6.0 Conclusions

The Pacific Northwest Smart Grid Demonstration (PNWSGD) was among the most expansive, inclusive smart grid demonstrations ever conducted. Nineteen organizations participated directly in the PNWSGD. Many other product and service vendors worked tirelessly to supply, install, and support the smart grid equipment that the PNWSGD installed at its various field sites. Many residential, commercial, and industrial electricity customers accepted and interacted with the project's smart meters, displays, and controllable premises-level equipment. Still more individuals trusted their utilities to install and demonstrate novel distribution tools, like distribution automation and distribution-scale battery systems.

This section concludes the reporting of PNWSGD technical performance. After stating some general conclusions, conclusions about the project's transactive system are stated. Given the project's massive data collection efforts, some comments are offered concerning the challenges encountered by the project concerning its data and data collection. Then, some conclusions about each of the three asset categories—demand-responsive (i.e., transactive), conservation, and reliability—are provided. At the end of each section, future research topics addressing the conclusions are listed.

6.1 General Conclusions

The PNWSGD was funded by the U.S. Department of Energy, in part, for economic stimulus. The utilities participating in the project spent about $80M on the region's smart grid infrastructure, and about 88% of that investment remains installed and useful. A project infrastructure highlight is the Salem, Oregon high-reliability zone and its 5 MW distribution battery energy storage system. The buildings on the University of Washington (UW) campus in Seattle, Washington, were largely unmetered prior to the project, but they are now well metered and support continuing conservation efforts on that campus. Residential advanced metering infrastructure (AMI) system installations have been completed throughout six of the project's demonstration communities, and this infrastructure was finished, in part, using support from the U.S. Department of Energy and PNWSGD. Altogether, some 31 thousand AMI end points worth about $21M were installed by the project, and the project utilities reported that another 46 thousand existing meters participated directly or indirectly in the demonstration. Innovative distribution control features and systems were installed at seven of the project's distribution sites.

The project achieved several noteworthy results, including the following:

- The transactive system was deployed, tested, and validated, providing region-wide connection from the transmission system down to individual premises equipment, enabling dynamic response by assets at the end points.
- The participating utilities gained valuable experience in the challenges of deploying and operating smart grid equipment and in the benefits of the equipment in their systems. This experience is guiding their ongoing smart grid investments.
- The basic functionality of the transactive system was confirmed and scale-up analysis using modeling and simulation showed potential for 8% reduction of regional peak load with 30% penetration of demand responding to a transactive system.

Generally, the installations were not easy. Many of the participating utilities reported among their lessons learned that the communications capabilities of various system components were not interoperable. The source of the incompatibility was sometimes different versions of rapidly evolving communication standards, but even system components that were said to use the same standard were not easily integrated.

Some of the product vendors in the smart grid space, too, were found to be immature companies and were at risk of failing. Sets of skid-mounted battery energy storage systems were installed by two of the project's utilities but were unsupported and abandoned when the products' vendor ran into financial difficulties. Several vendors of small, renewable wind and solar generation systems were unable to deliver their products or delivered products that never generated significant energy.

Utilities were free to select their own preferred AMI systems. Not all of the selected AMI systems were found to be equal. In the Pacific Northwest (PNW), where time-of-use retail tariffs are not commonly used, utilities have been selecting their retail meter systems to remotely read meters, remotely disconnect and reconnect service, or automatically report customer outages. Interval power metering is perhaps of secondary importance. The meters' limitations became evident as the project requested from its utilities relatively fine-resolution power data for each premises. In the worst cases, a utility's power line carrier-based AMI system could not collect its customers' interval data at intervals shorter than 1 day.

Limitations were also found for distribution metering. While the smart grid community is promoting AMI, many utilities do not yet have complete supervisory control and data acquisition systems. Distribution metering, where it existed, sometimes included an incomplete set of measurements that did not even support measurement of the impacts that were to be demonstrated.

These challenges suggest that there is a continued need for work on interoperability standards and conformance testing to reduce the cost of integrating smart grid equipment. Third-party testing may be useful to provide independent verification of vendor claims. These general results also underscore the importance of practical, affordable upgrade paths for smart grid systems. Current research on integration of distributed energy resources should identify functional and architectural requirements that utilities can use to plan these system upgrades. As utilities respond to these new requirements, it is desirable that their recent smart grid investments have appropriate upgrade possibilities rather than becoming stranded assets.

