback signal at a node accurately represent the power being exchanged by the connected nodes?	The demonstration project's modeling of its electric load was probably not accurate enough for transactive systems of the design used in the demo. The relative errors between the feedback signal values at site nodes—and the metered power that the feedback signal values should have modeled—were found to be large. There needs to be an emphasis on developing systems to track and predict loads, metering those loads, and making the resulting data available to the transactive prediction algorithm in real time. Incentives will need to be built into future transactive systems to reward accuracy and deter inaccuracy.
Supply resource responses: Supply resources must respond to dynamic system load prediction, including the plans from flexible loads. Do predicted loads—both the predictions for inelastic and responsive elastic load in the transactive system—affect the actual dispatch of bulk load in the region?	The demonstration project's transactive system was not large enough to directly influence bulk generation in the region. Recognizing this, technology partner IBM developed a simulation to help the project scale up the modeled penetration of transactive assets and to close the control loop so that the connection between assets' responses and the dispatch of regional resources could be tested. Among the results: Total load and total incentive costs were observed in the simulations to have decreased as the daily peak incentive costs were occurring; a smaller increase in load and incentive costs was observed as modeled battery systems reacted when minimum daily incentive costs were occurring; and there was a complex interaction between dynamic wind power and these impacts within the transactive system as the wind power dynamically affected incentive values.

Based on the transactive system testing and performance, the demonstration project identified recommendations for improving the development of future transactive systems. Among the recommendations:

- Many more responsive assets are needed. The changes in power offered by a system's responsive assets must be comparable in total magnitude to the changes in power available today from the supply side.
- More flexibility should be available from each asset. Today's demand response programs and their assets allow for only several brief events each month. These programs might address peak demand, but are otherwise limited in the services they can provide.
- The project's transactive signal exchanges were based mostly on timed 5-minute intervals. The growing consensus among demonstration project partners was that future systems should instead be more event-driven (e.g., waiting until the power system has appreciably changed or until predictions have become inaccurate).
- There needs to be an incentive function that represents transmission congestion impacts on energy costs. Such a function would help dissuade downstream energy consumption as transmission approaches a stressful capacity.

Final Observations

Among the successes of transactive system testing:

- Wind resources were accurately stated and predicted within the region
- Unit costs and incentives were indeed generated to represent bulk resource costs and the demonstration's stated operational objectives
- The incentive signals were meaningfully blended at, and communicated between, the system's multiple nodes
- A library of functions was developed that automatically determined times of events to which responsive demand-side assets, such as water heaters, battery energy storage, and thermostats, were to respond.

The transactive aspect of the project is unique in the world. In principle, a system of this type might eventually help coordinate electricity supply, transmission, distribution, and end uses by distributing mostly automated control responsibilities among the many distributed smart grid domain members and their smart devices.

At the end of the project's data collection period, the transactive system was turned off. The regional incentive signals produced using the Alstom tools were not linked to operational needs of BPA, the regional system operator. In the absence of such linkage, there was no basis for continuing to generate the signals once the research was completed. There are efforts underway to continue to use a small subset of the deployed transactive control system for further regional research. If BPA or other balancing area operators in the region define an incentive signal, the demonstration project utilities could, in principle, resume the use of their transactive systems.

Technology Partners

The grid demonstration project's diverse team of Project-Level Infrastructure Providers (PLIPS) was central to project execution. The partner organizations brought not only cost-share investments to the project, but delivered a wide range of technology and expertise—from designing the transactive coordination system to providing transmission and generation system modeling. Further, participation in the demonstration project helped the PLIPs to bring new thinking to current approaches, which will benefit future smart grid efforts. The technology partners and their involvement are summarized below. Note: Netezza was one of the original technology partners, but later the company became a part of IBM.

Alstom Grid

Alstom Grid is a sector within Alstom, a global company focused on power generation, transmission and distribution, as well as rail infrastructure. Specific to the grid, Alstom develops innovations to advance a flexible, reliable, affordable and sustainable electrical grid, and supports more than 25 smart grid projects worldwide. Alstom Grid's center of excellence for its control center software is based in Redmond, Wash., making the company a key Pacific Northwest grid technology partner.

Alstom Grid viewed the demonstration project as an opportunity to help develop transactive control across multiple layers of a complex grid. The project also aligned with Alstom Grid's culture of testing new analytical techniques and tools within a collaborative framework. The company's contributions to the project included:

- Real-world data feeds were collected for regional wind forecasts from Vaisala (previously 3TIER), and for power system data (including load forecast, generation and transmission schedules) from the Bonneville Power Administration.
- The company applied its powerful analytical engine to the data and derived forward costs of generated energy and predicted regional energy flow. Such an "informed simulation" predicts, for a four-day period, how the system would behave if generation is dispatched to meet the load and respect transmission constraints at the lowest cost.
- Once costs/flows were calculated, they were sent as signals to transmission zones, and then were propagated down through the project's transactive system to participants.

The use of real-time regional power system information to produce forecasts for the future state of the system was an essential component of the demonstration project's transactive signal that many of the project tests were based on. Additionally, Alstom Grid provided a tool to help visualize real-time and historical regional generation and power flow patterns and their relationship to the transactive signals produced.

IBM

IBM works with energy and utility companies around the globe to help them develop smarter energy capabilities to enable tomorrow's grid. IBM helps organizations compete, engage and optimize by assuming the role of the energy integrator, delivering a 360-degree customer-of-one experience, and optimizing business by disruptively innovating business processes through analytics-driven operational excellence. From asset and workforce management solutions to smart metering, grid operations, distributed energy solutions and beyond, IBM leverages the power of analytics, cloud, mobile, social and security to help improve operational efficiency and reliability, reduce costs and increase customer satisfaction.

IBM was a participant in an earlier project—the GridWise® Olympic Peninsula Demonstration in Washington state, which ran from 2005 to 2007. As that activity concluded, IBM was one of the advocates for a larger-scale demonstration to extend the concepts and technologies from the peninsula project to a broader region. The five-state grid demonstration offered that opportunity, and in this project IBM has been the chief system architect.

During the demo, IBM implemented the ISO/IEC 18012 standard, which served as the foundation for developing the transactive node agent design and the transport independent event communications model, which are vital to coordination of demand response. Associated with this, IBM was highly involved in the implementation of the project's core regional system—including the detailed transactive node design, the data collection subsystem, the system management subsystem, and the toolkit functions. IBM also implemented the simulation system used to perform scale-up analysis at the end of the project. The company continues to see great promise in transactive energy management and transactive control, and to promote these ideas worldwide.

QualityLogic

QualityLogic Inc., headquartered in Boise, Idaho, provides quality assurance test tools and test/engineering services for interoperability, compliance and performance testing in digital imaging, telecommunications, web, mobile and smart energy markets.

For the grid demonstration, QualityLogic contributed its expertise, tools and processes on several fronts, including:

- test tools and processes to ensure transactive control interoperability

- transactive control interfaces to OpenADR, MultiSpeak and IEC 61850 industry standards
- assistance with data collection, quality, analysis and visualization—to ensure accuracy and completeness
- promotion of standards for transactive control/energy through publication of papers and co-leadership of the demonstration project's standards working group
- a set of visualization tools for analyzing the massive amounts of project data, developed in partnership with Seabourne.

QualityLogic viewed its participation as a strategic business opportunity and a chance to establish relationships with thought leaders, expand availability of smart grid products and services, and help advance transactive energy and realize the promise of a smart grid. Fourteen new QualityLogic smart grid test and certification products resulted from the demonstration project and will help advance smart grid objectives. Another outgrowth of the project in which QualityLogic has been involved was the creation of Smart Grid Northwest. The organization now has over 60 members and has hosted two international transactive energy conferences.

A key deliverable QualityLogic developed for the project was an updated technical Design Specification for Transactive Control and a reference implementation built on Pacific Northwest National Laboratory's VOLTTRON™ platform. The resulting reference implementation can serve as a platform for transactive energy research in the broader industry, and PNNL and QualityLogic are working to make the platform available to qualified researchers.

Spirae

Spirae, based in Fort Collins, Colo., is a technology firm focused on scalable smart grid solutions for global partners and customers. The company specializes in the integration of large-scale renewable and distributed energy resources, the development of local and wide area controls, energy service platforms and power system simulations. Spirae viewed participation in the demonstration project as a great opportunity to collaborate with key regional transmission and distribution stakeholders, validate its own technologies and help advance the transactive control concept.

During the demonstration project, Spirae deployed its BlueFin® (now Spirae Wave™) platform at four partner sites—Avista Utilities, Flathead Electric Cooperative, Idaho Falls Power and the University of Washington. The platform translated the transactive energy signal to engage distributed energy resources. BlueFin® also coordinated systems, including in-home displays, water heaters, smart appliances, conventional generation, conservation voltage reduction and building management systems. Spirae also worked with NorthWestern Energy to support its data collection efforts, as well as additional demonstration project partners to help ensure their systems could communicate with QualityLogic's testing framework.

As a result of the demonstration project, Spirae achieved proof of concept in three areas: implementation of transactive control nodes for distribution utilities; prediction of response of distributed resources to trigger events; and engagement of distributed resources for participation in transactive events. Spirae also identified areas to optimize its Wave™ products for future smart grid applications, and is building upon its demonstration project experience through implementation of designs that minimize custom work and improvements in performance, usability and standard applications.

