16.0 Portland General Electric Site Tests

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Portland General Electric is a vertically integrated, investor-owned utility that serves much of Portland, Oregon, and areas south, including its project site in Salem, Oregon. It is Oregon's largest utility, serving 843 thousand customers, of which 100 thousand are commercial customers. The utility owns a diverse mix of generation resources including thermal, natural gas, hydropower, and renewables (Portland General Electric 2015).

The utility focused its Pacific Northwest Smart Grid Demonstration (PNWSGD) project participation in Salem, Oregon, and referred to these demonstration activities collectively as their Salem Smart Power Project (SSPP). Portland General Electric was interested in testing and demonstrating many smart grid technologies, but the most ambitious is the large battery energy storage system at its Salem Smart Power Center. The utility had planned to demonstrate the following five asset systems, which are discussed in much greater detail later in this chapter:

- residential demand response (DR) (Section 16.2)
- commercial DR (Section 16.3)
- commercial distributed standby generation (DSG) (Section 16.4)
- battery storage in a high-reliability zone (Section 16.5)
- distribution switching and residential/commercial microgrid (Section 16.6).

The relationships between these components of the SSPP and the Salem distribution grid are shown in Figure 16.1. The PNWSGD used this layout diagram to suggest how the various assets could affect the site's distribution system and how system impacts might be metered for verification. Table 16.1 provides a key to the naming convention that was used for the data in Figure 16.1. Text in Figure 16.1 such as "(-,C,C,C,C)" and "(-,E,E,E,E)" is a nominal description of whether the data is a member of the control (i.e., "C") or experimental ("E") groups in the ordered list of asset systems. Asset PG-01, concerning residential DR, was removed from the layout diagram. Few willing residential customers were recruited, and the effort was abandoned when its risks exceeded the value of continuing.

Table 16.1. Key to Data Stream Names Used in Figure 16.1

Data Stream Name	Description
PG-IM-1-*	Customer meter power
PG-IM-41-*	Feeder real power
PG-IM-42-*	Feeder reactive power
PG-IM-60-1	System Average Interruption Frequency Index
PG-IM-62-1	Momentary Average Interruption Frequency Index
PG-IM-64-1	Distribution reliability incidents
PG-IM-68-1	Momentary Average Interruption Frequency Index time threshold
PG-IM-151-1	Energy stored in the battery

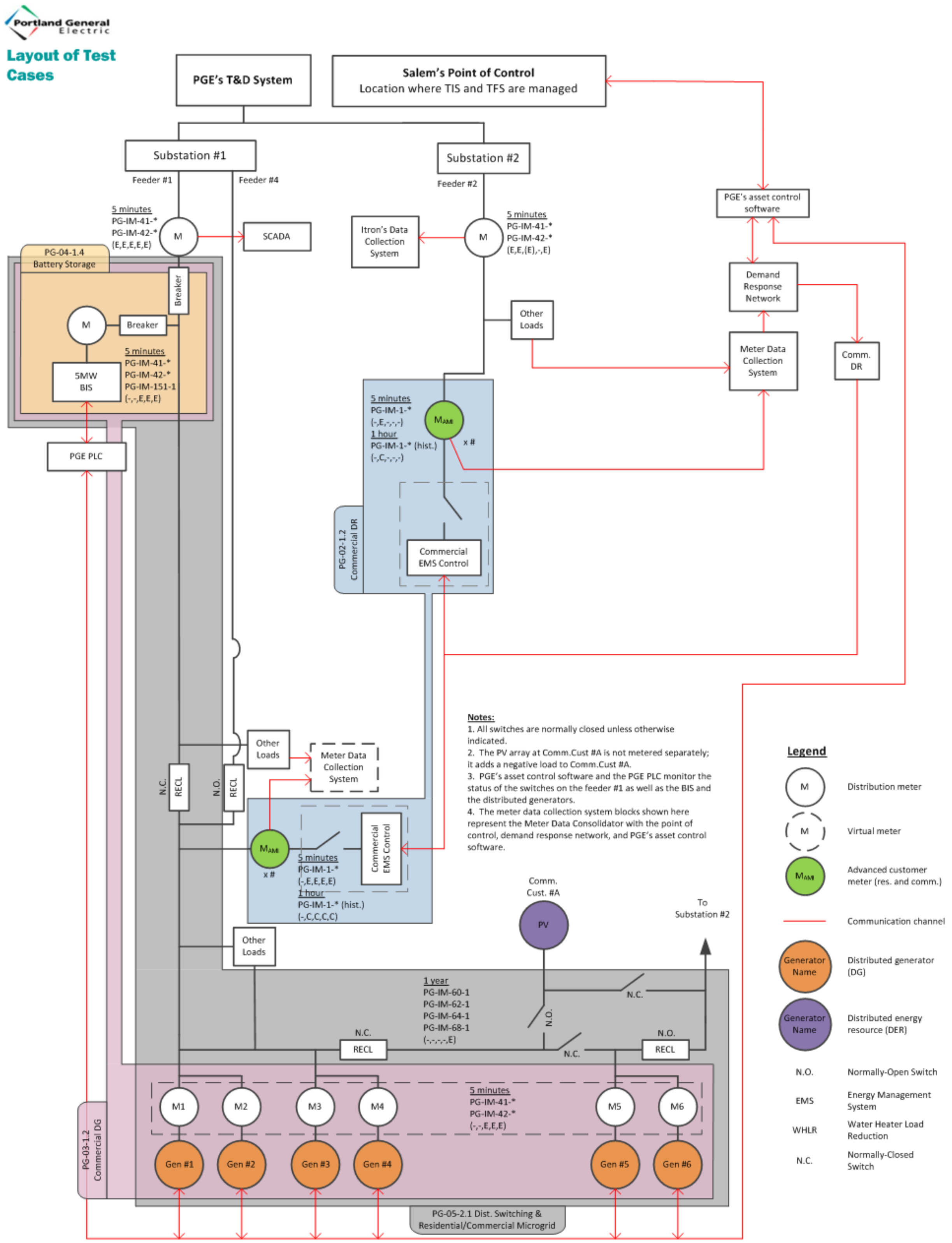

Figure 16.1. Layout of the Portland General Electric Asset Systems on Their South Salem, Oregon, Distribution Circuit

16.1 Portland General Electric's Utility Economic Dispatch Function

The PNWSGD project featured a transactive system (Chapter 2). Portland General Electric reported that its transactive system received and used the transactive incentive signal (TIS) that it received from the Western Oregon transmission zone (TZ05) of the transmission system as it made decisions as to when and how long to dispatch its asset systems, including its battery system.

Portland General Electric developed and implemented its own toolkit functions to dispatch its project resources and DR assets using the TIS that it received from the transactive system and other available information. Portland General Electric's toolkit functions were enacted by a neural network that was trained to recognize opportunity for dispatch based upon a comparison of the incoming TIS and a threshold cost that was tailored uniquely for each of its transactive assets, while constrained by battery- or feeder-specific operational parameters and other asset parameters.[1]

The economic dispatch function seeks to optimize cost over time while, in the case of the battery, also seeking to increase the value of discharge cycles. This function should generally charge the battery in off-peak times and discharge it at peak times, presuming price maxima correlate well with load maxima.[2]

Portland General Electric set operational constraints on the system and enforced these through the automated dispatch function. The battery may not be charged or discharged for less than one full cycle, between 20% and 80% state of charge. This range corresponds to approximately two hours of use per 24-hour calendar period, including one charge and one discharge. This behavior notably corresponds to the battery toolkit function designed by the project[3] that was generally enacted in an IBM Internet-scale Control System-configured node.[4]

The project received no information from the utility about the other conditions that might have affected the dispatch decisions made by Portland General Electric's transactive system and its artificial intelligence (Figure 16.2). Project analysts desired more insights into system control at this site, but it is an intentional design feature of a transactive system that the abundance and availability of power may be communicated without revealing proprietary information throughout the system.

Further conceptual and technical details about this artificial intelligence system and its implementation may be found in (Chandler and Hughes 2013a) and (Chandler and Hughes 2013b).

[1] K Whitener, C Mills, A Ross, B Barney, C Steeprow, D Brown, D Garcia, J Ross, W Lei, B Campbell, V Bhavaraju, A Wick, B Stoick, C Hartzog, T Hans, J Istre, and B Watts (Whitener et al.). April 8, 2014. Salem Smart Power Project Microgrid Aspects. Joint report by Portland General Electric, Eaton, and EnerDel. Portland General Electric, Portland, Oregon, April 8, 2014 (unpublished).
[2] Ibid.
[3] In the project's naming practice, this was "TKLD_4.1."
[4] Whitener et al. 2014 (unpublished).