6.2 The PNWSGD Transactive System

The PNWSGD featured a transactive system that was designed to incentivize dynamic, distributed changes in electric load that would, in turn, improve the scheduling and dispatch of the region's energy supply. The system was specified, designed, implemented, and ran for nearly two years. During the two-year period the transactive algorithms were tested and refined. Observation of the dynamics of the transactive signals relative to regional grid conditions verified the basic correct functionality of the transactive system. The experience of the project in deploying, testing, and operating the transactive system helped prepare the region to deal with an increasingly distributed grid capable of making maximum use of renewable energy resources and demand-side solutions.

It proved extremely difficult to demonstrate a distributed transactive system in the PNW. The region does not have a structured electricity market that could provide a starting point through, for example, locational marginal prices in the transmission system. Due to the predominant use of bilateral agreements for power purchase, much of the information needed to create the transactive incentive signals at the regional level was difficult to obtain. In spite of this, through the efforts of the Bonneville Power Administration and 3TIER, enough information was available to enable sufficient creation of regional signals using the Alstom models that represented the changing nature of resource availability to demonstrate functionality of the transactive system. Based on the understanding gained through this activity, the region is much better prepared to identify specific operational objectives and opportunities for applying a transactive system, for example, to engage demand-side systems to support wind balancing reserves.

The PNWSGD represented the region's generation and transmission using an "informed simulation." The informed simulation received some real-time status information, including accurate wind generation, but much regional status information had to be derived from representational season trends. The informed simulation had to infer the scheduling tradeoffs and priorities where specific information was lacking and for all of its hour-ahead and day-ahead predictions. A set of interim parameters were defined, by which the influences of multiple resources and incentives could be declared and blended into a single incentive signal. These parameters should be considered as a useful tool at this point, a potential interoperability boundary. The outputs of the informed simulation included a dynamic, location-specific incentive signal that was to represent the delivered cost of electricity at each location and time.

In order to conduct the planned experiment, the project members had to effectively simulate the equivalent of an organized regional market such as PJM Interconnection or Midcontinent Independent System Operator. This is not a trivial task in view of the large investments required to create those markets. According to the project's conceptual model, each of the region's generator sites should have been represented by its own transactive system node, not in aggregate, as occurred in the informed simulation. The project simplified its nodal topology for expediency. But this simplification also allowed the project to defer the solution to an unsolved technical challenge: in a meshed transmission network, the power flow solution must be integrated with the transactive system and must be solved in a distributed fashion. Each site in the transactive system's topology may be assumed to know only its local status. There is no universal reference for voltages in a truly distributed calculation. If this technical challenge is unsolved, a node in a meshed network cannot accurately allocate its export of power to more than one of its neighbors.

Analysis of the transactive system's incentive signals confirmed that they exhibited meaningful responses relative to the resource information used in the informed simulation. Comparison to actual events in the BPA system confirmed that where the informed simulation was capable of representing such events, the events had been represented by the transactive system. Further, the corresponding events advised by the transactive coordination systems at the utilities' responsive assets were often observed to be sensible, though the utilities were often not able to dispatch the corresponding asset system(s).

The PNWSGD transactive system, as implemented in the PNW, could not, in fact, directly influence the region's resource mix at all due to the use of the informed simulation to represent the bulk power system. That meant that part of the conceptual control loop could not be demonstrated. However, a simulation by International Business Machines Corp. closed the control loop and allowed the PNWSGD to simulate the impacts of much higher penetrations of transactive assets and wind generation than achieved and existing in the PNW. The simulation showed that the region's peak load might be reduced by about 8% if 30% of the region's loads were responsive to the transactive system. The simulation also showed that battery energy storage also took advantage of the lowest-cost time periods in a transactive system to recharge its batteries. The interplay between wind energy, seasonal variations, and the impacts of the transactive system was complex and warrants further study.

Unlike previous transactive system designs, the PNWSGD system included a predicted future dimension. All of the system's signals were to include predictions up to several days into the future. We believe this was an important advancement, allowing both supply and load resources to not only react, but also to plan their strategies. In practice, the future predictions were error prone. The incentive signals generated by the informed simulation, for example, exhibited a persistent bias prediction error for predictions more than about 3.5 hours into the future. The responsive asset systems that reviewed the incentive signals to plan their future responses were, of course, confused by the incentive signal's bias errors. Early in the project, many of the daily-event asset systems would review the future incentive signals that they received at the start of a new day, conclude that the future costs were only going to get higher (based on the prediction biases in the signals they had received), and opt to respond now (at midnight) rather than wait.