Vaisala (formerly 3TIER)

Vaisala is headquartered in Vantaa, Finland, and maintains offices worldwide, including in Seattle, Wash. The company offers a range of observation and measurement products and services for chosen weather-related and industrial markets.

For the demonstration project, Vaisala provided renewable energy forecasts. The goal of such forecasts is to help integrate the most renewables onto the grid in the most cost-effective way, while maximizing carbon reduction. This objective is achieved when fast, flexible systems and markets receive accurate forecasts of variable generation. In addition to providing the forecasts, Vaisala collaborated with project partners in integrating that information into the transactive control signal.

Vaisala provided forecasts for all of the installed wind energy capacity interconnected to the Bonneville Power Administration and over 99.5 percent of the installed wind energy capacity in the study area as a whole. Over the life of the project, the amount of installed wind energy capacity in the study area as a whole grew by approximately 3.5 gigawatts.

Vaisala's work on the project confirmed that there are three important ingredients that are critical to the successful integration of wind and other renewables:

- Visibility—Data transparency and real-time availability
- Flexibility—a flexible system, i.e., a smart grid
- Forecastability—Upon achieving visibility and flexibility, there is a need for accurate, state-of-the-art, project-level and balancing area forecasts from multiple sources to allow the system to become proactive and to optimize system response to actual and expected variability.

Utilities and Project Outcomes

Avista

Avista Utilities is an investor-owned utility, based in Spokane, Wash., that serves about 680,000 customers over 30,000 square miles. The service area includes eastern Washington, northern Idaho and parts of southern and eastern Oregon. In 2014, the utility celebrated its 125th anniversary.

Demonstration Project Focus

Avista invested in modernization of the Pullman, Wash., distribution system. Pullman is the home to Washington State University (WSU), which also participated in the demonstration.

The utility's projects included the following asset systems:

- Volt/VAr (volt-ampere reactive) optimization
- Reconductoring
- Smart, efficient transformers
- Communicating thermostats
- Completion of advanced metering infrastructure (AMI)
- Fault detection, isolation, and restoration (FDIR) and other reliability enhancements
- Cooperative control of WSU facilities
  - heating, ventilation, and air conditioning (HVAC) air handlers
  - chiller loops
  - diesel generator
  - two natural gas generators.

Avista's Cost Share: $19 million

Projects/Results at a Glance

Project Description	Outcomes
Volt/VAr optimization: Avista installed an integrated volt/VAR control (IVVC) system to optimize voltages and improve power factors in Pullman electricity distribution feeders. One purpose was to manage distribution voltages to conserve power while maintaining satisfactory service voltage levels. After lowering distribution system voltage, some electric loads consume less power, often resulting in energy conservation. Additionally, power factor correction allows the same power to be supplied with less distribution line current, thus reducing power losses due to resistive lines.	Following testing and data collection from April 2012 through August 2014, it is estimated that electricity savings from *continuous* application of the Volt/VAr system across all 13 Pullman feeders could amount to 2.1 percent—slightly higher than original estimates. There also were indications that line losses were reduced on some feeders by a small percentage. Based on the findings, Avista plans to enhance feeders with the IVVC throughout the service territory as part of its grid modernization investments. It's believed voltage optimization could save the utility $500,000 annually for the Pullman feeders.
Reconductoring: Power lines on approximately one mile of key feeder segments in Pullman were replaced to reduce system losses and provide operational flexibility.	Reconductoring was completed in October 2010. Avista calculations indicate that up to approximately 30 megawatt hours can be saved on the two feeders annually—which translates to modest savings of less than $3,000. However, in the absence of the upgrade, the capability of new distribution automation features in Pullman might have been constrained.
Smart, efficient transformers: Avista replaced approximately 380 of Pullman's 1,200 distribution transformers with smart transformers, which were equipped with advanced sensors and telemetry for the remote measurements of voltage, current, and transformer temperature. The new transformers were expected to provide a constant reduction in load and no-load electricity losses, support the volt/VAr optimization system, help detect electricity theft and monitor transformer temperature, which could help avert power outages.	It was initially believed the transformer upgrades could perhaps lead to annual energy savings equivalent to 130 kilowatts, the power usage of about 50 homes—or approximately $111,000. The demonstration project was unable to confirm the estimated savings.
Communicating thermostats: The utility launched a residential load response program in Pullman involving installation of smart thermostats in test residences. As envisioned, the thermostats, during transactive system events, could be controlled up or down, resulting in potentially significant reductions in power use. Also, the thermostats would provide useful energy consumption information to customers via a consumer interface feature. Various incentives were offered to prospective volunteer participants. The program initially sought to recruit 1,500 residences, and developed a detailed communications approach focused on customer education/participation and energy management.	The number of eventual participants—75—was much lower than hoped. Participation was impacted by several factors, including a narrow eligibility criteria that served to substantially reduce the potential pool of candidate homes. Through the recruitment process, the utility learned that personal contact was the best approach for gaining customer involvement. An Avista customer survey found that nearly 90 percent of participants were very satisfied with the smart thermostat program. Further, data suggests the smart thermostats reduced energy consumption during advised transactive events, but the impact was small.

Completion of AMI: Existing electric (14,000) and gas (6,000) utility meters in Pullman were replaced with advanced meters. The project included installation of a radio frequency mesh network to communicate with the new devices. The meters are read remotely, provide customers with usage information, help the utility identify fault locations, facilitate power theft detection and can reduce the amount of "truck rolls," or dispatches of service personnel to check on meters. An associated web portal provides a wealth of information for customers. In addition to the meters, 1,500 customers received in-home display units to view electricity usage in real time, which also promotes consumer involvement in power consumption.	Change in energy consumption for residential customers who had been granted access to information from an energy web portal was not significant. A small reduction of about 0.7 percent was found, but the result was not statistically significant. Avista internally assessed and estimated dollar savings from the new system as totaling $235,000 annually. Cost reductions would result from meter reading and customer service savings, and fewer service calls.
Fault detection, isolation and restoration: FDIR was implemented within Avista's distribution management system to help rapidly detect faults and improve the outage recovery process. Avista installed switchgear, distribution line switches, smart circuit reclosers, and smart fault circuit indicators. The utility anticipated a decrease in their outage response times for some outages.	The FDIR system was fully automated by August 2013. It could not be verified by the demonstration project that the new system, or any other distribution management practices, significantly impacted the customer outage durations. However, Avista created a new metric that captures the avoided outage minutes that would have been experienced by customers had the technology not been in place. Avista reported substantial improvements in reliability with 353,336 avoided outage minutes for customers between August 2013 and December 2014. Customers also experienced an annual average of 17 percent fewer outages and more than 12 percent shorter outages during the same time period. Avista believes a lack of severe weather-related outages during the grid demonstration project prevented full exercising of the FDIR system.
Controllable HVAC fan load at 39 WSU campus buildings: It was estimated that daytime electricity load could be reduced by changing the operation of WSU campus heating, ventilation and air conditioning circulation fan systems. Also, WSU planned to cycle through available HVAC fan loads upon receiving demand response control signals from Avista for short periods of time. It was believed that total fan loads could be reduced about 25 percent without adversely affecting building air quality.	It was confirmed that significant load reduction accompanied reduced campus HVAC fan loads. The magnitude of the power reduction closely matched initial predictions. Avista estimates energy use may be reduced on the order of 1,500-3,000 megawatt hours per year—which translates to savings ranging from $87,500 to $175,000.
Nine WSU controllable chiller loads: Nine WSU building chiller (facility cooling) loads were identified to receive demand response control signals from Avista. Loads can be deferred without affecting occupant comfort. Deferrals lasted for either 30 or 60 minutes.	Chiller power proved very difficult to accurately predict or model. However, the demonstration project was able to conclude that demand response requests are capable of deferring a little more than one-third of a megawatt of load for an hour at a time.
1.4 megawatt WSU diesel generator: Demand response signals were implemented for the control of a 1.4 megawatt diesel generator at WSU's Grimes steam plant. If Avista can control the operation of the diesel generator, the unit's generation might be able to provide energy to the utility, reducing the need to procure energy elsewhere.	Data suggests that demand response mechanisms never engaged the generator. However, this approach continues to possess potential. If 50 hours of generator operation were successfully procured and timed by Avista, it could displace up to 87.5 megawatt hours of the utility's most expensive energy supply per year.
Two 1.1 megawatt WSU gas turbine generators: Demand response control signals were implemented in the two generators, located at WSU's Grimes steam plant. The purpose of the signals was to request, acknowledge, and confirm generation from the two generators.	Based on data, it cannot be confirmed that the gas turbine generators were usefully engaged by the demand response system. Similar to the 1.4 megawatt diesel generator, the potential exists to utilize these two gas turbine generators to provide power to Avista's system. If Avista can modify the operation of the generators for 50 hours each year, it might displace up to 110 megawatt hours of Avista's most expensive electricity.

Final Observations

Avista greatly modernized the Pullman site distribution system and considers its participation in the demonstration project to have been very successful. While the utility encountered immaturity among the smart grid assets that it deployed during the demonstration project, these challenges were mostly overcome. In addition to the projects described above, Avista worked closely with WSU to modernize power electrical engineering laboratory courses—to better prepare the workforce of the future. Two new laboratory classes, on renewable energy and power system protection, respectively, have been added. In addition, a new professional science master degree program is offered, and classroom capabilities for online teaching have been improved.