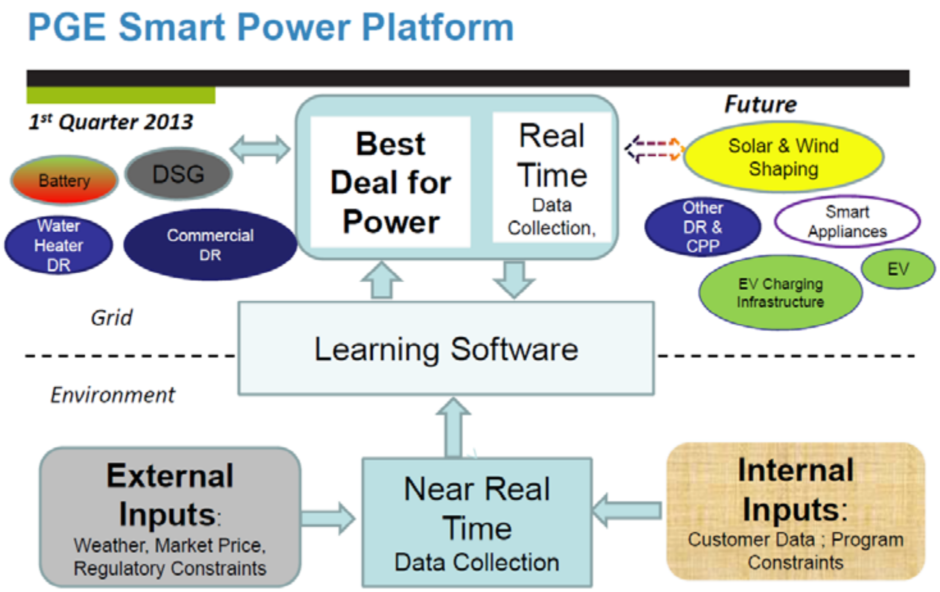

Figure 16.2. Artificial Intelligence was Incorporated into the Smart Power Platform that Engaged the Project's Transactive Assets (from Portland General Electric March 2014, p. 20)[1]

16.2 Residential DR

Portland General Electric had intended to offer residential DR technologies, including water heater timers, air conditioner controls, home energy management systems and/or energy management displays, to qualifying residential households within the site boundary. The objective of the utility's residential DR 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 system was to be responsive to advice from the transactive system.

This activity had already begun by the beginning of the PNWSGD. The utility did not request any project funding for the residential DR devices, but they used demonstration funding to engage the vendor Utility Integration Solutions, Inc. for data management services and for the development of software that would be used to monitor or control the DR measures.

After considerable recruitment efforts, Portland General Electric was able to identify 20 suitable customers for this program. Only two of these premises became observable to the project through data collection. The Rural test feeder definition necessarily changed in 2013 to safely accommodate testing of the utility's battery system, which redefinition limited the observability of the premises data. The program was terminated in October 2013 after an installed load-control device malfunctioned at a residential customer's house.[2] No useful data were received by the project concerning the performance of the residential DR devices.

[1] "EV" is an abbreviation for "electric vehicle," and "CPP" is "critical peak pricing."
[2] Reported by the utility to Battelle in an e-mail dated September 24, 2014.

16.3 Commercial DR

The utility offered DR technologies including building management systems, control relays, and space conditioners to qualifying businesses such as retail and service outlets within the site boundary. The DR assets were made automatically responsive to the utility's transactive system.

Portland General Electric used their commercial DR system to engage commercial loads with customers within the demonstration feeder, thus reducing load when an event was called. Commercial DR control was voluntary, meaning customers could opt not to participate in an event. Based on its historical data and research, the utility accrued a maximum of approximately 25 kW power curtailment from the eight commercial customers on the demonstration feeder. Approximately 1.2 kW of load reduction was expected by the utility during a called event, a curtailment of 5% of the peak load.[1]

Portland General Electric's toolkit function for the control of this asset engaged a neural network that had been trained to recognize opportunity for dispatch based on a comparison of the incoming TIS and the cost-to-go function for the transactive asset. The *cost-to-go* function may be generally described as a function that seeks to optimize cost impacts over time while conforming to all the asset system's constraints. This goal-seeking behavior of the neural network generally implements curtailment events at peak times, providing that price maxima correlate well with load maxima. Responses by the system are constrained by time of year (seasonality), allowed duration of dispatch, time of day, time remaining before the next dispatch, and other parameters. For example, the behavior of the commercial DR system was limited by season and time of day as is shown in Table 16.2.[2]

Table 16.2. Portland General Electric Commercial DR Temporal System Limitations[3]

Constraint Name	Season	Times	Limitation
Seasonal -1	Winter (Dec 1 - Feb 29)	06:00–09:59	Usage approved
		05:00–20:59	Usage approved
		10:00–16:59	Usage restricted
		21:00–05:59	Usage restricted
Seasonal -2	Summer (July 1 - Sep 30)	15:00–19:59	Usage approved
		19:00–14:59	Usage restricted

None of the DR equipment that was placed at commercial sites to provide these DR measures was provided by the project or counted as project cost share. The utility offered the project an opportunity to observe and analyze data from the technology with them and to report about the technology among its final reporting. No demonstration funding was requested from the project for the purchase, installation, or provision of this DR equipment. However, the utility used demonstration funding (or cost share) to engage the vendor Utility Integration Solutions, Inc. for data management services and the development

[1] Whitener et al. 2014 (unpublished).
[2] Ibid.
[3] Ibid.

of software that was used to monitor or control the DR devices. The objective was to test commercial customer acceptance of energy management devices and to measure available load reduction and shifting from the responses.

The annualized costs of the system and its components are listed in Table 16.3. The total system's annualized cost was estimated by the sum of each component's annualized cost, based on the anticipated useful lifetime of the component. Observe that the load-control devices themselves were not included among system costs in this table. The greatest costs were for upgrades to the DR tracking system and the costs of connecting the asset to the Portland General Electric transactive system. Smaller annualized costs were estimated for materials, technical labor, and outreach.

Table 16.3. Annualized Costs of the Commercial DR System and its Components

	Component Allocation (%)	Annualized Component Cost ($K)	Allocated Component Cost ($K)
Utility DR Tracking System	50	375.0	187.5
Transactive Node Development and Equipment	25	109.0	27.2
Materials and Supplies	20	104.4	20.9
Engineering/IT Support	25	7.8	2.0
Outreach and Education	20	6.1	1.2
Total Annualized Asset Cost			**$238.8K**

IT = Information Technology

16.3.1 Characterization of Asset System and Data

Portland General Electric provided the project with premises power data for the eight commercial locations on their demonstration feeder. The project aggregated the data as an average for the eight locations. The data set extends from late September 2012 to early September 2014 and is shown in Figure 16.3. The averaged power magnitude appears similar to that of residences. Upon its review, the utility agreed that the reported average power appeared too small, given the types of commercial sites they believed to have been included. The project reviewed the data it had received and could not find any error that would have caused the power to have been underreported.

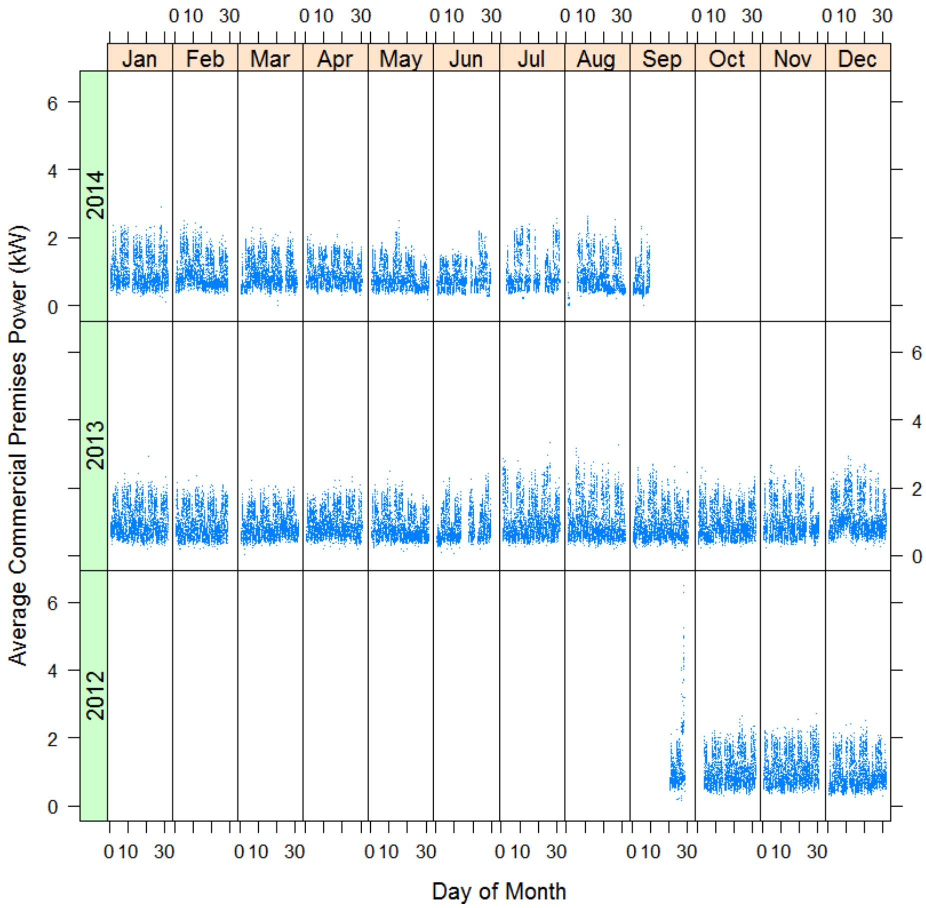

Figure 16.3. Average Power of Commercial Premises

Figure 16.4 shows the average diurnal demand of these eight commercial locations for the four seasons. Unlike residential load, the commercial sites do not exhibit pronounced morning and afternoon peaks. The load is almost symmetrically allocated around noon. There is relatively little difference in the hourly power patterns or magnitudes between the four seasons.