Utilities largely relied on functions that were designed, configured, and provided to them by the project. One such function predicted the utility sites' bulk electric load. The training of the function was done in bulk, using historical electric load files that had been provided by the utilities. The project analyzed both the relative and absolute accuracies of these load predictions. The absolute accuracies were poor when the training set had been small or unavailable. More future work is recommended to achieve accurate load predictions for distribution utility systems.

A set of functions was also developed to represent the systems of responsive assets that had been installed at the PNWSGD utility sites. These functions determined event periods and automatically advised the asset systems when they should respond. The functions' configuration helped tailor the advice to the asset owners' preferences and objectives. For example, a set of demand-response units (DRUs) could be configured to allow no more than five responses in a month if that were the number of responses promised to the DRU households by its utility. System models estimated the change in load that would accompany the responses. This functional approach for representing the responsive asset systems in the transactive system, while challenging to implement, proved remarkably flexible and resilient. The quality of the resulting advice and modeled impact corresponded to the care with which the functions had been created and configured. The timing of the advised events was found to correspond pretty well to the times that the transactive incentive signals had been relatively high. These functions and their prediction algorithms are a rich area for future research.

Relatively few events were found to have been conducted coincident with the times that the transactive system had requested events. Some of the utilities' reluctance to accept advice from the transactive system was understandable. Early in the PNWSGD, the quality of the incentive signal was poor. This early performance resulted in mistrust of the incentive signal that was not later re-earned. In addition, the transactive incentive signal was not used for revenue purposes, so responses to the incentive signal were not financially rewarded. Furthermore, some of the largest responsive systems lacked automation and relied on human intervention to dispatch events. Functions could be designed to better accommodate systems that lack automation, but the responses of such systems probably will not provide the flexibility that will be needed in future smart grids.

The commercially available responsive asset systems that were implemented by the PNWSGD, while appreciated, probably fell short of the smart grid capabilities that could be supported by a transactive system. First, there were simply too few responsive assets. If the smart grid community truly wishes to avoid dispatching its last resource, for example, the aggregate magnitudes of the available responses must be comparable to both the power and energy of the resource that is to be deferred. Second, each device must offer more responses and more dynamic responses. One surprise during the PNWSGD was that the project's battery system vendors advised or specified that their batteries not be charged and discharged more than about one cycle per day. This limitation potentially limits the grid services that can, in fact, be provided by the batteries. Third, the devices should be designed to take advantage of *both* high-cost disincentive periods and low-cost incentive periods. Especially in the PNW, balancing authorities need more resources that can usefully consume additional energy on demand.

The PNWSGD transactive system design was formalized as a state machine model with corresponding formal definitions of the transactive signals. The design was instantiated in a reference implementation with a corresponding test harness. These project products provide valuable tools for further research, development and deployment of transactive systems.

The PNWSGD also recommends that future transactive systems facilitate dashboards that show the status of the local transactive signals and local responsive assets. Anecdotally, the utilities that had developed their own dashboards became better-informed participants. In its second demonstration year, the PNWSGD developed such dashboards for each of its utility participants and displayed them on Webpages that were accessible by the utilities. This access to the previous day's information seemed to educate participants and rejuvenated their interest in the transactive system.

Based on the experience of the PNWSGD, several further research and development topics associated with the deployment of transactive systems are listed here:

- development of improved load modeling and forecasting techniques
- methodologies for translation of operational objectives into monetized form as the basis for creating transactive incentive signals
- development of libraries of asset system models to be used in construction of asset-specific transactive algorithms
- technical and policy research identifying value streams for utilities and their customers based on continuous engagement of responsive assets in response to signals from a transactive system
- control systems analysis of transactive systems to identify stability and convergence requirements.

6.3 Data and Data Collection Processes

The project analyzed impacts from the asset systems that had been installed at the project's utility sites. The PNWSGD strove to objectively confirm anticipated benefits using the meter data that the project collected.

Early in the project term, project staff met individually with the utilities to resolve what was to be tested and how the project might objectively confirm anticipated benefits. It was surprisingly challenging to resolve with the utilities precisely how many systems were to be tested and what the systems comprised. Some utilities accepted advice about how the demonstration components might be refined to improve the likelihood that impacts would be observed and would not be confounded by the behaviors of their other asset systems. Not all of the participating utilities were convinced that rigorous tests of assets' performances were necessary, preferring instead to test the ease with which the systems could be installed and the levels of satisfaction that were reported afterward by their customers.