Benton Public Utility District

Benton PUD serves over 50,000 customers in the Washington cities of Kennewick, Prosser, Finley, and Benton City, as well as surrounding areas of Benton County. The utility district covers 939 square miles and experiences summer peak electrical loads of 430 megawatts and winter peak electrical loads of approximately 340 megawatts. Benton PUD began installation of smart meters prior to joining the demonstration project and completed installation to the entire customer base in 2012.

Demonstration Project Focus

The utility was eager to demonstrate the capabilities and benefits of the advanced meters, as well as energy storage units installed by Benton PUD and neighboring utilities. The units were expected to be responsive to the demonstration project's transactive system.

The utility's projects included the following asset systems:

- DataCatcher™ and AMI advanced meter capabilities
- Energy storage systems.

Benton PUD's Cost Share: $512,500

Projects/Results at a Glance

Project Description	Outcomes
DataCatcher™ and AMI advanced meter capabilities: Benton PUD contracted with Resource Associates International, Inc., to install the company's DataCatcher software, integrated with the utility's system of advanced premises meters. The software acquires event data—such as abnormal temperature and voltage alerts—from the meters. Benton PUD hoped to use that information to anticipate and prevent or rapidly restore outages. Further, the utility sought to use low- and high-voltage reports to correct voltages and reduce instances of customers being supplied electricity outside of accepted voltage ranges.	One of this project's challenges related to data. The ability to analyze five years of data (2010–2014) and draw conclusions was limited due to configuration changes in 2013 that were made by Benton PUD to the network that transmits alerts from the meters to the utility. The reconfiguration effectively rendered 2013 data unusable for analysis and trending of voltage alerts. Other periodic technical anomalies also impacted data quality. Data for 2014 did show the best system reliability numbers in years; however, it can't necessarily be concluded from the limited data that the numbers are attributable to the new technologies. Benton PUD says the DataCatcher software product continues to serve as a valuable tool for providing visibility into real-time electrical system operations and after-the-fact analysis.
Energy storage systems: Benton PUD collaborated with Franklin PUD (Pasco, Wash.) and the City of Richland, Wash., to install battery energy storage units (three 10-kilowatt units and two 1-kilowatt units), all managed via the DataCatcher™ software. Benton PUD sought to demonstrate that these units could charge when a local wind farm produced energy, and then discharge this power during the PUD's peak demand periods, making better use of the wind energy and helping to flatten the utility's demand curve.	The three 10-kilowatt energy storage units were installed and tested at Benton PUD, Franklin PUD and City of Richland sites, and some data was obtained on the units' charging and discharging characteristics. The supplier of the 10-kilowatt units stopped supporting the products in 2013; unfortunately, the batteries could not be operated without the supplier's web-based software. The two 1-kilowatt units were prototypes and proved unreliable for continued operation—thus, the demonstration project could not confirm the 1-kilowatt units' potential.

Final Observations

Benton PUD's two projects proved to be learning experiences. The utility found that distributed energy storage technologies are not yet mature and there is a risk that vendors can go out of business during a project. On a more positive note, Benton PUD continues to gain value from the DataCatcher™ software, and the utility's participation in the demonstration project served to improve awareness within and between Benton PUD's engineering and information technology staff regarding cyber security best practices.

City of Ellensburg

The City of Ellensburg, Wash., is a historic municipality that serves about 10,000 electric and 5,500 gas customers. The community's unique renewable energy park consolidates citizens' efforts to test and use more renewable resources. Residents may buy into the park's renewable projects without having to construct and operate generators themselves.

Demonstration Project Focus

Through its participation in the demonstration project, the city added renewable generation capacity of 153 kilowatts to the renewable energy park. Specifically, the city added more than 40 kilowatts of capacity at an existing solar photovoltaic (PV) generation system, and erected nine wind turbines. The city desired to not only add these additional energy sources, but assess and compare emerging renewable generation technologies to inform future energy decisions. The city's projects were not connected to the demonstration's transactive system.

The solar and wind projects mentioned above were among four projects undertaken at Ellensburg:

- Recloser switch for reliability and outage prevention
- Polycrystalline flat-panel 56-kilowatt PV system (data evaluation only)
- Thin-film solar panel 54-kilowatt array
- Wind turbine systems.

City of Ellensburg's Cost Share: $850,000

Projects/Results at a Glance

Project Description	Outcomes
Recloser switch for reliability and outage prevention: The city purchased and installed a remote recloser switch at the interface between all the renewable generators and the city distribution system. During occasional overgeneration events on the Bonneville Power Administration (BPA) system, the switch could be remotely opened using the site's supervisory control and data acquisition (SCADA) system, and quickly disconnect the renewable generators at the park, helping to improve grid reliability. As part of this project, fiber optic cable was installed to tie park communications to the city's electricity distribution operations center.	The switch operation was successfully tested by the city via the SCADA system in December 2012. The project was not successful in its efforts to connect the operation of the switch to mitigation of overgeneration events. There was no signal or program available to the city for that purpose.
Polycrystalline flat-panel 56-kilowatt PV system: This system existed prior to the demonstration project, but the city offered, for evaluation purposes, the system's data. The objective was to identify the value of the system in displacing energy otherwise supplied by the BPA.	Data collection began in August 2012 and continued through August 2014. The maximum hourly generation from the PV system was about 50 kilowatts, somewhat less than the 56-kilowatt nameplate capacity. The sum value of the annual generated energy (approximately 80 megawatt hours) was found to be approximately $2,300-2,500—based on the value of the energy the city would otherwise need to purchase, and on BPA load-shaping rates. Further analysis determined the PV system provides a negligible influence on peak electricity demand and BPA peak demand charges (a fee that helps BPA ensure that power is available to utilities during high electricity demand periods). The array continues to operate and produce significant, predictable quantities of energy.
Thin-film solar panel 54-kilowatt array: During the demonstration project, the city added 40.5 kilowatts of nameplate generation capacity to its existing 13.5 kilowatt thin-film PV power generation. As with the other renewable generation at this site, the city installed this resource to reduce demand from its energy supplier.	Data collection began in July 2012 and continued through August 2014. The unit cost of the energy produced by the newly-installed portion of the system was found to be 28 cents per kilowatt hour, which is expensive compared to wholesale, or even retail, electricity in the Northwest. Looking at this array as a whole, the value of the total displaced supply (power that does not need to be purchased from BPA—in the case of this array, approximately 80 megawatt hours per year) was on the order of $2,300-$2,400 annually. As with the 56-kilowatt system, this one also had little impact on BPA peak demand charges. The array continues to operate and produce significant, predictable quantities of energy.

Wind turbine systems: The city, hoping to supplement its power and energy requirements, and effectively reduce its demand from its supplier, installed and tested five residential-class wind turbine systems and four larger commercial-class wind turbine systems.	The wind generators produced relatively small amounts of energy for the city, and, in fact, a number of reliability issues surfaced. Two of the residential wind generators and two of the commercial systems experienced operational failures. In the case of another of the systems, its tower toppled in April 2013, after which the city, citing safety concerns, halted testing and committed to quickly remove all wind towers. Five of the systems produced electricity, but others generated little. In all cases, impacts on demand and BPA demand charges were negligible.

Final Observations

The city experienced a number of challenges in executing this project, including the fledgling nature of the small renewables industry (Ellensburg spent almost two years just finding products to use), great differences in reliability and efficiency of the various systems, and difficulty in finding qualified maintenance support. The city did receive some benefit from the public visibility of the renewable technologies at its renewable energy park site, but these benefits are indirectly realized, and there was no attempt to attribute a value.

Flathead Electric Cooperative

Flathead Electric Cooperative, Inc., is the largest electric cooperative in Montana and serves approximately 49,000 members. The cooperative oversees 4,500 miles of overhead and underground power lines, and serves the entire Flathead Valley and the community of Libby, along with several hundred members along the Montana-Wyoming border.

Demonstration Project Focus

The cooperative worked with the demonstration project to define two demonstration sites within its service territory at the communities of Libby and Marion/Kila. Two sites were used because the cooperative wished to learn about technologies as they might be applied in both urban (Libby) and rural (Marion/Kila) locations.

Through the demonstration, the cooperative sought to finish deployment of its automated meter-reading system and perform other upgrades, develop tools to reduce members' peak period power costs, further investigate demand response approaches (which allow consumers and smart devices to know when power costs are high, and alter use accordingly) and generally modernize its power grid.

Flathead Electric designed and branded its projects under the public-facing name, "Peak Time™." The cooperative hired a demand response coordinator, a new staff position, to manage the Peak Time™ program and to recruit, educate, and interact with member participants. The program was communicated to members via newspapers, newsletters, radio, the cooperative's website, mailings, bill inserts, and community meetings. The cooperative ultimately was able to recruit 290 customers in Libby and 49 in the Marion/Kila area to participate in Peak Time™ activities.

Flathead Electric's demonstration projects were:

- Advanced metering infrastructure (AMI) for outage recovery
- In-home displays
- Demand response units (DRUs)
- Demand response appliances

Flathead Electric Cooperative, Inc.'s Cost Share: $2.3 million

Projects/Results at a Glance

Project Description	Outcomes
AMI for outage recovery: The cooperative installed advanced residential interval power metering at member premises served by three substations. A goal was improvement in meter-reading frequency and billing accuracy, but the meters also enabled the cooperative to view complete sets of hourly interval data for each substation, as well as real-time outage information. This could lead to more efficient outage troubleshooting and restoration, and improvements in reliability indices.	Reliability metrics for affected feeders, from September 2011 to October 16, 2013, were provided by the cooperative. Unfortunately, the data that was provided did not facilitate the desired comparison.