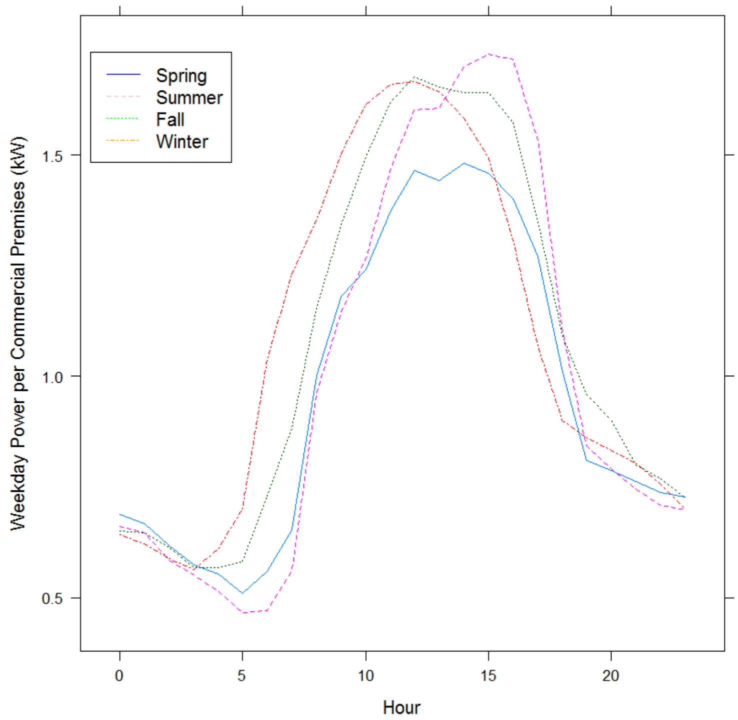

Figure 16.4. Averaged Weekday Diurnal Load Pattern for the Monitored Commercial Premises

The system was declared installed and operational by the end of January 2013. Only three curtailment events were reported by Portland General Electric for the commercial DR system. All three occurred during 2013. The starting times and durations of these events are listed in Table 16.4.

Table 16.4. Three Commercial DR Events that Occurred in 2013

Month	Day	Day of Week	Local Start Time (hh:mm)	Duration (h:mm)
January	31	Thursday	16:00	1:00
July	2	Tuesday	16:00	1:00
December	10	Tuesday	00:00	3:00

16.3.2 Performance of the Commercial DR System

The project generated a regression model of the average commercial premises load. The model was fit to the variables month, weekday, hour, and temperature. The resulting baseline should predict the average power of the commercial premises without DR. Portland General Electric had expected a total reduction of 1.2 kW from the commercial DR system. Based on the three reported events and this regression model baseline, an *increase* in premises power (~200 W) might have occurred during the events. The result was not statistically relevant.

The curtailment was not validated by regression analysis, and it was not evident as a notch by inspection. The system would perhaps need to be engaged more frequently to observe and confidently claim any curtailment benefit.

16.4 Commercial Distributed Standby Generation

Portland General Electric offered to engage 5.7 MW of their DSG system at commercial customer sites within the demonstration feeder, effectively reducing circuit load when an event was called. The utility pioneered engagement of such distributed generation resources via its GenOnSys control system in Portland, Oregon. When called upon via DSG controls, the system was to initiate generation from distributed stationary diesel reciprocating engines at Oregon Military Department, Armed Forces Reserve Center, and Oregon Data Center customer sites.

The DSG system is automated, meaning customers may not opt to cancel an event when called upon by the system; however, the DSG controls group may cancel an event for operational purposes or to meet the requirements of U.S. Environmental Protection Agency regulations governing emergency generation response characteristics. Maximum generation available to the program was approximately 5.7 MW for the three commercial customer DSG sites on the demonstration feeder. Based on the utility's experience with these generators, the response may be fully ramped up within 10 minutes to achieve 100% of the nameplate output.

As for the other responsive assets in this chapter, the responses of the DSG system to the transactive system are enacted by a neural network that has been trained to recognize opportunity for dispatch of the assets based on a comparison of the incoming TIS and the corresponding threshold for the transactive system asset. The algorithm that determines the dynamic threshold seeks to optimize the cost of serving load over time while avoiding asset constraints. This goal-seeking behavior is expected to initiate DSG power generation at peak times, especially when price maxima correlate well with load maxima. The system is constrained by asset parameters including seasonality, permitted minimum and maximum dispatch durations, customer-specific time-of-day limitations, time remaining before the next anticipated dispatch, replacement diesel fuel costs, and other parameters. The DSG assets were prohibited, for example, from operating for less than 1 hour after generation had begun, and the generators must remain inactive for at least an hour before they may be restarted.[1]

Portland General Electric worked with the project to estimate an annualized cost for engaging the distributed generators automatically via the transactive system. The annualized costs of the system and its components are listed in Table 16.5. Observe that the costs of the generators themselves are not included among the system's costs. The starting point of this cost estimate presumes that generators, such as those that exist as backup generators at many commercial and industrial facilities, exist and can be remotely energized. The greatest cost was predicted to be for integration of the generators' controls with the transactive system. Other costs were for materials, backroom communications, and outreach.

[1] Ibid.

Table 16.5. Annualized Costs of the Commercial Distributed Generation System and its Components

	Component Allocation (%)	Annualized Component Cost ($K)	Allocated Component Cost ($K)
Transactive Node Development and Equipment	25	109.0	27.2
Materials and Supplies	20	104.4	20.9
Backroom Server	100	5.0	5.0
Outreach and Education	20	6.1	1.2
Total Annualized Asset Cost			**$54.4K**

On January 30, 2013, the U.S. Environmental Protection Agency finalized amendments to the National Emission Standards for Hazardous Air Pollutants for stationary reciprocating internal combustion engines and the standards of performance for stationary internal combustion engines (78 FR 6674-6724 2013). The ruling allows that for a combined total of 100 hours per year, emergency engines can be used for the following purposes:

- maintenance and testing
- emergency DR for Energy Emergency Alert Level 2 situations
- responding to situations when there is at least a 5% change in voltage
- operating for up to 50 hours to head off potential voltage collapse, or line overloads, that could result in local or regional power disruption.

The net effect of these amendments was that, in the utility's opinion, the contracted generators, which are all diesel fired reciprocating engines, could no longer routinely respond (i.e., be grid-tied) to a pure signal like that from the transactive system that is based on an economic value proposition. After this, the utility investigated ways that generators could demonstrate responsiveness to the transactive system, but without success.

16.4.1 Characterization of Asset System Responses and Data

The project received data from Portland General Electric concerning the power generation from this set of distributed standby generators for a period from June 2011 through early September 2014. The data that was received changed in quality several times during the project, as is shown in Figure 16.5. The utility's definition of the data was uncertain. Some of the uncertainty was caused by the occasional redefinition of the utility's demonstration test circuit. The circuit was occasionally altered to accommodate the development and testing of the utility's 5 MW battery system (Section 16.5). Starting June 2012, the utility decided to submit data only during project transactive events for this asset. The generators are typically required to be tested monthly, but the project received data at a frequency considerably less than monthly.

Based on all the nonzero 2013 and 2014 power data that is shown in Figure 16.5, there have been seven distinct generation levels: 5.4, 3.8, 1.6, 0.82, 0.50, 0.44, and 0.16 MW. Reactive power was also reported during these periods of generation, but the reactive power was more variable and might have been actively managed. The power factor was always 0.94 or better.

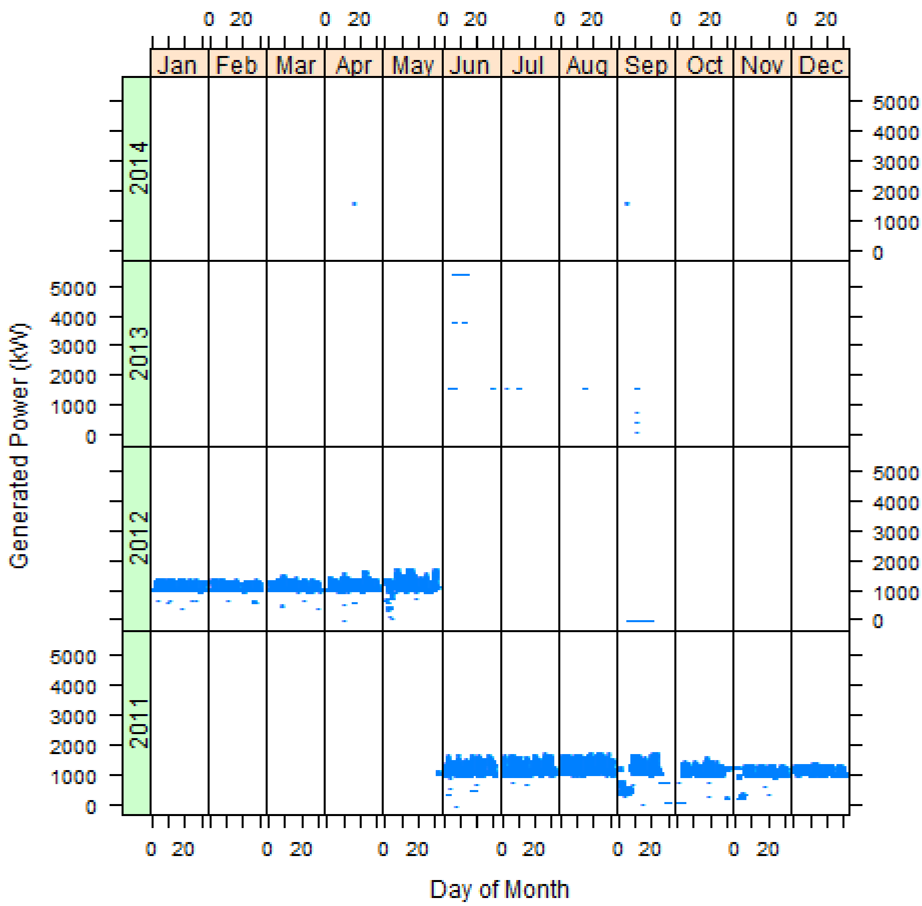

Figure 16.5. Distributed Power Generation Reported to the Project by Portland General Electric

The system was reported to have been installed and useful beginning early April 2013, based on the moment that its reported system status changed from "early unknown" to "off." Figure 16.5 shows power generation during the summer of 2013, but these were not reported by the utility to have been events. The utility reported only one test event to the project for a short 10-minute period, 14:55–15:05 April 16, 2014, when the generators were reported to generate 1.6 MW.

