7.0 Avista Utilities Site Tests

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Avista Utilities is an investor-owned utility that serves about 680 thousand customers over 30,000 square miles (Avista Corporation 2015). The utility's headquarters are in Spokane, Washington, but it invested in modernization of the Pullman, Washington distribution system during the Pacific Northwest Smart Grid Demonstration (PNWSGD).

The following asset systems were demonstrated at the Pullman, Washington, site. A representation of these tests overlaid on the site's 13 distribution circuits is shown in Figure 7.1.

- volt/VAr optimization (Section 7.1)
- reconductoring (Section 7.2)
- smart, efficient transformers (Section 7.3)
- communicating thermostats (Section 7.4)
- completion of advanced metering infrastructure (Section 7.5)
- fault detection, isolation, and restoration (FDIR) and other reliability enhancements (Section 7.7)
- cooperative control of Washington State University (WSU) facilities
  - heating, ventilation, and air conditioning (HVAC) air handlers (Section 7.8)
  - chiller loops (Section 7.9)
  - diesel generator (Section 7.10)
  - two natural gas generators (Section 7.11)

The performance of these listed systems will be discussed further in the sections of this chapter.

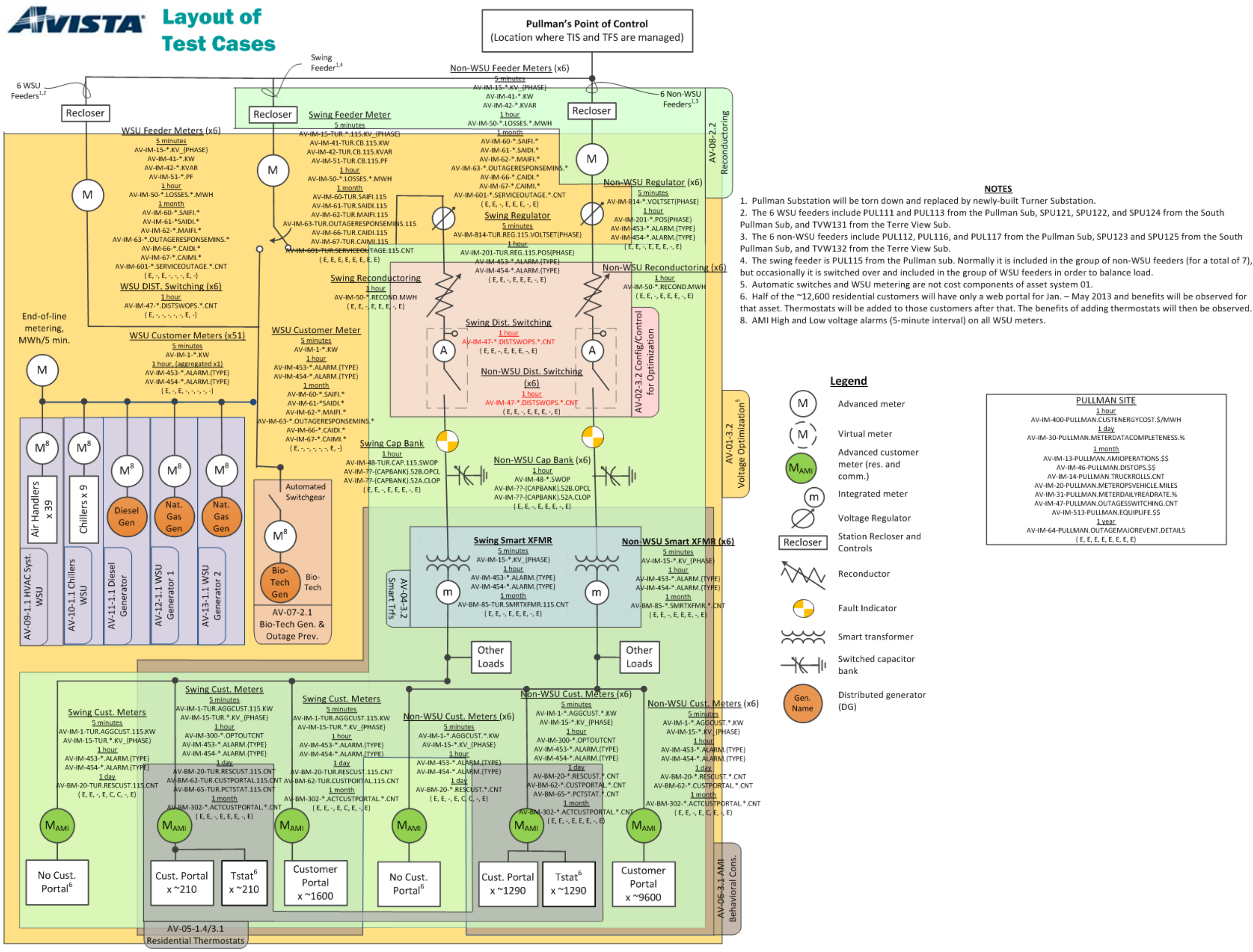


Figure 7.1. Layout of the Avista Utilities Test Groups Overlaid on their Distribution Circuits in Pullman, Washington