In-home displays: In-home display units were provided to and installed by participants. The devices were simply plugged into a wall socket, and communicated via the power-line-carrier communication system of the advanced metering at each premises. The devices emitted an audible alarm and displayed the message "Peak Time" on their screens during peak power use periods. Members, upon receiving the alarm, were expected to manually curtail their electricity use. These Peak Time events could be called by the cooperative or advised by the demonstration project's transactive system.	Over the life of the in-home display project, the test population in Libby ranged from 65 to 90 participants, and in Marion/Kila, 8 to 12 participants. In Libby, a marginally significant load reduction was reported during Peak Time events. The reduction was estimated to be at least 60 watts per premise, and perhaps up to 220 watts. The power use reductions typically extended even beyond the length of the Peak Time events. Carried out over a year, the Peak Time events in Libby might reduce yearly BPA demand charges (a fee that helps BPA ensure that power is available to utilities during high electricity demand periods) to Flathead Electric by $3,500. In Marion/Kila, no significant reduction in load was identified. The in-home display testing was curtailed after one year—the cooperative determined the audible alarms were annoying to participants. Other issues encountered by the cooperative included the challenge of effectively configuring the in-home displays to the demonstration project's transactive system
DRUs: Cooperative members who possessed advanced interval meters were candidates to participate in this project, which involved installation of DRUs to control residential electric water heaters as a means of managing the overall power load. The devices communicated via the existing power-line-carrier system; a command could be sent to curtail the water heaters' electric load, and the water heaters would be temporarily turned off. The events could be called by the cooperative or advised by the demonstration project's transactive system. The benefit of the DRU technology versus the cost of providing it was to be evaluated by comparing incremental costs and benefits for the premises that accept DRUs against those that have only AMI.	Libby test population counts for the DRUs ranged from 85 to 92 participants over three years (August 2011-14); Marion/Kila ranged from 15 to 21 between February 2012 and August 2014. In Libby, an electricity load reduction was consistently observed during events at homes that had DRUs, and analysis suggests a reduction of at least 200 watts per residence. Similar results were observed in Marion/Kila, though reductions were about half as much. In both locations, as might be expected, power use increased after the end of the events. It's estimated the Libby reductions would translate to modest savings (under $20 per year) in terms of power the utility would otherwise need to purchase; BPA demand charges might be reduced by approximately $1,200 per year.
Demand response appliances: The cooperative selected a suite of General Electric "communicating" appliances (washer/dryer sets and dishwasher), a home energy gateway unit, a 240-volt water heater switch, and an energy display, and installed them at qualifying members' homes. Qualifying members were home owners who possessed electric water heaters, a home computer, and internet connectivity, and who agreed to pay a deeply subsidized rate of $800 for the entire suite of devices. Both Peak Time demand response and the grid demo's transactive system were engaged in testing to understand how the response of the appliances to events could affect electricity load.	On an average monthly basis, the number of premises participating in the appliance test ranged from 67 to 101 at Libby (August 2012-August 2014); and 12 to 17 participants at Marion/Kila (January 2012-August 2014). Nineteen Peak Time events were conducted, some overlapping with the demo's transactive events. In Libby, the appliance suite was estimated to have reduced consumption from 100 to 180 watts per premise during an event; in Marion/Kila, the reduction estimate ranged from approximately 170 watts per premise up to 260 watts. Data was inconclusive as to whether power consumption increased following events. Analysis confirmed an energy savings in Libby of 600-1,000 kilowatt hours per year. The value of the energy and of its impact on peak demand was small.

Final Observations

A key lesson learned for the cooperative was that the communication technologies used in projects were not easily integrated. Because "smart" technologies are advancing so rapidly, industry trends and these products change faster than a utility can react. Product models and features changed between the times the cooperative selected and implemented the technologies.

Prior to conclusion of Flathead Electric's Peak Time™ projects, the cooperative completed a survey among the customer participants. Virtually all—97 percent—who responded to the survey indicated they would participate in a similar program again and would recommend participation to other members.

Idaho Falls Power

Idaho Falls Power is a municipal electric utility that serves 22,400 residential and 3,700 commercial customers in Idaho Falls, Idaho. In 2013, 42 percent of its retail power was supplied to residential customers, 39 percent to commercial, and 13 percent to industrial customers. The city also operates 37 miles of transmission lines, 410 miles of distribution lines and 53.5 megawatts of hydroelectric, wind, and solar generation.

Demonstration Project Focus

Idaho Falls Power elected to demonstrate the greatest variety of asset systems of any utility participant in the grid demonstration.

Idaho Falls Power's demonstration projects were:

- Voltage management
- Power factor control
- Distribution automation
- Water heater control
- Plug-in hybrid electric vehicle (PHEV), solar, and battery storage
- Thermostat control
- In-home displays (IHDs).

Idaho Falls Power's Cost Share: $3.5 million

Projects/Results at a Glance

Project Description	Outcomes
Voltage management: The utility installed a load tap change controller at a substation to manage the feeder's voltage. One objective was conservation voltage regulation. The city expected to observe a reduction in feeder energy consumption after the system was installed and while applying a lower, managed distribution voltage to the feeder. The project also used the technology to evaluate wear and tear on distribution equipment, and monitored high- and low-voltage alarms to understand whether distribution voltage management degraded or improved the quality of delivered voltages. The voltage management system was configured to respond to the demonstration project's transactive system.	The voltage management system was installed as of June 29, 2012. The transactive function began advising the system to engage in March 2013, but that did not happen. Based on analysis of voltage data, it appears the voltage control system was first exercised for an approximately six-month period beginning in February 2014. Sum energy purchases avoided during these six months were worth approximately $2,700. Extrapolated to one year, the total annual displaced energy might be worth about $5,400. As for BPA demand charges (a fee that helps BPA ensure that power is available to utilities during high electricity demand periods), if voltage management was exercised all year, the utility might have reduced its demand charges by at least $6,000 annually. This number presumes peak hours would be correctly identified through the year. The voltage management system proved effective toward improving the quality of delivered voltage for the premises on the feeder; findings were inconclusive on wear and tear of distribution equipment.
Power factor control: Idaho Falls Power automated the control of switched capacitor banks at two large breweries. The purposes were to reduce system losses and to improve feeder power factor (a measure of the efficiency of the power being used). Local controllers at the industrial premises supervised the switched capacitor banks to make sure that power factors remained within acceptable parameters.	Uncertainty around data quality made it difficult to assess this activity. If the data indeed is accurate, then the installation of switched capacitors reduced average distribution current on two feeders by 12 percent and 4 percent, respectively. Line losses are inferred to have decreased. Such results would serve to optimize electricity resources and might defer the need to build electricity supply infrastructure in the future.
Distribution automation: The utility, using its remotely controlled switch operators, its advanced metering infrastructure (AMI) system, and fault indicators, installed a fault detection, isolation, and restoration (FDIR) system. The FDIR is designed to quickly detect fault locations and isolate the faulted parts of two circuits that are supplied by one of the utility's substations, thus reducing the duration of service outages.	The system was installed by November 9, 2012. Idaho Falls Power calculated and submitted yearly reliability indices and metrics for two feeders for years from 2010 through the end of the demonstration project. The demonstration project will not report any conclusions regarding reliability based on the limited history of metrics that have been collected. However, no outages had occurred during the last nine months of the project, which is very promising, provided this trend endures.

Water heater control: The utility installed 218 load control modules to curtail residential electric tank water heaters. These units were controllable by Idaho Falls Power.	The system was installed as of December 21, 2012. Test events were conducted during 2013 and into February 2014, and the system was made automatically responsive to the demonstration project's transactive system briefly from late 2013 until early 2014. Idaho Falls Power chose to remove all the modules in early 2014 due to a small number of catastrophic device failures. There might have been reductions in power use during curtailment of hot water heaters, but the demonstration project cannot confidently confirm, from available data, that any reduction in power was achieved. Idaho Falls Power believes reductions were achieved and that the technology has the potential to deliver significant savings.
PHEV, solar, and battery storage: The utility installed a 10-kilowatt/40-kilowatt-hour battery storage system, which was to be charged and discharged based on the demonstration project's transactive control incentive signal. The battery system was located near four PHEV charging stations and a 1.73 kilowatt photovoltaic solar panel system at the utility's headquarters.	The system was installed by January 17, 2013. Data was never made available from the battery storage system. The battery's vendor encountered financial difficulties and stopped supporting the device soon after it had been installed. The utility was left with no way to control the battery storage module.
Thermostat control: Idaho Falls Power installed 42 programmable, controllable thermostats at participant premises. This project included establishment of a transactive node for connection to the transactive system. Participating residents programmed their preferred temperature set points. The utility was able to temporarily increase or decrease the test group's set points during events.	The thermostats were installed by December 21, 2012. The transactive system began advising events in February 2013. Data from participant premises were compared against 29 premises that did not receive the thermostats. The devices' total impact on energy supply and energy-supply costs was negligible. However, based on the way the utility operated the thermostats for part of a year, BPA demand charges were reduced on the order of $400-500. Had the system been exercised similarly throughout the year, the reduction might have been in the $600-700 range. Idaho Falls Power received very little negative feedback on the thermostats. In fact, a survey found that three-fourths of participants would enroll in the program again.
IHDs: The utility installed 860 IHDs in participant premises. The utility expected the devices would prompt energy conservation via customer behavioral changes. Customers could view a wide range of energy info, such as the current month's electricity consumption, the previous day's usage, demand-response events, etc.	The system was declared installed and tested February 22, 2013. The average monthly energy consumption of those premises with IHDs and advanced metering increased slightly, whereas for premises with advanced metering only, consumption decreased somewhat—outcomes that make it difficult to assess the impact of IHDs. In a survey, nearly 40 percent of those with devices said they looked at the displays daily. Most participants said they didn't experience a change in power usage during the program, but 35 percent indicated slightly lower consumption.