Especially the smallest utilities preferred to contract out their data expertise. This worked in some cases, but not in others. Most participating utilities seemed challenged to access or accurately represent the data that they had at their disposal. The smart grid community should perhaps be concerned that in the midst of the vast amounts of new data that has begun to flow into utilities, the utilities' ownership and knowledge of its own data and data processes is often lacking. The most common errors encountered among the data received from utilities were mistaken applications of units of measure, incorrect meter scaling, and timestamp errors. Accurate data dictionaries are recommended at every stage of data collection to state the provenance of the data and to reduce uncertainties about its correct interpretation.

Project analysts were eventually able to resolve many, but not all, of the discrepancies. The project had limited automated data checking, primarily for the transactive system data. For the other test cases, the process was primarily manual. As a result, the analysts found it challenging to review the data as it was received, and often had time delays in resolving missing data or other inconsistencies with the utilities. This underscores the value of applying automated data checking whenever practical.

Time interval data records are inherently challenging. The project operated across multiple time zones. Therefore, the project had specified that data should be submitted using the coordinated universal time standard, which is independent of time zone and daylight standard time transitions. Utilities should indeed use the universal time standard, but the advice possibly caused as many errors as it avoided. The data collection team could not confidently assert which of the received data had been converted or not. The uncertainty was renewed near changes in daylight savings time, which might, or might not, have been correctly addressed by the sender.

One conclusion of the project is that better tools and techniques are needed for utilities to operate and maintain smart grid equipment. They must be able to observe that the intelligent end devices and other system components are operating correctly and providing valid data. There is a corresponding need for improved data management and decision support tools to get full benefit from the newly available data. As an example of such a tool, the project implemented a visualization tool as a means of making the transactive system data easier to evaluate for other researchers.

Research that can support improved means for utilities to deal with the onslaught of data from smart grid technology includes the following:

- standardized approaches to data quality, including methods and tools for continuous monitoring of data streams to assure that devices and systems are operating as intended
- distribution system situational awareness tools for operator monitoring of the operational status of smart grid systems

- model-based assessment of sensor-system and intelligent end-device operation, providing a basis for detecting abnormal operation.

6.4 Reliability Assets

Six of the PNWSGD utilities established fault detection, isolation, and restoration systems or took advantage of features of their AMI systems to avoid outages and reduce outage durations. The project attempted to verify that these systems had significantly improved their corresponding circuits' reliability. Toward this end, the utilities submitted one or more of the standard reliability indices chosen from among the System Average Interruption Frequency Index, System Average Interruption Duration Index, and Customer Average Interruption Duration Index. The utilities reported that their operational experience with the reliability improvements was positive.

Service reliability and power quality are already good in the PNW, and reliability events are infrequent. Project analysts were not especially successful at confirming improvements from these reported indices. For the few utilities that reported monthly calculations and supplied their indices from well before the systems had become installed and useful, significant improvements could not be detected. This is attributable, in part, to the unpredictability and natural randomness of outages, but there were other challenges, too. At least one utility was found not to have calculated the indices according to accepted practices. Little historical data was made available from long before to the installations. And uncertainty remained about precisely when and where the utilities were reporting their systems to have become activated.

There is nothing fundamentally wrong with the present set of reliability metrics. If they are to be used to validate trends and changes in service quality, as was the intention here, the utilities should calculate the indices monthly and for each circuit. Where monthly data was available, the project performed a Student's t test to objectively compare the service reliability before and after historical months. This method found some significant trends, but the trends were either contrary to expected outcomes or occurred at times other than when the utilities had reported their systems became active.

Some utilities reported outage minutes that they had avoided, a calculation derived, sometimes automatically, from their outage management systems. These numbers were quite favorable toward the applied technologies. However, this derived index begs the question, why don't these avoided outages appear to have affected the conventional index calculations?

Given that reliability events are infrequent, making it difficult to gather field data, there is an ongoing need for standard approaches to modeling and simulation of reliability improvements, with models validated using live data. This can improve the consistency of the calculations done in back-office systems and aid utilities in evaluating the benefits of reliability-related investments in smart grid technology.

6.5 Conservation / Efficiency Assets

Approximately one-third of the PNWSGD asset systems were tested for the impacts of long-term conservation and efficiency that they offered.

Efficient equipment. Two asset systems were implemented by Avista Utilities at the Pullman, Washington site to replace less-efficient equipment with new, efficient replacements. By replacing about 2 miles of inadequate distribution feeder lines, the utility estimated it will conserve about 29.6 MWh/yr. The utility also replaced aging transformers with efficient, smart transformers, which also offered useful new voltage and power meter points to the utility.