16.4.2 Performance of the Distributed Generator System

From the project's perspective, the received data demonstrates perhaps a discrete set of power generation magnitudes that might be engaged by the DSG system, but the project cannot independently conclude anything about the demonstrated benefits from the operation of the asset. The system was reported to have responded to the transactive system only one time during the project. Nothing can be said about the actual alignment of the asset's operation with any of Portland General Electric's objectives or those of the larger project region. Regardless, this section appends the following hypothetical monetary benefits that were projected for this asset system by Portland General Electric staff.[1]

The differences between the threshold price for engaging DSG assets ($0.288/kWh) and the TIS (~$0.075/kWh) were not sufficient to cause the Portland General Electric transactive system to engage the DSG resources. In the present system, the delivered cost of electricity would need to be artificially elevated above $0.288/kWh to have engaged the generators. That was not done.[2]

Using the approximate frequency of the most expensive wholesale hours each year at the interconnect between the utility and the Western Electricity Coordinating Council (WECC) region as projected by Portland General Electric staff and reproduced in Table 16.6, the WECC energy cost would exceed the threshold price ($0.288/kWh) and would cause the DSG system to generate nine hours in a typical year. If all the generators were to generate during these hours, the benefit each hour would be the product of the generated energy (5.7 MWh) and the price differential between the wholesale price and the threshold target price that hour. The tenth hour wholesale cost would be less than the threshold target, and the generators would not be operated. The differential and cumulative monetary benefits have been calculated in Table 16.6 for each wholesale price. The total annual value of the energy generated these nine hours would be $3,200.[3]

Table 16.6 is hypothetical. It presumes a WECC price cap of $0.45/kWh and further presumes that the hourly price distribution declines exponentially.

Table 16.6. Approximate Distribution of the Highest Hourly WECC Interconnect Prices per Year and Value of Energy Generated these Hours[4]

Wholesale Energy Price this Hour($/kWh)	Number of Hours at this Price	Differential Value of Generated Energy ($K)	Cumulative Value of Generated Energy ($K)
0.45	1	0.9	0.9
0.40	2	1.3	2.2
0.35	2	0.7	2.9
0.30	4	0.3	3.2
0.25	8	−1.7	-

Based on Table 4-4, “Small Commercial and Industrial Customers US 2008$ Summary of the Cost of a 1-Hour Interruption,” in Sullivan et al. (2009), the cost of a 1-hour electricity service interruption to small commercial customer in the Western United States is $886. Portland General Electric hypothesizes that its 110 commercial and industrial customers might avoid one such outage each year through the coordinated responses of its DSG and battery systems. Consequently, the value of these systems toward reduction of commercial customer outages is over $97,500. The battery system responds quickly so that

[1] Ibid.
[2] Ibid.
[3] Ibid.
[4] Ibid.

the DSG system generators can pick up their load after about 10 minutes. The utility therefore suggests that $81,200 of this benefit (about five-sixths, or 84%) should be allocated to the DSG system.[1]

Using similar logic, Table 5-4 of Sullivan et al. (2009) states that the cost of a 1-hour outage for a residential customer in the Western United States is $3.70 (2008 dollars). Forty residential customers are served by the demonstration feeder and might avoid one outage per year due to the DSG system. Therefore, the sum monetary benefit to residential customers due to reduced outages might be $150 per year.[2]

According to Portland General Electric's assessments, the DSG system benefits might be on the order of $85,250 for improved customer reliability and avoided energy costs.[3]

16.5 Battery Storage in High-Reliability Zone

A 5 MW, 1.25 MWh lithium-ion battery energy storage system with custom grid-tied inverters was constructed by Portland General Electric in Salem, Oregon. The system is housed at the utility's new 8,000-square-foot Salem Smart Power Center. The battery system supplier was EnerDel™, and the converter manufacturer was Eaton Corporation. One of the 40 battery racks is shown in Figure 16.6, and the inverter system is shown installed at the Salem Smart Power Center in Figure 16.7.

Figure 16.6. One of 20 Modular Battery System Racks at the Salem Smart Power Center[4]

[1] Ibid.
[2] Ibid.
[3] Ibid.
[4] Ibid, p. 25.

Figure 16.7. Eaton Inverters and Isolation Transformer at the Salem Smart Power Center[1]

The battery and inverter system is useful for both this asset system and the high-reliability-zone microgrid that will be described in Section 16.6. This section addresses the dispatch of the battery system for economic purposes using the utility's economic dispatch function, and the next section addresses distribution automation and the application of battery storage to a microgrid.

Vendor specifications limited the operating region of the battery storage to between 20 and 80% of its full energy capacity. However, system testing by the utility and its team suggested the battery capacity had been significantly overdesigned. Therefore, a smaller fraction of the battery energy capacity, perhaps 35–65%, might be used to further increase battery life while still adhering to the vendor's specifications. Based on the projected number of full lifetime charge cycles, the utility foresees cycling the system no more than about 300 times per year.[2]

The battery's control objectives were to reduce peak demand, avoid or reduce durations of service outages for the commercial customers on the demonstration feeder, to move system load away from the costliest WECC supply hours, to mitigate intermittent renewable energy generation, and to otherwise conduct arbitrage using the costs that were revealed by the utility's transactive system.

While 500 kWh of the energy was reserved for maintaining exceptional service reliability in a high-reliability zone that includes their Oxford substation and Rural feeder in south Salem, Oregon, the remaining storage capacity was available for other operational objectives. Portland General Electric carefully evaluated 20 distinct grid services that are available from battery systems according to a California Public Utilities Commission report (CPUC 2012, p. 13). This evaluation and its findings were documented by Osborn et al. (2013). The conclusions were that

- No regulatory barriers prevent the utility from immediately implementing services that have to do with support and dispatchability of renewable energy resources.

[1] Ibid, p. 25.
[2] Ibid.

- The battery system cannot be said to have deferred upgrades or alleviated transmission constraints at its location on the grid, but it might be used to arbitrage the super-peak periods that occur no more than several times per year. Daily arbitrage would not likely be economical because it could reduce system lifetime.
- The battery was not applicable to demand-side management scenarios because it is not located behind a retail meter.
- The battery may economically serve as spinning reserve and supply other ancillary services, but some of the foreseen ancillary services await new markets and regulatory changes.

Portland General Electric developed its own transactive node to economically dispatch its project resources, including this battery system. The dispatch of these systems was automated using a neural network software tool—the *utility economic dispatch function.*

The annualized costs of the battery system and its components are listed in Table 16.7. Of course, the greatest expense went toward purchase and installation of the battery and inverter hardware. Half the cost of the battery and inverter system was allocated to this asset system, which focuses on dispatching the battery for financial purposes, and the other half was allocated to the battery system's facilitation of improved reliability using a microgrid (Section 16.6). The battery and inverter systems required extensive unit and system testing as documented in the development team's test reports.[1] Other significant costs were for the development of the automated transactive system and for materials and supplies.

Table 16.7. Annualized Costs of the Battery Storage System and Its Components

	Component Allocation (%)	Annualized Component Cost ($K)	Allocated Component Cost ($K)
Battery and Inverter System	50	2,138.9	1,069.5
Transactive Node Development and Equipment	25	109.0	27.2
Materials and Supplies	20	104.4	20.9
Engineering/IT Support	25	7.8	2.0
Outreach and Education	20	6.1	1.2
Total Annualized Asset Cost			**$1,120.8K**

16.5.1 Battery Storage Data

Portland General Electric submitted power data for the battery system from July 2013 until the end of data collection after August 2014. Data from earlier than October 2013 were found to have much greater magnitudes than later and were discarded after the project was unsuccessful interpreting or confirming the units of that early data. The remaining power data are shown in Figure 16.8. The utility submitted status

[1] Ibid.

information that described the system as either available or unavailable. In this figure, positive power represents the discharge of energy from the battery system and negative power is charging it.