Final Observations

Idaho Falls Power found that interoperability is still very new in the smart grid industry, despite some vendors' claims. Integration of systems proved difficult, time consuming and expensive.

The utility's participant survey toward the end of the demonstration project found that a large number (65 percent) of customers participated in the project because they wanted to reduce their power costs. Additional reasons for participation included the environmental and community benefits from decreased energy use, and the opportunity to use new technologies. In terms of the project's impact on daily life, respondents indicated that convenience of participation was an important factor to them, as was minimal lifestyle interference.

Lower Valley Energy

Lower Valley Energy is a rural electric cooperative located in Northwest Wyoming and Eastern Idaho. The service territory is expansive, featuring towns, very remote rural substations, and even a mountain ski resort. Terrain is mountainous. The cooperative serves 27,000 electric customers.

Demonstration Project Focus

The utility selected substations at the following Wyoming sites for demonstration tests: East Jackson, Afton, and Bondurant (Hoback substation).

Lower Valley Energy's demonstration projects were:

- Advanced metering infrastructure (AMI) and in-home energy displays (IHDs)
- DRUs—demand response units
- DRUs and AMI for reliability
- Adaptive voltage regulation (East Jackson site)
- 600 kilovolt amperes reactive (kVAr) static VAr compensator (SVC) - (Bondurant/Hoback site)
- Battery storage system (Bondurant/Hoback site)
- 20-kilowatt solar photovoltaic system (Bondurant/ Hoback site)
- Four 2.5-kilowatt wind turbines (Bondurant/Hoback site).

The East Jackson and Afton sites are moderately populated. These two sites were primarily used to test member interaction with advanced metering and IHDs. In contrast, Bondurant is rural and is at the remote end of a long distribution line. While some premises on this feeder also received advanced metering and IHDs, the cooperative hoped to strengthen the electrical supply to the Hoback substation, which serves Bondurant, and to defer upgrades using a diverse set of SVCs, renewable energy resources, and battery energy storage.

Lower Valley Energy's Cost Share: $1.2 million

Projects/Results at a Glance

Project Description	Outcomes
AMI and IHDs: The cooperative targeted installation of 500 IHDs, primarily at Afton. Advanced meters also were installed and used to communicate with and monitor the performance of the system of premises having IHDs. Participants were able to view their real-time power demand and the current month's energy consumption. The cooperative wished to engage its members via the IHDs to reduce needs for future BPA TIER-2 power, which is the more expensive power that must be used after the utility's allocation of TIER-1 power has been consumed. The cooperative opted not to use the demonstration project's transactive system at this site.	IHDs were installed as of March 2012. Following data analysis, it was not possible to confidently attribute any reduction in power consumption to the installation of IHDs, but the demonstration project found compelling evidence that the installation of advanced metering reduced premises power consumption. One hypothesis is that an actual power reduction follows the installation of advanced metering because the information and education received by the affected members induce them to truly conserve energy. Another hypothesis is that the newer meters are calibrated differently from the older meters, and in the cooperative members' favor.
DRUs: The cooperative installed 530 DRUs at premises controlling 566 water heaters at Afton. The DRU system and curtailment events were primarily managed from the Afton control room; only a few of the devices were made automatically responsive to the demonstration project's transactive system. The objective of the DRUs test was reduction of monthly system peak and corresponding demand charges (a fee that helps BPA ensure that power is available to utilities during high electricity demand periods).	System performance proved inconsistent; the reason could not be fully determined. Based on all the curtailment events the cooperative had reported in which they controlled the DRUs, the demonstration project concluded that, on average, each DRU had conserved just over 100 watts during the events. Looking at the cumulative impacts over time, the demonstration project identified several months of peak performance, during which each DRU curtailed almost 500 watts.
DRUs and AMI for reliability: The cooperative expected to improve the reliability indices at all its feeders by employing advanced metering and other smart grid assets. The metering provided better overall visibility of the cooperative's distribution system. Additionally, autonomous tripping of water heater DRUs during under-frequency and under-voltage events can shed load and perhaps avoid some outages. The water heater DRUs also may be commanded to remain off during cold-load pickups, thus helping the cooperative recover from outages.	System was installed by early 2011. The cooperative supplied to the demonstration project yearly data for all three major reliability indices, from which analysis was conducted. The demonstration project could not identify any evidence a global improvement in system reliability had occurred. Of course, it is possible that an impact occurred and was overwhelmed by other natural and induced influences. It also is important to note that installation of new smart assets is just one of many factors that may affect reliability indices.

Adaptive voltage regulation: With the help of voltage data from its advanced metering infrastructure system, Lower Valley sought to use adaptive voltage control and conservation voltage reduction (CVR) to reduce its peak demand. The voltage was reduced periodically by about two percent on four East Jackson feeders, affecting a little more than 2,300 premises.	A solid reduction in feeder distribution power was observed for the up to 3-hour-long voltage reduction events on the feeders, but the impact diminished after a strong showing in 2012. Additionally, the project found evidence that consumption at residential premises actually increased during these events. Test groups would need to be better controlled for the potentially confounding impacts from DRUs and repeated to confirm the contrary result at the premises level.
600 kVAr static VAr compensator (SVC): Lower Valley Energy procured and installed a 600 kVAr SVC. With the SVC engaged, the cooperative expected to decrease about 300 kVAr for power factor and voltage support. By improving power factor, the cooperative hoped to reduce line losses of electricity and to improve voltage management on the feeder.	The SVC was installed by mid-2012. From its analysis, the demonstration project concludes that power factors improved over time, and the reduction of distribution line losses when the SVC was active was approximately 30 percent prior to April 2013 and 13 percent thereafter.
Battery storage system: Lower Valley Energy installed a battery storage system, seeking to reduce its peak demand and distribution line losses, and defer distribution capacity investments on the Hoback substation's distribution supply. The battery system was controlled and monitored via a remote terminal unit and the existing supervisory control and data acquisition (SCADA) system at the substation. When a control signal was received by the system, it either supplied energy to or stored energy from the feeder line.	The system was exercised regularly after March 2014, so the project limited its analysis to the months of March-July 2014. If the system were to be operated for a year in the manner it was for four months, the demonstration project predicts the utility would lose from $50-90 through the arbitrage of energy supply. Regarding BPA demand charges, and presuming the costs from the four months with data are similar to those of the remaining eight, the demonstration project estimates the yearly impact of battery operations on demand charge reductions to be from $80-160 per year.
Solar PV system: Lower Valley Energy installed a 20-kilowatt solar PV generator system at its Hoback substation. The cooperative hoped to displace energy supply and learn the cost-benefit of investing in PV systems.	The generator was installed and useful by the end of October 2012. The demonstration project finds that based on this system's operation, its annual generation should be approximately 29 megawatt hours. One of the benefits of this system is its ability to displace energy that would otherwise need to be supplied from BPA. The demonstration project reports that the value of annual displaced supply energy ranges from $838 to $878.
Wind turbines: Lower Valley Energy sought to displace energy supply and better understand the costs and benefits of investing in wind turbines. The cooperative installed four 2.5-kilowatt wind generators at the Hoback substation.	The cooperative was not able to achieve acceptable performance from the turbines. The manufacturer is no longer in business. No significant generation can be reported, and it appears no monetary benefits were obtained.

Final Observations

Lower Valley Energy found that more money should have been budgeted for project reporting expenses and integration. Integration of existing systems with new devices proved particularly challenging. Generally, the cooperative's vendors had a hard time meeting production time deliveries, and some equipment had been damaged during shipment, resulting in unexpected delays.

City of Milton-Freewater

The City of Milton-Freewater is a municipality in northeast Oregon that serves about 7,000 residents. It is proud to be one of the oldest municipal electric utilities in Oregon and offers power rates among the lowest in the Pacific Northwest. The city's electric utility is a pioneer in energy conservation and demand responsive programs. In fact, the community's Radio Energy Management System direct demand response program began in 1986.

Demonstration Project Focus

The city offered its entire municipality to be used as a demonstration project site.

Milton-Freewater's demonstration projects were:

- Demand response units (DRUs) on water heaters and space conditioning equipment
- Dynamic distribution voltage management
- Voltage-responsive, grid-friendly DRUs
- (Static) conservation voltage reduction (CVR).

The first three of these projects were made responsive to the demonstration's transactive system.