AMI. Several PNWSGD utilities wished to learn whether the installation of AMI itself or in combination with AMI, Web portals, or other devices affected premises energy consumption. By installing AMI in Pullman, Washington, Avista Utilities estimated it will save $235 thousand per year, mostly through operational efficiencies like reduced meter reads and truck rolls. In Idaho Falls, Idaho, the installation of AMI appeared to have reduced premises consumption by about 92 kWh per year, but the decrease could not be found for residents who had received both AMI and an in-home display (IHD). Lower Valley data suggested that its members conserved 270 W, on average, upon receiving AMI, but less (210 W) when they also received an IHD.

Similarly, the UW evaluated whether its building managers would conserve energy if informed by either its real-time facility energy management services displays or by simpler monthly reports made available to them.

Power factor correction. Both Idaho Falls Power and Lower Valley Energy invested in equipment that would improve their feeders' power factors. These efforts were successful and should reduce line losses from 7 to 30% on those feeders. Much of the impact was available from simple, one-time reviews and corrections of the affected feeders.

Voltage management. Six PNWSGD utilities demonstrated voltage management alone or integrated with reactive power management. Avista Utilities was confirmed to be able to conserve about 2% of its load in Pullman, worth approximately $0.5 million per year, using Integrated Volt/VAr Control. Idaho Falls and Milton-Freewater also demonstrated strong conservation savings on their distribution feeders. The performance of the Lower Valley Energy system was mixed and was found to have diminished after a strong project start. As was the case in Milton-Freewater, the short-term voltage reductions were calculated to have increased, not decreased, premises consumption. This preliminary finding warrants further investigation.

Renewable generation. The PNWSGD demonstrated 4 solar photovoltaic (PV) and 12 residential- or commercial-scale wind turbines. All of the PV systems performed well and generated power and energy commensurate with their system ratings. That was not the case for the wind turbines. Approximately half, once installed, generated significant amounts of energy, but the others never demonstrated their nameplate potentials. Two of the PV arrays and 11 of the wind turbines had been installed at an innovative community solar park in Ellensburg, Washington. Residents were able to buy shares of the park's renewable generators instead of installing their own. Regrettably, one of the turbine towers failed during the demonstration, and the city elected to remove all of the wind turbines, fearing danger to foot traffic in the park.

In general, conservation and efficiency is an area that is mature and well understood, particularly in the PNW. As smart grid technology is used for conservation and efficiency purposes, however, the challenges related to data quality and situational awareness apply. Research in improving the ability of utilities and asset owners to operate information-enabled conservation and efficiency technology is needed to help assure the quality and integrity of the data generated by these systems.

6.6 Dynamically-Responsive (Transactive) Assets

The PNWSGD demonstrated several classes of assets that may be dynamically controlled. The project established a transactive system and preferred that these assets respond to the transactive system's advice. The project intentionally did not prescribe to the utilities that they directly respond to the transactive system. In most cases, the utilities chose to have a conventional demand-response system, often with a "person in the loop," respond to asset control signals from their local transactive system node. In several cases, the conventional demand-response systems included customer participation agreements that limited the frequency and duration of responses. These systems could also be dispatched by the utility independent of the transactive system. The project analysts worked to quantify the assets' change in power consumption during events, regardless of how events had been initiated. The following classes of assets were demonstrated by the PNWSGD utilities:

Portals and IHDs. Participating utilities sent either binary event indicators or tiered pricing information to Web portals and IHDs. Building occupants, upon receiving these notifications, were to respond by voluntarily shutting off or deferring the operation of electric loads. An interesting finding at Flathead Electric Cooperative was that while a small power reduction occurred during IHD events, the impact seemed to continue past the end of the events. It was a *softer* response than what might be observed from systems that directly engaged electric loads. Unfortunately, Flathead Electric Cooperative chose to remove its IHDs amid concerns that audible beeps from the devices were irritating its members.

Thermostat systems. Three utilities installed communicating thermostats alone or as part of a larger suite of premises devices. The thermostats moved the temperature set points up or down by a couple degrees during events to reduce premises power consumption. The calculated impact, on average, was 52 W per premises at the Idaho Falls, Idaho site. The calculated impact might have been higher had there not been questions about the timing of the events and data available for additional months.