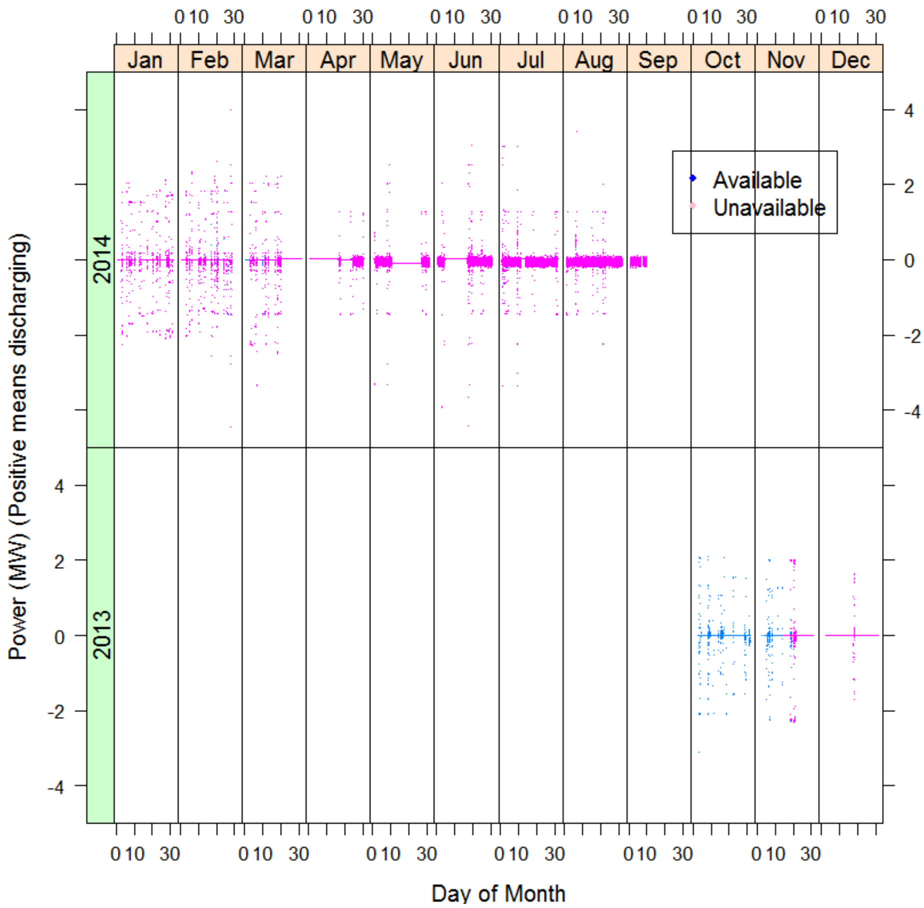

Figure 16.8. Power Discharged from or Charged into the Battery System

It took until spring 2014 before meaningful energy data that reveals the system's state of charge was reported to the project by the utility. The power and energy data are shown in Figure 16.9 for a period between March and August 2014, when both power and energy data were available. The energy data represents the reported total energy state of the battery system that could have theoretically (based on designed system capacity) been 1.25 MWh. The utility asserts that the battery was never discharged to the point that its state of charge was zero. The zero values in Figure 16.9 must therefore be artifacts reported by the system when it became deactivated. The vertical axes ranges in this figure extend to the entire design power and energy capacities of this battery system.

The period of system inactivity in late March 2014 was caused by the failure of the 15 kV pad mount switch that connects the Salem Smart Power Center with the Oxford Rural feeder. It was repaired and the system reactivated in April. The utility and its collaborators do not believe that the failure was caused by operation of the battery system.[1]

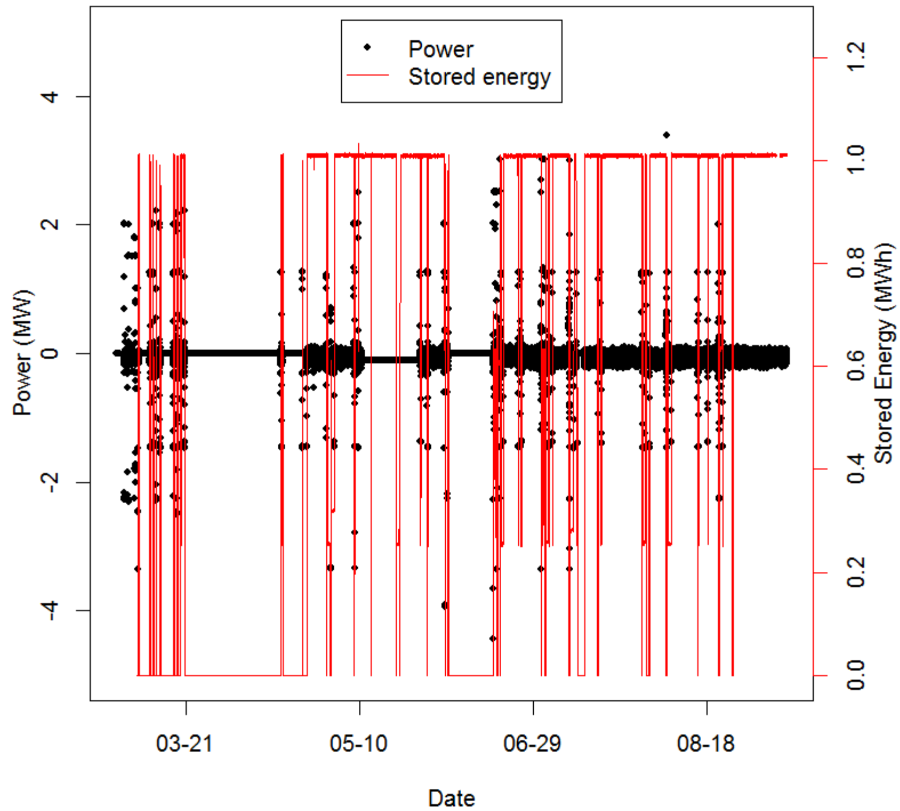

Figure 16.9. Stored Energy and the Charge (negative) or Discharge (positive) Battery Power from Spring and Summer 2014

16.5.2 Performance of the Battery System

The next two figures show narrower time periods for the observation of the battery systems power and energy data. Figure 16.10 shows the energy content and power conversion by the system throughout July 2014. The first day of this month was a Tuesday, so the columns proceed from Tuesday to Monday from left to right. The fifth and sixth columns (i.e., days 5 and 6, etc.) were weekend days. Virtually no testing occurred on weekend days or Mondays. The state of charge increases during charging of the system and decreases during discharging.

[1] Reported in an e-mail from J. Ross of Portland General Electric to S. Kanyid of Battelle dated March 25, 2014.

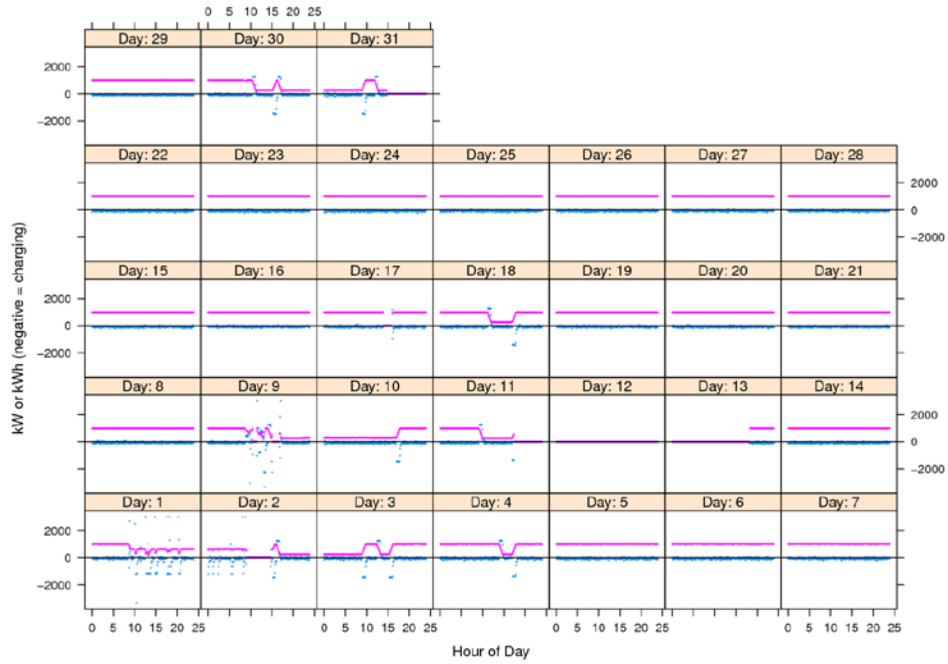

Figure 16.10. Battery Power (blue) and Stored Energy (pink) for Days of July 2014

Figure 16.11 focuses more narrowly on the system's behavior during only three of these days—July 9–11, 2014. The 9th shows much charging and discharging activity. Perhaps a test was being conducted that day to respond to a dynamic signal. The system was recharged the afternoon of the 10th, and cycled again the 11th.