City of Milton-Freewater's Cost Share: $2.189 million

Projects/Results at a Glance

Project Description	Outcomes
Demand response units: The city purchased 800 DRUs and installed them at residences and a few commercial buildings. These devices responded to transactive signals and controlled either conventional 240-volt alternating current electric tank water heaters or space conditioning units, deferring energy consumption as necessary. In addition to the demonstration project's transactive system, the city also could and did initiate its own transactive events. The city's main purpose in installing the DRUs was to reduce BPA demand charges (a fee that helps BPA ensure that power is available to utilities during high electricity demand periods).	A vendor software error was found to have prevented many of the demonstration project's transactive system events from having been acted upon prior to about July 2014. For this and other reasons, early performance of the DRU system was poor, but improved over time and became consistently better. The demonstration project calculated that, on average, each DRU reduced its premises' load by about 100 watts during all the DRU curtailment events; toward the end of the project, the DRUs were consistently curtailing 270 watts at each DRU location. Per demand charges, actual curtailment events and advised transactive events largely failed to identify the monthly hours on which demand charges were, in fact, incurred.
Dynamic distribution voltage management: The city configured nine of its distribution feeders to reduce voltages by 4.5 percent during transactive events when curtailment was advised. These events typically lasted several hours. The voltage was returned to normal at the conclusion of each event. The main impetus for short-term power reduction for the city was avoidance of BPA demand charge increases.	Project analysts had expected to observe a reduction in consumption for distribution feeders and at premises, as is normally the case for static CVR that is applied over long time periods. This expectation could not be confirmed. Quite the opposite appeared to be the case for short, dynamic voltage reductions on the feeders. The city contends that it easily observes reductions in feeder loads soon after voltages have been reduced. Researchers hope to revisit this issue and learn why results were contradictory.
Voltage-responsive, grid-friendly DRUs: The city allowed about 100 of their new water heater DRUs to be made responsive to voltage reduction. The city worked with the vendor to configure the DRUs to sense and then respond (fully curtail power use) to the 4.5 percent voltage reductions that already were occurring on Feeders 7–10 as part of the city's dynamic voltage-reduction system. Curtailment of the voltage-responsive water heaters could help the city avoid demand charges from BPA if the curtailments were made to reliably coincide with peak utility hours each month.	The voltage-responsive water heaters were reliably and consistently curtailed by the reduction in distribution voltage events—leading to reductions in electricity consumption (approximately 170 watts each). However, a strong rebound effect occurred in the hours immediately following voltage reduction—the water heaters increased consumption. Regarding the BPA demand charge, it's possible that if the city operated the voltage-responsive water heaters as demonstrated, and if the water heaters could be engaged during peak hours each month, the city might save at least $1,360 annually.
(Static) conservation voltage reduction: Every other week, city staff reduced the distribution voltages on four feeders by one transformer tap—about 1.5 percent. The change in voltage was performed at the same time each week over the project term. The city wished to investigate CVR as a means to conserve electricity.	Most, but not all, of the monthly results indicated a reduction in power consumption of up to 26 kilowatts for the four feeders.

Final Observations

All four project technologies (asset systems) that were pursued by the city during the demonstration project remain installed and useful. Milton-Freewater continues to work toward a more automated system that will help shave its monthly peak demand. Per information technology needs, the city relies on consultants to help with its computer systems and associated security issues. The city feels it now possesses a much clearer understanding of cyber security than it did prior to the demonstration project.

Among lessons learned, the city found it significantly underestimated the staff time that was required for project implementation and necessary accounting and reporting tasks.

NorthWestern Energy

NorthWestern Energy serves more than 400,000 electric customers in a service territory that covers much of Montana, South Dakota, and Nebraska. The territory's 123,000 square miles include 27,600 miles of electric transmission and distribution lines.

Demonstration Project Focus

The utility selected two field sites. The first involved eight distribution circuits from three of the seven utility substations in Helena, Mont. The relatively urban site engaged approximately 200 residences and one state government building. The second site, near Philipsburg, Mont., is more rural and included only one substation and circuit. The circuit, however, is expansive, and extends 40 miles from the substation, consisting of approximately 240 line miles.

In the demonstration project, NorthWestern Energy's participation focused on two distinct sets of activities that address utility and customer aspects. The utility-side activities included:

- Integrated volt/VAr control (IVVC) or volt/VAr integration and optimization (VVO)
- Distribution automation, also known as fault detection, isolation, and restoration (FDIR).

On the customer side, the utility provided a set of residential and commercial customers the means to control their electricity usage, respond to time-of-use pricing, and participate in demand response load control.

NorthWestern Energy's Cost Share: $2.1 million

Projects/Results at a Glance

Project Description	Outcomes
IVVC-Helena: Automated voltage regulator controls, automated capacitor banks, distribution voltage sensors, and distribution system software were used to automate voltage and reactive power control (IVVC) on several feeders. This affected 6,100 customers on circuits supplied by two substations. The utility's objective was to demonstrate that voltage and reactive power control automation produces benefits without customer complaints, and to measure its benefits.	NorthWestern Energy reported that when the utility first exercised the Helena IVVC system in December 2013, there was an average change of 1.21 percent in the voltage. Demonstration project models determined that on one of the circuits, power consumption was approximately 16 kilowatts less when the IVVC system was engaged, or almost one percent of the average power on the circuit during 2014, and about one-half percent of the peak power. Demonstration project findings for the other circuits were inconclusive.
IVVC-Philipsburg/Georgetown: Automated voltage regulator controls, automated capacitor banks, distribution voltage sensors, and distribution system software were used for voltage and reactive power control in NorthWestern Energy's rural service territory of Philipsburg/Georgetown. The utility's objective was to demonstrate that voltage and reactive power control automation produces benefits without customer complaints, and to measure its benefits.	The system was installed and active by February 2014. The demonstration project evaluated operation for the period of March-July 2014. One of the challenges of evaluating the system's impact was the Flint Creek hydroelectric generation site, the local power source. The plant's intermittent starting and stopping of generation influenced data, and had to be filtered out to arrive at more meaningful conclusions. Even with that challenge, analysts were able to calculate that when the voltage levels are reduced, the circuit used approximately 27 kilowatts less power, on average, which reduces Philipsburg's average load by about one percent.

FDIR: NorthWestern Energy installed FDIR technology in Helena and Philipsburg that automatically reconfigures circuits after outages to restore service to as many customers as possible. The utility wanted to quantify the benefits they would realize from its use, including improvement of service reliability. The four Helena circuits with FDIR affected 4,800 customers.	The demonstration project examined the utility's yearly distribution restoration costs and two reliability indices. Based on the data received, some of which was incomplete, there were no clear-cut indications or trends suggesting restoration costs were decreasing or reliability was increasing. However, there are other, real-life factors that might point to improved response to outages. In one case, a tree fell on a line; the FDIR transferred load within 51 seconds, significantly reducing outage time for the premises on that particular circuit versus other customers. In this example, NorthWestern Energy attributes the avoidance of 148,000 outage minutes to the FDIR system. A second incident witnessed similar results, with nearly 800 customers being restored to power within 30 seconds after an outage.
Residential/commercial demand response: NorthWestern Energy supplied various tools to residential customers, equipping them to learn about and better manage their electricity consumption. Approximately 200 residential customers received smart meters, energy information portals, in-home display units, web-based services and a programmable thermostat. The utility sought to evaluate device performance and use. The utility also explored variable pricing and customer response to price signals. All customers who accepted the tool suite were placed on a time-of-use pricing schedule. They could reduce their energy bills if they modified the times that they consumed electricity according to the schedule. To boost interest, NorthWestern conducted quarterly contests, rewarding participants who had conserved the most energy in the quarter compared with their consumption in that quarter the prior year. In another aspect of the project, the utility outfitted one state-owned building with lighting and dimming controls, as well as heating, air conditioning and ventilation controls.	The residential program began with 195 customers and ended with 190, with some flux of customers entering and leaving the program over its duration. A lack of historical and control group data made it difficult for demonstration project analysts to pinpoint reductions in average premises loads on circuits that had received the demand response equipment, or any impacts from time-of-use price differences. However, the utility reported that residential customers had indeed lowered their power bills by shifting electric load to times having lower electricity prices. The highest average monthly savings per participating customer was $8.88. The maximum monthly bill credit earned by a customer was $31.15.

Final Observations

Looking to the future, NorthWestern Energy continues to examine the actual costs and cost savings to the smart grid activities it conducted. The concept of smart grid and transactive control is relatively new to the utility industry and to NorthWestern Energy as well. Therefore, the utility was pleased to take part in the demonstration project, and to collaborate with and learn from the diverse set of project participants. The demonstration touched most every department at NorthWestern, from distribution engineering and operations to safety, regulatory affairs, customer care and corporate communications. Many personnel from many disciplines worked to complete the design, installation, and testing of the project.

There were mixed results in relationships with vendors who supplied technologies to NorthWestern Energy's projects. Several vendors—typically those with a proven track record and solid financial base—remained very committed to the project. Conversely, the utility faced schedule and cost pressures when one manufacturer was bought out by another prior to producing an agreed-upon software package. Additionally, another vendor downsized staff numbers to stay in business, which meant decreased technical support time and constant changes in project management and sales.

Peninsula Light Company

Peninsula Light Co.
a mutual corporation - since 1925
The power to be...

Peninsula Light Company is the second-largest rural electric cooperative in Washington state, serving more than 65,000 people. Roughly 88 percent of its members are residential—73 percent of the electric load. The cooperative's service territory includes peninsulas and islands that surround the community of Gig Harbor.

