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Pacific Northwest Smart Grid Demonstration Project Technology Performance Report Volume 1: Technology Performance

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Executive Summary

The Pacific Northwest Smart Grid Demonstration (PNWSGD), a $179 million project that was co-funded by the U.S. Department of Energy (DOE) in late 2009, was one of the largest and most comprehensive demonstrations of electricity grid modernization ever completed. The project was one of 16 regional smart grid demonstrations funded by the American Recovery and Reinvestment Act. It was the only demonstration that included multiple states and cooperation from multiple electric utilities, including rural electric co-ops, investor-owned, municipal, and other public utilities. No fewer than 55 unique instantiations of distinct smart grid systems were demonstrated at the projects' sites. The local objectives for these systems included improved reliability, energy conservation, improved efficiency, and demand responsiveness.

The demonstration developed and deployed an innovative transactive system, unique in the world, that coordinated many of the project's distributed energy resources and demand-responsive components. With the transactive system, additional regional objectives were also addressed, including the mitigation of renewable energy intermittency and the flattening of system load. Using the transactive system, the project coordinated a regional response across the 11 utilities. This region-wide connection from the transmission system down to individual premises equipment was one of the major successes of the project. The project showed that this can be done and assets at the end points can respond dynamically on a wide scale. In principle, a transactive 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.

PNWSGD: Assembling the Team and Initial Steps

The origins of the demonstration project and eventual deployment of the transactive system can be traced to a Request for Interest jointly issued by the Bonneville Power Administration (BPA) and Battelle Memorial Institute in 2009. Many prospective PNWSGD participants responded to the request, and from these, ten distribution utilities and the University of Washington campus were chosen as demonstration test sites. Because of the BPA's interest in this research, the demonstration's geographical extent naturally included much of the Pacific Northwest. The selection of the 11 participant sites extended the region to represent five Northwest states—Idaho, Montana, Oregon, Washington, and Wyoming. The PNWSGD worked with each of these site owners to understand and document how the smart grid assets to be tested at each site were distributed among and monitored within its distribution system. In short, the project was one of the first and largest efforts to experiment with how to actually implement a smart grid.

Five additional organizations that came to be called "project-level infrastructure providers" were selected to apply their systems expertise, which was critical to the development of the transactive system. 3TIER (now Vaisala) offered measurements and predictions for most of the wind generators. Alstom Grid helped calculate the transactive signals. International Business Machines Corp. (IBM) was the system's chief architect and simulated transactive system performance. QualityLogic, Inc., offered system testing and interoperability expertise. Netezza, which was purchased by IBM during the PNWSGD, offered its massively parallel database appliance. During the course of the project, Spirae, Inc., was added to the group with the task of supporting the utilities in their deployment and testing of their transactive system components. Battelle Memorial Institute's Pacific Northwest Division (operator of the Pacific Northwest National Laboratory) was asked to be the technical and organizational lead.

The PNWSGD was accomplished in four phases that were scheduled for the timely installation of smart grid hardware and software and the new transactive system. A kickoff meeting was held in December 2009 to share and align participants' expectations for the demonstration. The project followed an aggressive schedule to complete its designs and installations by mid-2012, which was planned to allow for a two-year data collection window before the end of August 2014. Closeout activities, including the drafting of this final technical report, continued into 2015.

Engaging Electricity Users and New Technologies

Although all of the PNWSGD partners played pivotal roles in the project, the demonstration test sites, and their interfaces with the customers who eventually will use and benefit from smart grid technologies, were particularly important elements of the project. One objective of a smart grid is to improve the reliability of electric power for its end users. Toward this, PNWSGD utilities automated their distribution systems to enable more rapid restoration of customers' power after outages, including the application of fault detection, isolation, and restoration. Several of the project's utilities took advantage of automated power-quality alerts that have become available from advanced premises metering to help them more quickly pinpoint and respond to outages, abnormal supply voltages, and other conditions. Still others installed batteries and automated distribution switching to define high-reliability zones, including some that may separate from the rest of the grid and operate as microgrids when they become threatened by power outages.

Another objective of a smart grid is to conserve energy and improve the system's overall efficiency. One of the simplest means to conserve energy is to replace existing equipment with more energy efficient alternatives, as Avista Utilities did when they replaced approximately 800 existing distribution transformers with more efficient smart transformers. Others changed and automated their management of their distribution systems. Examples include using reduced feeder voltages that reduce the power consumed by some end-use loads, correction of power factor that reduces power line losses, or coordinated volt and reactive power control that can both reduce power load and reduce system losses.