Heating, ventilation, and air conditioning (HVAC) control. At the two Washington universities, components of the buildings' HVAC systems were made responsive. Short-term curtailment of air circulating fans on the Washington State University (WSU) campus achieved a 240 kW reduction, and reducing chiller load yielded a 380 kW reduction. The UW campus implemented similar control on some of its buildings' HVAC systems.

DRU control of water heaters and air conditioning. At least five utilities tested load switches (DRUs, load-control modules, etc.) for the control of water heaters and other 240 V premises loads. This technology has become quite mature, and more than 2,200 such switches were installed by PNWSGD utilities. The confirmed curtailment impacts for these devices ranged from about 200 W to 370 W per device during the utilities' events. However, no significant impacts could be determined in Idaho Falls, Idaho, or on Fox Island, Washington. Fox Island premises data was unavailable for intervals shorter than

1 day, so it is understandable that impacts from relatively short events could not be observed. Idaho Falls Power had subdivided its 200 water heater locations into four groups that were sequentially engaged from hour to hour during events; this process diminished the net per-premises impact and made it harder to observe the impact.

Smart appliance suite. Flathead Electric Cooperative and NorthWestern Energy demonstrated suites of residential smart appliances, including thermostats, water heater controllers, IHDs, and even plug-load switches. The project reviewed the impacts from the suite as a whole based on premises-level metering. The Flathead Electric suite achieved reduction of 170 W per premises during events, on average, for the 118 members who received the suite.

Dynamic voltage management. Two of the PNWSGD utilities reduced feeder voltages to conserve energy during short-term (hours-long) events. While the infrastructure needed to conduct dynamic voltage control is similar to that used in conventional conservation voltage reduction, the purpose of conservation voltage reduction is long-term conservation, not short-term demand responses. No impact could be confirmed on Fox Island. Surprisingly, consumption appeared to *increase* in Milton-Freewater for these short events. Analysts hope to review this surprising preliminary finding as time permits.

Melding some of the best features of dynamic voltage management and DRUs, Milton-Freewater demonstrated grid-friendly, voltage-responsive water heater controllers. These water heater controllers were reliably engaged by feeder voltage reductions and achieved impacts comparable to systems that had required communications to DRUs.

Battery systems. The PNWSGD demonstrated battery energy storage systems at four of its utilities. The largest battery system was the Salem, Oregon, 5 MW, 1.25 MWh system. The project received test data from Portland General Electric that confirmed the capacity and capability of this battery system. Two utilities installed skid-mounted systems, but the systems' vendor ran into financial difficulties before these units' performance could be confirmed. The utilities and their remaining vendors limited their battery systems' responses to no more than one full charge cycle per day.

Distributed generators. Six distributed steam and diesel generators were controllable by the PNWSGD—three at each of the WSU and UW campuses. The distributed generators largely remained under the direct control of human operators at the two universities. The UW generators' operator normally checked the status of the transactive signals once per day in the morning to decide if they needed to change their generation schedule. WSU established a handshake mechanism with Avista Utilities with which the utility could request and the university could confirm their generators' responses.

The PNWSGD demonstrated most of the classes of responsive assets that are commercially available today. Utilities observed that the communications of the systems were not especially interoperable out of the box. Additional engineering integration was required. Many loads are still made controllable in a smart grid by "tacking on" the control system to existing electric loads. The devices are not yet smart enough to cleverly manage the tradeoffs between customer comfort and the grid's needs. The controllability is usually limited to switching the load off. There are very few assets that can *increase* load or smoothly transition throughout a continuum of available responses. Finally, the largest controllable loads maintain human control, which often limits the availability and reliability of the assets' responses.

A key to the successful application of transactive systems is the use of automation to coordinate the decision making and action of the responsive assets. Research and development is needed to further develop and deploy distributed, automated systems, both within the utility infrastructure and in customer premises. The performance of the automated systems must be demonstrated to be at a high enough level that utilities and their customers are comfortable with the results. Otherwise, there will continue to be significant use of person-in-the-loop approaches that limit the effectiveness of the technologies in delivering full value to the asset owner and the electric power system.

Research is also needed into the policy dimensions of incentivizing customers to respond to a dynamic cost or price signal. The PNWSGD transactive incentive signal is a dynamic representation of cost, but it was not used in a tariff. The participating utilities were asked to respond, and to have asset systems, generally involving their customers, provide the response. For large scale deployment, there is still work to be done on whether to use the dynamic cost signals as a dynamic tariff, or whether an approach based on periodic compensation, such as monthly capacity payments for which customers agree to respond to the dynamic signal, is better.