Locations within Figure 7.1 refer to data that was expected from the utility for the evaluation of these asset systems that were being demonstrated. The project developed abbreviations for the naming of data series, and most of these abbreviations may be found in Table 7.1. These abbreviations were prepended by “AV-” to indicate that they referenced data from Avista Utilities. The abbreviations were appended by the names of various feeders, substations, customer types, or units of measure to ensure that the names were unique in the project’s databases. The data interval column gives the anticipated time interval represented by a single record from the data stream, and the submit interval was the negotiated time between bulk updates received from Avista Utilities concerning the data stream. The project’s version of this table included many additional columns that specified the relationships between this data and the various asset systems.

Table 7.1. Representative Data Offered by Avista Utilities to the PNWSGD Project. Some of these data-stream naming conventions are found in Figure 7.1.

Data Stream	Data Interval	Submit Interval	Description
BM-20	1 day	1 day	Customer count
BM-62	1 day	1 day	Customer portal count
BM-65	1 day	1 day	Communicating thermostat count
BM-302	1 month	1 month	Active customer portal count
IM-1	5 minutes	1 day	Customer meter real power
IM-13	1 month	1 month	Meter operations cost
IM-14	1 month	1 month	Truck roll count
IM-15	5 min.	1 day	Voltage (phase)
IM-20	1 month	1 month	Meter operations vehicle miles driven
IM-30	1 day	1 month	Customer interval data read
IM-31	1 month	1 month	Customer meter reads by 02:00 daily
IM-41	5 min.	1 day	Distribution meter real power
IM-42	5 min.	1 day	Distribution meter reactive power
IM-46	1 month	1 month	Distribution system operations cost
IM-47	1 hour	1 day	Feeder distribution switching operations
IM-47	1 month	1 month	Distribution outage switch events
IM-48	1 hour	1 day	Capacitor switching count
IM-50	1 hour	1 day	Calculated losses
IM-51	5 min.	1 day	Distribution power factor
IM-60	1 month	1 month	Reliability index - SAIFI (feeder)
IM-61	1 month	1 month	Reliability index - SAIDI (feeder)
IM-62	1 month	1 month	Reliability index - MAIFI (feeder)
IM-63	1 month	1 month	Reliability index - outage response time (feeder)
IM-66	1 month	1 month	Reliability index - CAIDI (feeder)
IM-201	1 hour	1 day	Regulator tap changes
IM-400	1 year	1 year	Description of major system events

Table 7.1. (cont.)

Data Stream	Data Interval	Submit Interval	Description
IM-453	1 hour	1 day	Meter low-voltage alarms
IM-454	1 hour	1 day	Meter high-voltage alarm
IM-601	1 month	1 month	Customer service interruption count (feeder)
IM-622	1 month	1 month	Customer avoided outage minutes
IM-814	5 min.	1 day	Regulator voltage set point

CAIDI = Customer Average Interruption Duration Index
MAIFI = Momentary Average Interruption Frequency Index
SAIDI = System Average Interruption Duration Index
SAIFI = System Average Interruption Frequency Index

A misunderstanding was allowed to persist in Figure 7.1 until quite late in the project. The Pullman, Washington, distribution circuit comprises 13 distribution circuits. Six of these were referred to as “WSU feeders” by utility staff because they supplied the WSU campus in Pullman. Another six “non-WSU feeders” did not. Also, another “swing feeder” could be configured to either supply the campus or not. These terms and this level of understanding were applied in Figure 7.1.

What was not initially understood was that the distribution circuits were not necessarily radial, and the “WSU feeder” circuits may supply both WSU and other customers. A greatly simplified representation of the distribution circuits is shown in Figure 7.2. The project’s analysis was limited by its limited model of the distribution circuit and by its imperfect understanding of the locations of asset systems and their components within the city’s distribution circuit.