Demonstration Project Focus

The cooperative concentrated its project resources on Fox Island, served from the Gig Harbor Peninsula by only two distribution circuits. With load growth preceding the demonstration project's start, either of these circuits' capacity limits could be exceeded if the other circuit were to fail.

Peninsula Light Company's demonstration projects were:

- Installation/evaluation of demand-side management using load control modules (LCMs)
- Conservation Voltage Reduction (CVR) with end-of-line monitoring
- Dynamic distribution automation, including fault detection, isolation and restoration (FDIR).

The company's engagement of LCMs for the curtailment of electric tank water heater load on Fox Island went beyond a test. The modules were engaged soon after they became deployed to help the company manage the failure of one of the lines that supplied the island from the mainland.

Peninsula Light Company's Cost Share: $1.2 million

Projects/Results at a Glance

Project Description	Outcomes
Load reduction with LCMs: The cooperative installed and engaged approximately 500 residential LCMs. These devices were to disconnect hot water heaters and other household resistive loads in order to achieve demand reduction. They were controlled using the utility's existing power line carrier network.	The cooperative, though challenged, eventually was able to align control of the LCM system with the demonstration project's transactive system. As a result, in a majority of cases, the LCMs were engaged when advice was received from the transactive system. Another challenge pertained to the power line carrier network, which proved problematic, limiting measurements and data. The cooperative began allowing the LCMs to be curtailed gradually, beginning June 2013. There were 217 curtailments called for by the LCMs during the project. Analysis of data from premises and a substation showed small reductions in power use, but the demonstration project's confidence in those results is low, and the project cannot confirm load reduction impact. However, as noted earlier, the modules helped the company manage load during failure of one of the island's electricity supply lines.
CVR with end-of-line monitoring: Peninsula Light procured and installed two voltage regulator banks and controlled six existing capacitor banks to facilitate CVR on Fox Island. The system was intended to reduce electricity demand, especially at times that the system was heavily loaded.	Peninsula Light encountered delays in implementation of this asset because the existing infrastructure could not provide the necessary rapid and accurate voltage measurements. The system was installed as of January 2014. The demonstration project found no evidence that system behaviors were significantly altered at the times that the system was reported to have differently managed distribution voltages.
Dynamic distribution automation, including FDIR: The cooperative applied FDIR with supervisory control and data acquisition (SCADA)-controlled distribution switches to monitor and more quickly recover from distribution system faults on Fox Island. The SCADA system maintained a real-time state of the connected network with load flow and circuit ratings, and calculated an optimal network configuration in the event of a faulted section of network. The objective was to reduce the customer outage durations and perform cold-load pickup by quickly restoring as much healthy network as practical, without exceeding circuit capacity.	The system was installed in September 2012. The cooperative was able to provide little historic reliability data for comparison purposes, which limited analysis. Based on findings from the analysis, the demonstration project cannot conclude that customer outage durations improved with the installation of FDIR, or that outage response times significantly improved. Even so, there appeared to be some positive indicators in the numbers from March 2014 until the end of the demonstration project's data collection period in September 2014.

Final Observations

There were many challenges in the implementation of the Peninsula Light Company's demonstration tests. The challenges primarily fell into two camps: technology and integration. An additional factor that added to the challenge was changes to the cooperative's engineering staff after the tests had been defined and equipment and software had been selected and purchased. The collective shortcomings of the hardware, software and existing system capabilities that emerged as the project progressed would have been a challenge even without changes in utility personnel.

While customer outage duration numbers may not have shown reliability and outage response improvements, there was an anecdotal example of FDIR-related benefit—which could portend a positive outcome for the future. When a large tree fell on a major feeder and disrupted power to more than 1,000 customers, the system quickly identified the location of the problem, enabling its isolation and restoration of the rest of the circuit. The vast majority of affected customers were back on line within 30 minutes.

Portland General Electric

Portland General Electric (PGE) is an investor-owned utility that serves much of Portland, Ore., and areas south. It is Oregon's largest utility, with 843,000 customers, of which 100,000 are in the commercial sector. The utility owns a diverse mix of generation resources including thermal, natural gas, hydropower, and renewable.

Demonstration Project Focus

Activities were centered in Salem, Ore., and constituted what was known as the Salem Smart Power Project. PGE tested and demonstrated a number of smart grid technologies. The most ambitious aspect of the project was the development of a large battery energy storage system at PGE's Salem Smart Power Center (SSPC).

The utility's five projects were:

- Residential demand response
- Commercial demand response
- Commercial distributed standby generation
- Battery storage in a high-reliability zone
- Distribution switching and residential/commercial microgrid.

Portland General Electric's Cost Share: $12.8 million

Projects/Results at a Glance

Project Description	Outcomes
Residential demand response*: PGE sought to test customer acceptance of energy management devices such as water heater timers, air conditioner controls, energy management displays, etc., and measure resulting power system load shifts or reductions. The objective of the utility's residential demand response technology demonstration was to test customer acceptance of energy management devices and to measure the degree to which load might be reduced or shifted.	This activity had actually started in advance of the demonstration project. After considerable recruitment efforts, PGE was able to identify 20 suitable customers for this program, but only two premises became observable to the project through data collection. Changes designed to safely accommodate testing of the utility's battery system limited the observability of the premises data. The residential program was terminated in October 2013 following a technology malfunction at a residence. No useful data was obtained regarding performance of residential demand response devices.
Commercial demand response*: PGE offered demand response technologies, including building management systems, control relays and space conditioners, to qualifying businesses, and these assets were made automatically responsive to the utility's transactive system. The objective was to test customer acceptance of the technologies and measure any resulting load reduction and shifting. The utility used its commercial demand response system to engage commercial loads with customers within the demonstration feeder, thus reducing load when a transactive event was called. Commercial customers could opt not to participate in an event.	Eight commercial customers participated. The system was declared installed and operational by the end of January 2013. Three test events were conducted in January, July and December of 2013. While PGE anticipated a reduction in power use during events, the demonstration project, at least based on results from the three tests, could not confirm a curtailment benefit. The system would need to be engaged more frequently to observe and confidently claim such an outcome.
Commercial distributed generation: When called upon via PGE's Distributed Standby Generation controls, power generation was to be initiated from distributed, customer-owned stationary diesel reciprocating engines at the Oregon Military Department, Armed Forces Reserve Center and Oregon Data Center. The utility pioneered engagement of such distributed generation resources via its GenOnSys control system in Portland. The arrangement allows the utility to tap additional electricity sources to respond to system disturbances and keep power flowing. In this project, the maximum generation available to the program was approximately 5.7 megawatts.	Use of the generators by the utility was constrained by new regulatory rules adopted in January 2013 that served to hamper PGE's ability to test the engines in the transactive system. The utility conducted one brief test in 2014, and believes there remains potential for this approach to produce savings (perhaps more than $85,000 annually) from improved reliability and avoided energy costs.

Battery storage in a high-reliability zone: A novel 5-megawatt, 1.25-megawatt-hour lithium-ion battery energy storage system with custom grid-tied inverters was constructed and housed in PGE's new 8,000-square-foot Salem Smart Power Center. The battery system, designed to be part of a microgrid (discussed below), offers potential economic and reliability benefits through peak demand reduction; service outage avoidance or duration reduction; load reduction during the costliest supply hours; and mitigation of intermittent renewable energy generation.	This project element focused on constructing the energy storage system and testing its operation. Testing began in summer 2013, with the most useful data coming between November 2013 and August 2014. Data suggests full-cycle efficiency of charging and discharging was approximately 88 to 91 percent. The system operation, however, could not be correlated to the magnitude of transactive control signals, which had little or no influence on charging behaviors. Had the battery system been consistently responsive to the magnitude of the signal, it would have charged using lower-cost power and discharged when prices were higher. Testing suggested the capacity of the system had been somewhat understated by the battery vendor; consequently, PGE may be able to narrow its cycle depths and extend the useful life of the system. Going forward, PGE continues to see the battery system delivering both economic and reliability benefits.
Distribution switching and residential/commercial microgrid: PGE installed four automated switches to provide automatic fault location, isolation and segmentation of a distribution feeder to increase reliability. During the transient loss of power, the 5-megawatt battery and inverter system at the SSPC was to provide power until backup generators could be brought on line. PGE sought to demonstrate the ability of the microgrid to operate independently from the main grid, and also the ability to re-synchronize the microgrid and restore power from the main grid without a power outage.	Microgrid configurations were tested, but no outages or other events occurred during the project on this feeder, so no change in the reliability of the demonstration circuit could be shown. PGE has conducted a series of tests in preparation for microgrid operation. The tests involved individual vaults or racks from the battery system as well as generator and laboratory loads. However, at the time of this report, although thoroughly tested, the high-reliability zone has not yet been operated as a microgrid.

*Demonstration project funding was used only for data management services and development of monitoring/control software.

Final Observations

The Salem Smart Power Center—and its battery and inverter system—is an innovative, first-of-its-kind project. Virtually all systems tested by PGE were new and unique. The center demonstrated the ability to island a microgrid with utility-scale storage and customer standby generation, operate demand response, respond to a transactive signal, and how to integrate these complex resources into a single control system. As a result of the project, PGE offers several key takeaways:

- Thoroughly vet vendors' capabilities and financial strength.
- Take advantage of consulting talent within and outside the company to assess and mitigate risk.
- Perform and document ample testing, especially when there is a potential to impact commercial and residential customers.
- Establish a robust set of safety requirements.
- Assemble a strong, adaptable engineering and project management team.