Information itself can motivate consumers to conserve energy. Several of the participating utilities informed their customers of their historical electricity consumption via web portals or in-home displays. The University of Washington campus greatly increased the metering of individual buildings on its campus, and it generated new methods to inform building managers and occupants of their historical energy practices, either monthly or in real time. A very interesting effort at the campus was to empower its students, giving them tools to manage energy in their dormitory rooms and engaging them still further via social media.

The participating utilities reported a variety of benefits from their participation in the project and the smart grid technologies they deployed. Anecdotal reports of their experience have been compiled as “A Compilation of Success Stories” by BPA.[1]

Bringing Transactive Concepts to Life

The technical centerpiece of the project—the glue that connected the test sites, technologies and electricity resources—was the transactive system, which was implemented to dynamically respond to emerging conditions in the region’s power grid. The transactive system was distributed, providing a means of coordinating behavior of demand-responsive components through a forward-looking incentive signal and forward estimates of load behavior. The transactive system produced incentive signals, constructed by blending energy costs and conditions of the region’s bulk generation and grid. The system’s incentive signals were dynamic in space as well as time, representing variability across 14 geographic zones within the BPA balancing area based on location of the region’s bulk generation resources. The system of incentive signals predicted the delivered costs of energy in the near term and several days into the future. Large demand-side resources engaged by the transactive system included distributed generation, campus chillers and heating, ventilation, and air conditioning, renewable energy generation, and stationary battery energy storage systems. Smaller demand-side resources, often installed at residential premises, included sets of communicating thermostats, water heater controllers, and smart appliances.

The region’s bulk generation and a simplified transmission structure were emulated for the project by Alstom Grid using their energy-management and market-management system tools. The condition of the region’s generation and transmission systems was informed by a combination of actual grid status and static, seasonal representations of diurnal patterns. The bulk delivered costs of electricity were also estimated from this process, much as is done today in regions where locational marginal pricing is practiced. It is the flexibility with which costs and incentives may be dynamically applied in this transactive system that may help mitigate challenges of wind intermittency, encourage economic efficiency, and flatten system load.

While the project’s transactive system did not engage demand-side assets as well as had been hoped, the project was understood from the beginning to not be large enough to by itself have an impact on the grid. A bold step had been taken by the demonstration to launch the transactive system so generally, across such a large region, and to include its predictive days-ahead planning horizon. In order for the system to have been fully proven, no fewer than eight subsystems would have necessarily been accurately and meaningfully deployed. A key result of the project is, however, that much of the transactive system worked as intended. Experience with the transactive system helps prepare the region to operate an increasingly distributed electric power system making maximum use of its growing renewable energy supply and demand-side solutions. The project leaves an updated technical specification for the transactive system that leverages the five years of development and deployment experience. The updated

[1] Bonneville Power Administration. 2015. Pacific Northwest Smart Grid Demonstration Project: A Compilation of Success Stories. Accessed at https://www.bpa.gov/Pages/home.aspx.

specification and a corresponding reference implementation provide an important platform for future research into transactive energy systems.

When the project looked at the transactive subsystems (as is done in Chapter 2), about half of the subsystems were found to have performed well. Among the successes, wind resources were accurately stated and predicted within the region by the demonstration. 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.

There is a key observation about the performance of the transactive coordination system as compared to conventional demand response. Even when the responses to the transactive system were automated, utilities placed limits on the number of allowed responses. Customer agreements often specified a maximum number of allowed events in a month. Conventional demand-response programs, either direct load control or otherwise, are generally event-driven and are targeted toward managing few, short-lived incidents like critical peaks. Several well-placed asset responses may be adequate for conventional demand-response programs. Transactive systems, on the other hand, reveal a continuum of incentives to the utilities and asset systems and could engage assets much more dynamically according the each asset’s capabilities and the flexibility of the asset’s owner. This granularity of responses by many customers enables those customers who are both willing and able to respond (via automated systems) to participate according to their preferences rather than having their participation limited according to predetermined agreements.

In addition to the results gained from the deployment of the transactive system, IBM used a model of the regional system to assess the impact of a scaled up deployment of the transactive system. This simulation showed that the region’s peak load might be reduced by about 8% if 30% of the region’s loads were responding to the transactive system.

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 the 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 PNWSGD utilities could, in principle, resume the use of their transactive systems.

Exploring Data—and Associated Challenges

Now that the demonstration project has concluded, it leaves behind a rich database—almost 350 billion data records. Organization of the data is based on the 55 smart grid systems defined by the project. An extraordinary effort was needed to accurately specify the many data series that might be used to monitor those smart grid systems. The disparity of data sources, databases, intervals, and utility data practices that was encountered during the demonstration made the challenge even greater. The transactive system featured a predictive time dimension that exponentially increased the volume of data that was automatically collected from the transactive system.