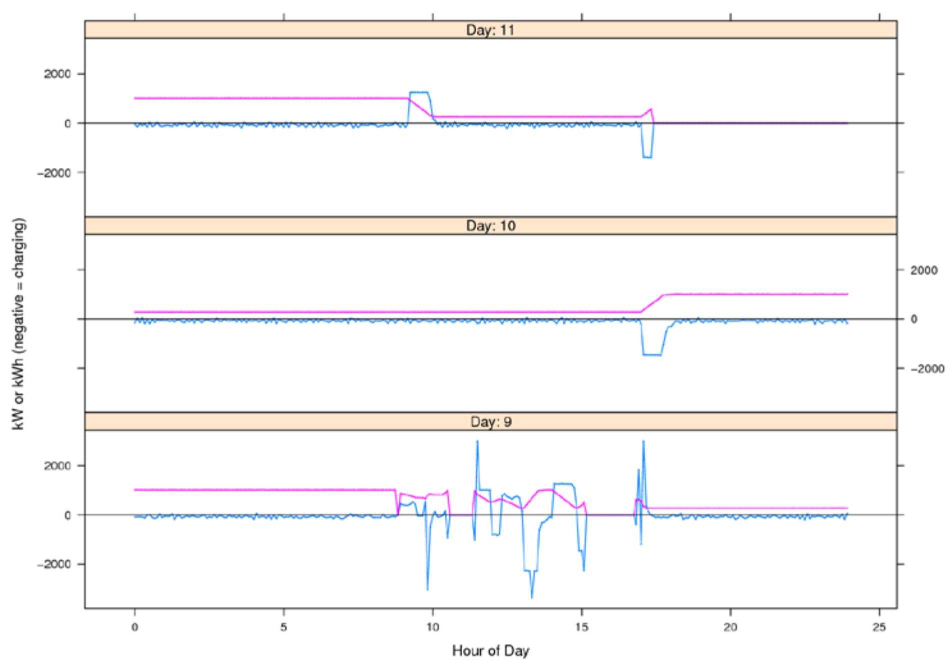

Figure 16.11. Battery Power (blue) and Stored Energy (pink) July 9–11, 2014

In Figure 16.12, the influence of the project's transactive signals on the battery system's charging and discharging is tested. The vertical axis reports the charging (negative) and discharging (positive) battery power. The horizontal axis lists the TISs at these times as received by Portland General Electric from the Western Oregon transmission zone (TZ05) of the project's transactive system. The magnitudes of the transactive signals appear to have had little or no influence on its charging behaviors, regardless of whether the battery system was reported to be available or unavailable to the transactive system. Had the battery system been consistently responsive to the magnitude of the signal that it was receiving from the project's transactive system, power would have been discharged by the battery system at high TIS magnitudes and recharged at relatively lower signal values.

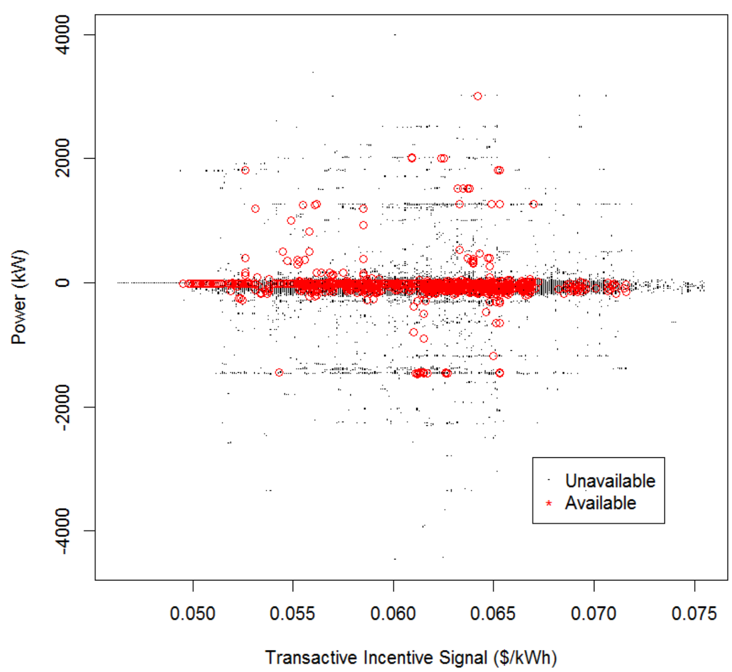

Figure 16.12. Discharge (positive) and Charge (negative) Power as Functions of Transactive Incentive Signal Magnitude and Reported System Availability. Only 2014 data are shown.

Figure 16.13 perhaps reveals an operational strategy used by the utility to charge and discharge the battery system. The height and width of the figure represent the nameplate capabilities of the system. Many of the operating points are located randomly about the center of the power and energy ranges. The state of charge was allowed to vary within a range from about 20 to 80% of the total energy capacity. That is, no operating points were observed below about 0.25 MWh or above about 1.0 MWh. During relatively prolonged charging and discharging, the system was either charged or discharged at the power level 1.25 MW, one-fourth of the system's nameplate capacity. Because this strategy was repeated, we observe a pronounced charge and discharge cycle in the figure. As the target state of charge was approached—often at 20 and 80% of the system's total energy capacity—the charging or discharging rate slowed. The power magnitude decreased until the desired state of charge was achieved.

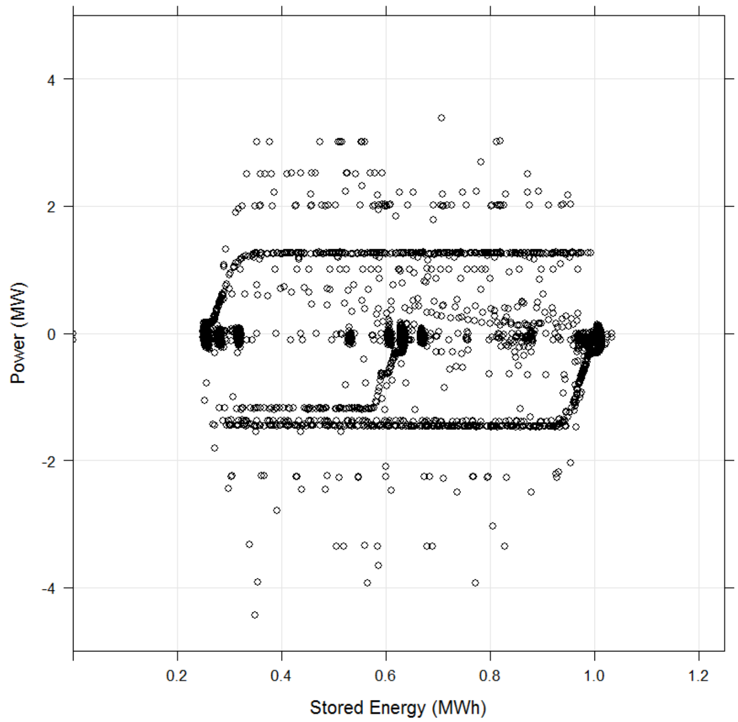

Figure 16.13. Plot of Battery Power versus its State of Charge that Reveals an Operational Strategy

The project investigated the cumulative energy that was reported to have been imported into and generated from the battery system over time in 2014. The resulting Figure 16.14 shows the energy that is lost over this time. The slope of the line changes over time as the operational practices change. If the entire time period is used, altogether 271 MWh were lost over 7,513 hours. The average power loss over this period is 36 kW. This means it takes about 36 kW to keep the battery system operational the way it was used by the utility. This calculation also includes any impacts of conversion inefficiencies during the system's charge and discharge cycles.

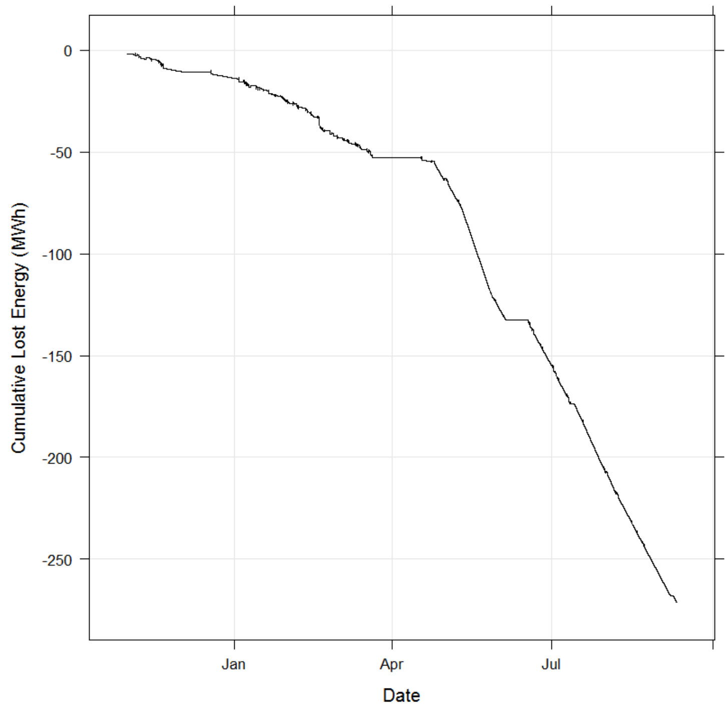

Figure 16.14. Cumulative Energy Exchanged by the Battery System from Late 2013 to the End of the Project

Working with its design team, Portland General Electric monitored the energy that was exchanged during sets of complete charge and discharge cycles. These test results are summarized in Table 16.8. The first row refers to a test in which the system was charged from its 50% state of charge up to its 75% state of charge and back at 25°C and at the target rate 1,250 kW. Because the energy states of charge are returned to their starting levels in each of the four tests, the differences between the amounts of charged and discharged energy may be used to estimate full-cycle efficiency—sometimes called *round trip efficiency*—for these test conditions. The calculated cycle efficiencies ranged from 88.2% to 90.7%.

Table 16.8. Calculated Charge/Discharge Cycle Efficiencies at 25°C and 1,250 kW Charge Rate[1]

Charge/Discharge Cycle (% States of Charge)	Charged Energy (kWh)	Discharged Energy (kWh)	Calculated Charge Cycle Efficiency (%)
50–75–50	536	486	90.7
40–60–40	440	393	89.3
25–5–25	510	450	88.2
25–75–25	1,017	902	88.7

[1] Table PGE-04-4.9-PGE1 in Whitener et al. 2014 (unpublished).