The SSPC offers a substantial infrastructure resource for the future. The center also has shown its value in engaging the public in the smart grid discussion—hundreds of students and community members have toured the novel facility since it opened in May 2013.

University of Washington

UNIVERSITY of WASHINGTON

The University of Washington (UW) in Seattle is a premier research institution with an average daily population on campus of 60,000 people. More than 250 of the university's buildings on the Seattle campus are temperature conditioned. UW is Seattle City Light's second largest commercial customer.
The university's monthly electricity bill is approximately $1 million.

Demonstration Project Focus

Through its involvement in the demonstration project, the UW sought to gain a more detailed understanding of energy use across its campus, enhance efficiencies, involve students, and make the entire campus community more intelligent about energy use.

The University of Washington's demonstration projects were:

- Steam turbine, responsive to transactive control signals
- Diesel generators as demand response assets
- Solar renewable generation
- Direct digital building controls
- Building advanced metering displays and energy hubs
- Facilities Energy Management System (FEMS) data for campus building managers.

University of Washington's Cost Share: $5.1 million

Projects/Results at a Glance

Project Description	Outcomes
Steam turbine: The UW deployed an existing 5-megawatt steam turbine generator with provision to respond to transactive control signals from the demonstration project. The objective was to test the demand response operation and identify opportunities for sustained generation increases to pricing incentives or regional renewable energy integration strategies.	The transactive system engaged the turbine during the winter of 2013-14 and summer of 2014 a total of 136 times, or about 450 hours of operation. Because of very different winter and summer operational modes, the demonstration project developed separate models to characterize baseline operation. It appears generation increased by approximately 250 kilowatts at the times when generation had reportedly been increased during the winter analysis period; generation increased by about 470 kilowatts during summer events.
Diesel generators: Two existing standby generators were made available for added generator output. The generators' availability for providing additional capacity to the grid was limited in time and duration to accommodate periodic generator testing requirements and to remain within constraints of UW's existing environmental permit requirements. The objective was to test demand response operation and identify opportunities for sustained generation increases in response to pricing incentives or regional renewable energy integration strategies.	The demonstration project has little evidence that UW changed the way it engaged its diesel generators in light of either the events that were advised by the demonstration project's transactive system or the events that were reported by UW to have affected the diesel generators. It can be confirmed, however, that the two generators achieved their total nameplate ratings (capacity for sustained power output) of more than 4 megawatts during the demonstration project.
Solar renewable generation: UW provisioned two existing small-scale solar PV panel facilities for inclusion in the project. The facilities were intended to inform the UW regarding cost/benefit of future deployment of larger-scale solar PV facilities. The total capacity of the two facilities was 73.4 kilowatts.	The demonstration project estimates that the PV generation resources could generate about 68 megawatts per year that would displace approximately $4,300 worth of energy that the campus must presently purchase. To achieve this though, all the PV resources would need to be online throughout the year.
Direct digital building controls: Five buildings on campus received direct digital controls that allow heating, ventilation and air conditioning (HVAC) systems and lighting to be controlled using a "human-in-the-loop" transactive control strategy. The buildings were made available for operation at reduced load during low occupancy periods, as a demand response asset.	There were 26 individual events during which the buildings responded to calls for load reduction. The events typically lasted between a half-hour and a little more than three hours, with the shorter events being more common. An engagement level ("Tier 3") that affected all five buildings was defined by the university and chosen for analysis by the demonstration project. In terms of demand response value, analysts were unable to identify any significant impact.

Building advanced metering displays and EnergyHub© devices: UW installed advanced electrical sub-meters and EnergyHub© switch controls for two dormitories and two academic facilities that have a combined mix of laboratories, classrooms, and offices. The purpose was to make energy consumption data readily available to residents and researchers, with the idea that availability of information would reduce demand and encourage conservation. The sub-meters collected power use data and sent it to a central data warehouse, which made the information available. As part of this project, select students also were provided weekly energy tips on a display in a common area.	The system was installed and active by January 21, 2013. Power use data for the affected buildings exhibited some discontinuities, so the demonstration project elected to focus on the power measurements at a single building that offered fairly complete power data and fewer discontinuities. Based on analysis, it's possible that this project's displays/devices and student access to information might have resulted in an average daily 9.25 kilowatt power reduction for the building, but this also might be attributable partly to other UW energy conservation efforts. Data from a student survey suggested that students had not been motivated to change their energy consumption through education or the automation that had been provided them.
FEMS data for campus building managers: The UW designed, procured, and installed a FEMS, which is an enterprise platform interface and information system. The FEMS was designed to receive sub-metering information from all of the enabling and responsive assets associated with the UW's demonstration projects. Using information stored by the sub-meters in the database warehouse, the FEMS delivers access to reports and data, and provides dashboard visualizations and energy comparison graphics for web-based displays. The FEMS purpose was to provide real-time energy use information to UW, building managers and the campus community.	One of the products from this project was the web-based UW Energy Dashboard. The dashboard was created to provide current information and visualizations about building energy consumption and campus solar energy generation. The tool also provided consumption/generation info for the current day, the past week, and past years. In addition to UW buildings staff, the website is available to any member of the public who is interested in the information. The demonstration project was not able to identify a method to separately determine the impact from real-time energy information using the data supplied by UW.

Final Observations

Before the demonstration project, the University of Washington had just seven meters on its Seattle campus to monitor energy use. Now there are more than 200 smart meters acquiring near-real-time data about energy consumption every five to 15 minutes, which is displayed on its Energy Dashboard website. The university views its participation in the demonstration as a long-term investment in assets that will help the school better understand how its buildings use energy, which will make the campus community more intelligent about UW's energy use overall. The university calls it "a change in UW's relationship with electricity."

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Recommendations: Future Improvement and Research Needs

The demonstration project identified a number of areas where improvements in approaches and technologies, as well as additional research and development, can help advance future smart grid implementation.

Interoperability and conformance

Issues: Many participating utilities reported that the communications capabilities of various system components they installed were not interoperable—i.e., didn't readily work together—and were difficult to integrate. Further, some advanced metering and distribution metering systems were limited in their abilities to provide useful data. There also were instances of vendors not meeting expectations for product quality and technical support.

Recommendations: Improvements in interoperability standards and conformance testing will reduce equipment integration costs, while third party-testing might provide independent verification of vendor claims. Additional research is needed in distributed energy resources integration to identify functional/architectural requirements utilities can use to plan system upgrades.

The transactive system

Issues: The project's transactive system operated for nearly two years and demonstrated transactive control's potential. However, more work is needed in capability enhancements that allow accurate prediction of supply and load several days into the future; increased automation; and improved asset designs that flexibly enable devices to take better advantage of transactive system benefits. The project also found that utilities became more engaged in the system when they had more information at their fingertips.

Recommendations: The demonstration project recommends that future systems offer dashboards that display local transactive signal and responsive asset status. The project also suggests:

- Improved load modeling and forecasting techniques
- Enhanced methods to translate operational objectives into a monetized form for creating incentive signals
- Development of asset system model libraries to construct asset-specific transactive algorithms
- Technical/policy research identifying value streams for utilities/customers based on continuous responsive asset engagement via transactive signals
- Use of control systems analysis to identify stability and convergence requirements.

Data and data collection

Issues: There's a lack of tools available to utilities to handle the diversity and large quantity of data from the grid. Further, project analysts sometimes found it difficult to review the data in the form received, which led to time delays. Also, for time interval data records, the project's operation across multiple time zones—and application of the associated standard for data submission—proved problematic.

Recommendations: Better tools/techniques are needed for utilities to operate and maintain smart grid equipment, and ensure components deliver valid data. New distribution system situational awareness tools would help operators monitor the status of smart grid systems, and model-based assessment of sensor-system and intelligent end-device operation would offer abnormal operation detection. There also is a need for improved data management and decision support tools, such as a visualization capability, to harvest full benefit from the data.

Reliability assets

Issues: Six utilities installed technology to avoid outages and reduce durations. In the Northwest, reliability and power quality are already good, which makes it difficult to observe improvements. Project analysts were unable to confirm reliability improvements from the installed technologies based on standard reliability indices.

Recommendations: Standard approaches to modeling and simulation of reliability improvements, with models validated using live data, are needed. This can improve the consistency of calculations in back-office systems and aid evaluation of reliability-related investment benefits.

Conservation/efficiency assets

Issues: About one-third of demonstration asset systems were tested for long-term conservation and efficiency impacts. Previously cited issues of data quality and situational awareness also apply here.

Recommendations: Research that improves the ability of utilities and asset owners to operate information-enabled conservation and efficiency technologies will help assure the quality and integrity of data generated by these systems.

Dynamically responsive (transactive) assets

Issues: Utilities found asset system communications components were not especially interoperable, requiring engineering integration. Devices also are not yet smart enough to manage tradeoffs between customer comfort and grid needs. And, the largest controllable loads maintain human control, which often limits the availability and reliability of the assets' responses.

Recommendations: Automation is important in coordinating decision-making and responsive asset actions. Research is needed to further develop and deploy automated systems, both within the utility infrastructure and in customer premises; associated outcomes must include building utility and customer confidence in the systems' use. Research also is needed around the policy for customer incentives. It must be determined whether dynamic cost signals will be used as a dynamic tariff, or alternately that periodic compensation, such as monthly capacity payments, is preferred.

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