The project's experience is an example of dealing with the vast amounts of new data that become available in a smart grid. In the demonstration, much of that data was found to be unusable. Data cannot be converted into actionable information if its quality is poor or if its units, location, or validity is uncertain. Investments should be made to improve the quality of meter data, databases, and smart grid data processes at all levels. As a part of these investments, there is a need for better tools to be developed for utilities to use in managing the devices and information found in a smart grid.

Moving Forward

Along with data challenges, this report addresses the technical performance of all the smart grid asset systems that were tested at the PNWSGD sites. It also critiques the performance of the transactive system that was featured by the demonstration. After an introductory chapter, the performance of the transactive system is discussed. In the three following chapters, the performances of reliability, conservation and efficiency, and demand-responsive systems are generalized, referring to the 55 smart grid systems that were demonstrated at the PNWSGD sites. The performance of each site owner's smart grid systems is presented in the final 11 chapters.

At its conclusion, the PNWSGD leaves a legacy of smart grid equipment installed with its site owners. Eighty-eight percent of the smart grid assets remain installed and functional after the demonstration. The remainder succumbed to the challenges of grid modernization in the early 21st century. Some of these systems could not be successfully integrated due to interoperability problems with other new and legacy systems with which they needed to interact. Some sets of residential devices were removed after having been installed, due to unexpected safety problems or at the request of residential customers. Some vendors failed to deliver their smart grid products or went out of business during the demonstration. Nine of the removed systems were wind turbines that were taken down at a renewable park due to safety concerns after a tower catastrophically failed and a turbine had thrown a blade. These are considered learning experiences. The demonstration project facilitated the maturation of the smart grid industry, and helped advance our collective thinking about the path forward. Please read further to understand why the participants in the PNWSGD remain optimistic about smart electric power grids of the future.

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Acronyms and Abbreviations

3TIER	3TIER, Inc., now part of Vaisala
ACS	advisory control signal
AGRS	Avista-generated request signal
AGS	Avista-generated signal
aHLH	average heavy-load hour energy
AMI	advanced metering infrastructure
BPA	Bonneville Power Administration
CAIDI	Customer Average Interruption Duration Index
CPUC	California Public Utilities Commission
CVR	conservation voltage reduction
DA	distribution automation
DDC	direct digital control
DMS	distribution management system
DOE	U.S. Department of Energy
DR	demand response
DRU	demand-response unit
DSG	distributed standby generation
EIOC	Electricity Infrastructure Operations Center
FDIR	fault detection, isolation, and restoration
FEMS	facility energy management system
GE	General Electric
GFA	grid friendly appliances
HAN	home area network
HLH	heavy-load hour
HVAC	heating, ventilating, and air conditioning
IBM	International Business Machines Corp.
iCS	Internet-Scale Control System software
IEEE	Institute of Electrical and Electronics Engineers
IHD	in-home display
IM	impact metric
IST	interval start time
IT	Information Technology
IVVC	integrated volt/VAr control
LCM	load-control module
LLH	light-load hour

LTC	load tap changer
LV	prefix for Lower Valley, Wyoming, project tests
MAIFI	Momentary Average Interruption Frequency Index
MAN	metropolitan area network
MDM	meter data management
O&M	operations and maintenance
OMS	outage management system
OMT	Outage Management Tool
p.u.	per unit
PCT	programmable communicating thermostat
PHEV	plug-in hybrid electric vehicle
PLC	power line carrier
PNWSGD	Pacific Northwest Smart Grid Demonstration
PRB	Project Review Board
PUD	Public Utility District
PV	photovoltaic
RTU	remote terminal unit
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	supervisory control and data acquisition
SCL	Seattle City Light
SEL	Schweitzer Engineering Laboratories
SSPP	Salem Smart Power Project
ST	field site node (of the transactive coordination system topology)
STP	Smart Thermostat Pilot
SVC	static VAr compensator
T&D	transmission and distribution
TFS	transactive feedback signal
TIS	transactive incentive signal
TWACS	Two-Way Automatic Communication System
TZ	transmission zone
UC	unit commitment
UW	University of Washington
VVO	volt/VAr integration and optimization
WECC	Western Electricity Coordinating Council
WSU	Washington State University

Units

$/h	dollars per hour
°C	degree(s) Celsius
F	Fahrenheit
GW	gigawatts
GWh	gigawatt-hour(s)
kV	kilovolt(s)
kVAr	kilovolt-ampere(s) reactive
kW	kilowatt(s)
kWh	kilowatt-hour(s)
kWh/h	kilowatt-hour(s) per hour
m	meter(s)
mph	miles per hour
MW	megawatt(s)
MWh	megawatt-hour(s)
p.u.	per unit
s	second(s)
VAr	volt-amperes reactive
W	watt(s)
y	year

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