Another interesting finding from the utility's acceptance testing[1] was that the energy storage capacity of the system had been somewhat understated by the battery vendor. The stored energy may be as great as 1.8 MWh, not 1.25 MWh. Consequently, Portland General Electric may be able to narrow its cycle depths and extend the useful life of the system.

Figure 16.15 summarizes the average charging or discharging of the system as a function of time of day local Pacific Time. At least in these, its early days of operation, the battery system was predominantly operated only during daytime. Both the charging and discharging were occurring in daylight hours. Otherwise, there is no clear diurnal pattern yet in the way that Portland General Electric managed the charging and discharging of the battery system.

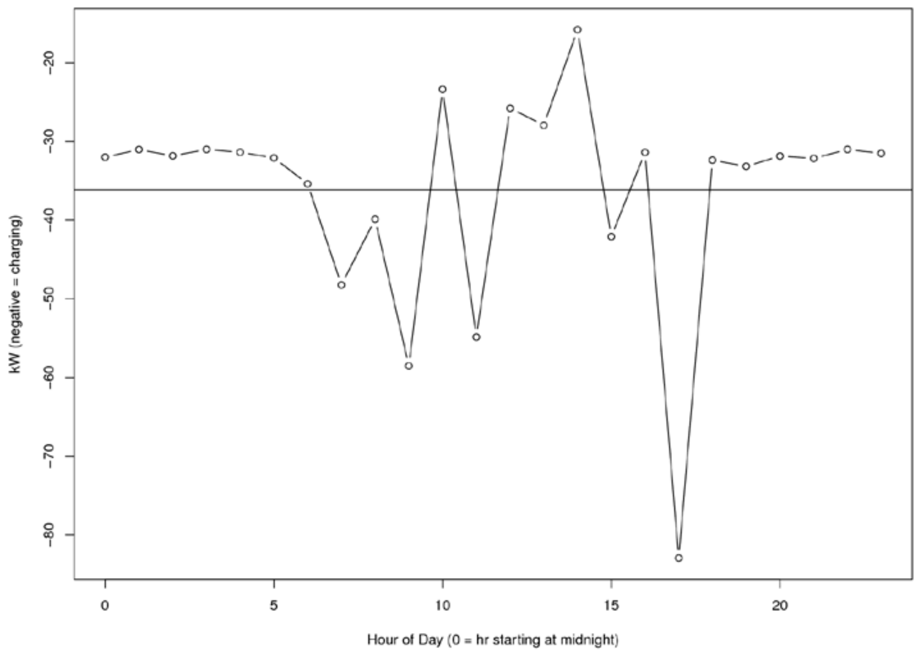

Figure 16.15. Average Charging (negative) and Discharging (positive) Power as a Function of Hour of Day

The following text was paraphrased from unpublished documentation supplied by the utility and could not be confirmed by the project based on data that was delivered to the project by Portland General Electric:

Using the theoretical distribution of daily price differentials in the wholesale price for electricity in the WECC Interconnect, Portland General Electric estimated the monetary benefit available from arbitrage. This distribution and the resulting benefit are presented in Table 16.9. The frequencies of occurrences are presumed to increase exponentially as the price differential diminishes. A presumption is that the system correctly identifies the 300 greatest price differentials each year and fully charges and discharges its nameplate capacity, 1.25 MWh, across this price differential. The system is limited to no

[1] Ibid.

more than these 300 cycles according to vendor specifications. The cumulative yearly benefit estimated for arbitrage is thereby estimated as $9,530 per year.

Table 16.9. Hypothetical Distribution of Differential Wholesale Energy Prices and the Calculated Arbitrage Value that May be Earned using this Differential. This analysis presumes that the full 1.25 MWh is exchanged each charge/discharge cycle.[1]

Energy Price Differential ($/kWh)	Occurrences Per Year	Cumulative Battery System Cycles	Differential Energy Value ($K)	Cumulative Energy Value ($K)
0.09	1	1	0.11	0.11
0.08	2	3	0.20	0.31
0.07	4	7	0.35	0.66
0.06	8	15	0.60	1.26
0.05	16	31	1.00	2.26
0.04	32	63	1.60	3.86
0.03	64	127	2.40	6.26
0.02	128	255	3.20	9.46
0.01	5[(a)]	300[(a)]	0.063	9.53

(a) The cycles have been limited in this row because the battery's vendor specifies only 300 cycles per year for the system.

Based on Table 4-4 in Sullivan et al. (2009), "Small Commercial and Industrial Customers U.S. 2008$ Summary of the Cost of a 1-Hour Interruption," the cost of a 1-hour electricity service interruption to a small commercial customer in the Western United States is $886. If one such outage is avoided by each of 110 commercial customers on the demonstration feeder each year, the cumulative yearly benefit would be about $97,500. The utility projects that this benefit will result from the coordination of the battery system and distributed generators (Section 16.4). The battery, in principle, responds rapidly to the outage until the distributed generators ramp up within 10 minutes. Therefore, only about one-sixth, or $15,600, of this yearly benefit can be allocated to the battery system.

Voltage sag events are valued at $273 per event per commercial customer in the same citation. If each of the 110 commercial customers on the distribution feeder avoids four voltage sag events, the cumulative benefits of the battery system would be about $120 thousand per year.

According to Sullivan et al. (2009), the impact of a 1-hour residential customer outage in the West is $3.70 (2008 dollars) per customer per outage. Averaging over time, with one expected interruption avoided per year (based on historical feeder data for Portland General Electric's demonstration system), and theoretical 40 residential customers, the cumulative benefit of the battery system to residential customers will be about $150 per year.

[1] In an appendix attributed to S Chandler in Whitener et al. 2014 (unpublished).

The same citation valued the cost of voltage sags to residential customers at $2.20 per customer per event. If the theoretical 40 residential customers on the demonstration feeder avoid four voltage sag events per year, the cumulative benefit is about $350 per year. Notably, the time of day strongly influences the results; these results have been averaged for any period.

The sum of all these hypothetical benefits is about $146 thousand per year.

16.6 Distribution Switching and Residential/Commercial Microgrid

Increased reliability and self-healing networks are prominent characteristics of a smart grid. Portland General Electric installed two automated switches and three automated reclosers to allow separation of a microgrid upon a loss of power from their Oxford feeder. During the transient loss of power, the 5 MW battery and inverter system was to provide power until backup generators could be brought on line.

The microgrid assets and interrupter locations have been identified geographically in Figure 16.16 and in block diagram form in Figure 16.17.

Subject to approval from the customers in the area, Portland General Electric was 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. Fiber-based communications were to connect all of the fast-acting devices. Each device was to be programmed with logic to implement a controlled switching sequence based on the extensive modeling and testing conducted prior to implementation on the Salem feeder.

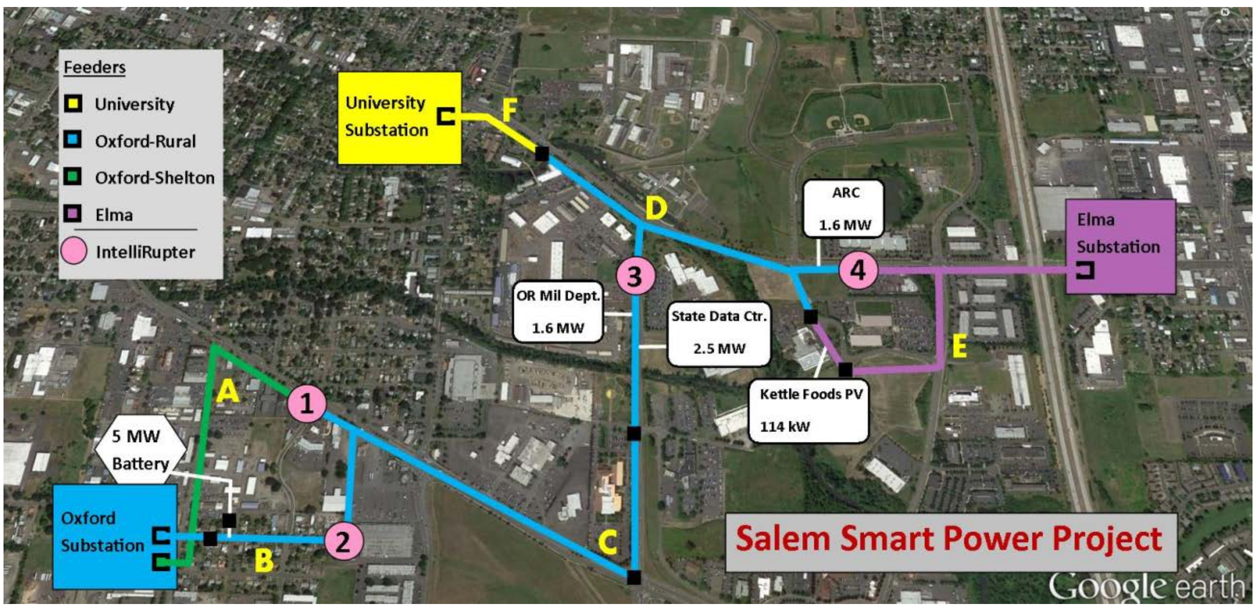

Figure 16.16. Footprint of the Salem Smart Power Project, Salem, Oregon, including its Potential Microgrid Resources and Switches (p.8, Osborn et al., 2013)

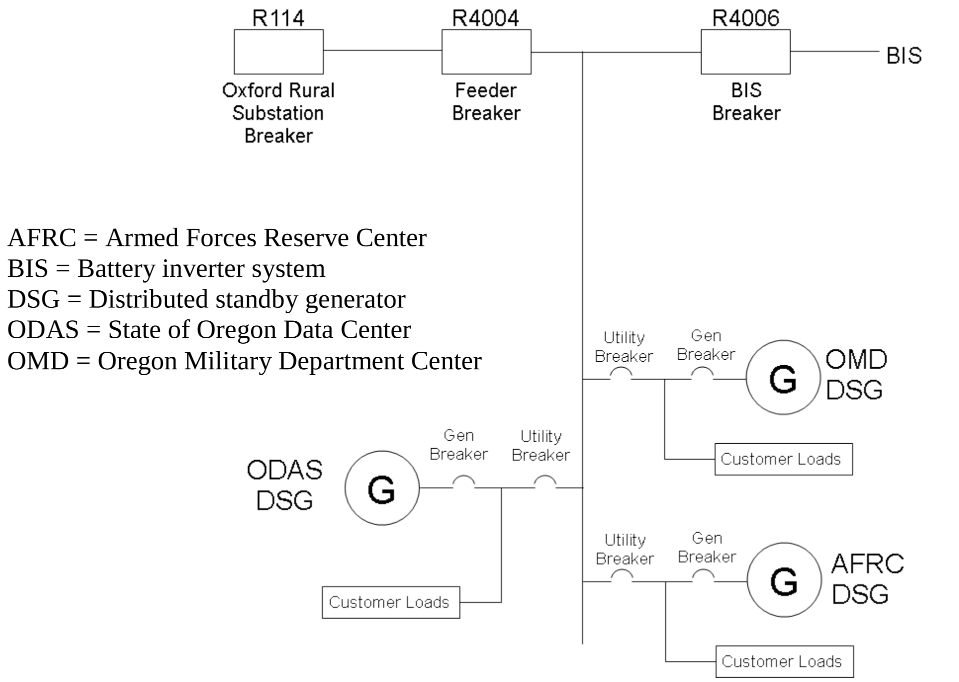

Figure 16.17. Oxford Rural Feeder High-Reliability–Zone Block Diagram[1]

The annualized costs of the system and its components are listed in Table 16.10. The greatest cost component is that of the battery and inverter system. Half of the cost of this system was allocated to this objective (i.e., improved reliability from the definition of a microgrid), and half was allocated to the dispatch of the battery system for economic reasons (Section 16.5). Other significant costs were for automated distribution switches and other materials and supplies.

Table 16.10. Annualized Costs of the Distribution Switching and Microgrid System and its Components

	Component Allocation (%)	Annualized Component Cost ($K)	Allocated Component Cost ($K)
Battery and Inverter System	50	2,138.9	1,069.5
Automated Switch/Recloser	100	45.9	45.9
Materials and Supplies	20	104.4	20.9
Engineering/IT Support	25	7.8	2.0
Outreach and Education	20	6.1	1.2
Total Annualized Asset Cost			**$1,139.4K**

[1] In Whitener et al. 2014 (unpublished).

16.6.1 Performance of the Distribution Automation System

Portland General Electric submitted status information concerning the topological status of the demonstration circuit. The four statuses were “Early Unknown,” “Short,” “Residential,” and “Long.” System activity occurred in late February and March 2014 when the circuit was reported to have transitioned through all the four configurations. Thereafter, the circuit remained in its “Residential” configuration. The utility reported that no events occurred during the project on this feeder. System Average Interruption Duration Index, Momentary Average Interruption Frequency Index, and the count of significant events were all reported to be zero. No change in the reliability of the demonstration circuit was demonstrated.

The utility reported that a series of offline tests had been conducted in preparation for microgrid operation. These tests included individual vaults or racks from the battery system as well as generator and laboratory loads. The high-reliability zone has not yet been operated as a microgrid as of the drafting of this report.

16.7 Lessons Learned and Conclusions

Portland General Electric integrated four smart grid technologies during the PNWSGD—commercial DR, commercial DSG, battery, and distribution switching in a high-reliability zone.

Despite strong efforts, the utility was able to recruit only 20 suitable residential customers on its demonstration feeder to participate in residential water heater DR. Most of these premises were unobservable while the Oxford Rural demonstration feeder remained in a safe, alternative configuration through much of 2013. Furthermore, the water heater load-control devices were removed early when the utility became concerned about potential malfunction due to the safety of these devices.

Demand-response equipment was installed at eight commercial customer locations, but the utility’s economic dispatch function engaged these devices only three times during the project. The annualized cost of this system was estimated at about $239 thousand per year. The project was not able to verify the anticipated change in load at these commercial sites. The project was unable to confirm the power magnitudes at the commercial sites.

The utility invited voluntary engagement of 5.7 MW of distributed standby generator capacity. The annualized cost to set up this system and engage these generators was estimated at $54 thousand. Regulatory hurdles were encountered. The project received data that showed sporadic operation of generators, but the utility’s economic dispatch function never called upon the generators to operate during the project. These generators are unlikely to become engaged for economic purposes. However, the utility allocates value to the system of generators because of its potential to prevent or shorten outages on the demonstration feeder—a high-reliability zone. Thus, no benefit could be directly calculated and monetized by the project, but Portland General Electric projects hypothetical benefits of about $85 thousand per year, most of this attributed to avoidance of outages for its commercial and industrial customers.

A 1.25 MWh battery and inverter system was constructed through a collaboration of the utility with EnerDel and Eaton. The project estimated the annualized costs of this system at $1.12 million. Delays were encountered due to the complexity of the system. The project received data that confirmed operation of the system, but the system's operation could not be correlated with the magnitude of transactive signals or any other input by the project. The utility foresees value of the battery system toward firming renewable energy, arbitrage avoidance of super-peak costs, and reduction of outages in the high-reliability zone. While monetary benefits could not be directly confirmed by the project, Portland General Electric projects hypothetical benefits at about $146 thousand per year, most of this attributable to reduced outages and improved voltage quality for its commercial and industrial customers.

At project conclusion, Portland General Electric's project manager offered the following observations about the lessons the company had learned during the project[1]:

Portland General Electric's SSPP deployed and integrated a substantial battery and inverter system from two separate vendors. This proved a challenge inasmuch as both vendors made concessions and design changes to enable the final outcome of grid integration. The inverter is a "smart inverter" capable of four-quadrant performance. As this was a substantial advance in the use of a large capacity battery and inverter systems, utility staff needed to be educated concerning its capabilities and possibilities.

Frequent changes were made by the project to the integration requirements for the proxy node and data gathering schema for site transactive nodes. As is true of many software projects, the requirements continued to change well past the published "build-to" date of the specifications, which caused significant redesign and redeployment issues. Data gathering was addressed during deployment of Phase 2 of the project, creating significant architecture hurdles for utility site participants. For example, several of the utility's project data streams were initially configured with too-low precision, which caused the data to become erroneously rounded to zero. Testing and integration of assets with longer timelines for completion (the battery-inverter system in particular) caused subsequent delay of control algorithm development and testing.

Vendors were slow to provide proper documentation concerning application programming interface systems integration. Vendors lacked processes to protect utility information. As relatively new players with utility software development, vendors lacked necessary processes and controls. Vendor issues for first-ever systems had long timelines, which delayed progress for transactive node development and integration.

The utility needed to engage the public openly and transparently with clear, concise messages on the SSPP assets, purpose, location, and operations. Support from corporate communications, community affairs and government affairs staff was helpful and critical to success on this front.

System security requirements were well established at the beginning of the project, allowing for completion of the required security tasks without issues or redesign. Proxy-node communication support[2] was weak at the beginning of the project, but the proxy-node implementation was finally recognized as a

[1] Edited from C Mills. 2014. Portland General Electric PNWSGD Lessons Learned. Unpublished report, Portland General Electric, Portland, Oregon, September 18, 2014.

[2] "Proxy-node support" refers to one of two classes of specified point-to-point communication used by the project between the utility sites and the more centralized model of the transmission system. Utilities that did not use IBM's software implementation used a proxy server implementation instead.

separate control domain where reporting for transactive control and other mechanisms were necessary with a separate approach supported by project-level participants. This issue could have been thought through earlier by the project, as was eventually done during deployment.

The utility had to conduct the equivalent of profit and loss accounting at the project level.[1] Historically, utilities mostly just track cost to budget. As the SSPP was innovative and the first of its kind, being an innovator had both advantages and disadvantages. Financially, the utility had to anticipate contingencies:

- When in doubt, overestimate costs.
- Make sure corporate overheads are known by year.
- Confirm property ownership at project beginning and end.

For investor-owned utilities, Table 16.11 summarizes at a high level the opportunities and challenges from the utility's project financial accounting perspective.

Table 16.11. Financial Opportunities and Challenges Faced by Portland General Electric during the Salem Smart Power Project

Opportunity	Challenge
Reimbursable expenses	Unfamiliar accounting needs
Several departments are engaged	Not obvious to rest of company
Excellent funding leverage	Accountable to third party

[1] The U.S. DOE required earned value financial reporting. Some of the complexities of this approach necessarily passed through to utility subcontracts.