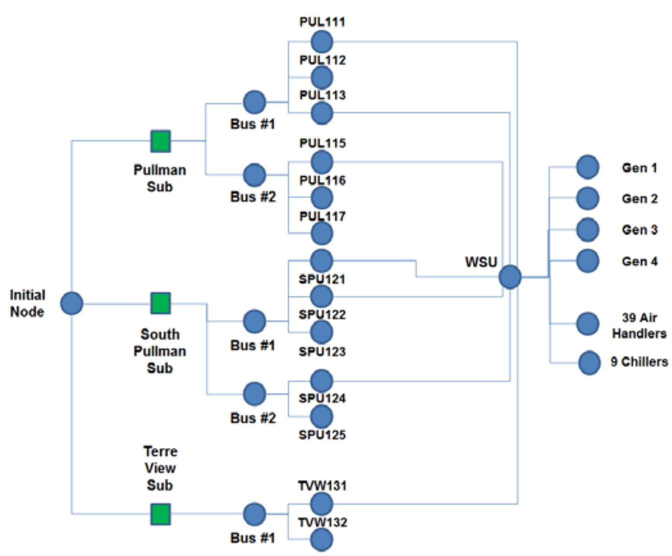


Figure 7.2. Pullman, Washington, Distribution Circuits

Avista Utilities also demonstrated a high level of integration among the demonstrated asset systems during the project, as is demonstrated in Figure 7.3. While the integration of systems is encouraged in a smart grid, the integration made it more difficult for the project to validate the effectiveness of the system's component subsystems. A type of unit testing of the individual subsystems might have better verified their performance apart from the larger integrated system. Particularly in the distribution automation subsystem components (e.g., voltage optimization, configuration control), the software system itself was granted the responsibility by the utility to compile and state its benefits.

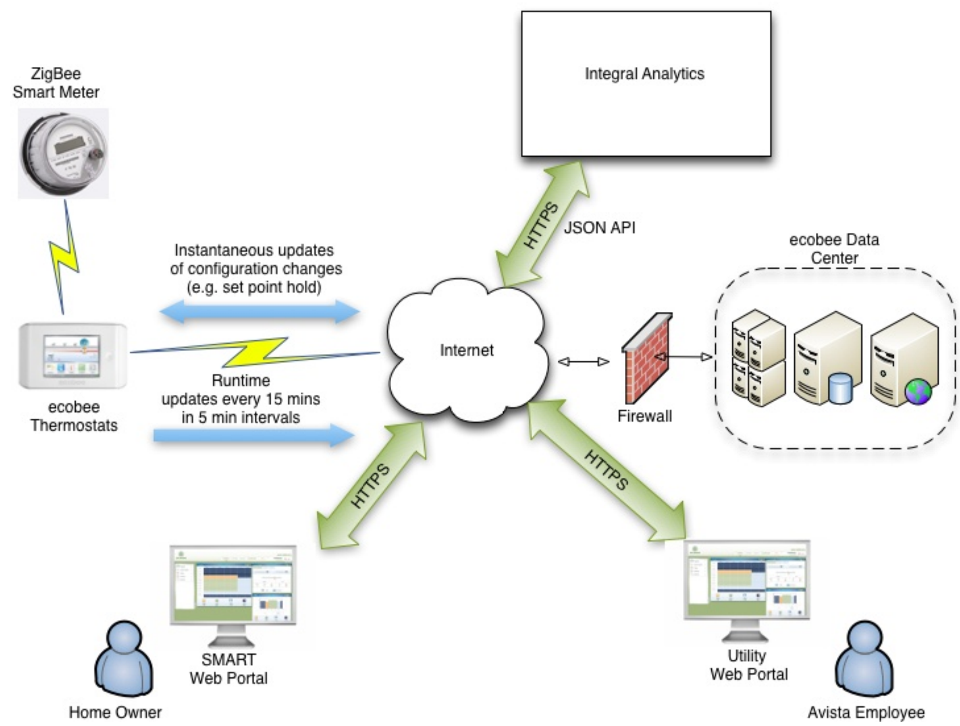


Figure 7.3. The Avista Utilities Customer Equipment (Thermostats), Customer Web Portals, and Distribution Automation Systems were Highly Integrated

7.1 Voltage and Reactive Power Optimization

Avista Utilities installed an integrated volt/VAr[1] control (IVVC) system to optimize voltages and improve power factors in the Pullman, Washington, circuits. It procured and installed Schweitzer Engineering Laboratories (SEL) (SEL 2015) voltage-regulator controllers to control Cooper Industries (Cooper Power Systems 2013) step-voltage–regulator banks on each phase of its 13 feeders. It also controlled the statuses of as many as 60 300 kVAr switched capacitor banks. Advanced Control Systems (ACS) (ACS 2015) customized its predictive voltage management and VAr management applications to provide an integrated solution for use with the utility's ACS distribution management system (DMS) for fully automated reactive power and voltage optimization.

[1] VAr = volt-ampere reactive

The project now believes testing of voltage and reactive power control affected all 13 Pullman, Washington, feeders. An early misunderstanding, evident in Figure 7.1, had caused the project to understand that it affected only the seven feeder circuits that did not supply the WSU campus. However, evidence of voltage and VAr control was found for almost all the feeders.

One purpose of this system was to manage distribution voltages to conserve power while maintaining satisfactory service voltage levels. After lowering distribution system voltage, some electric loads consume less power, often resulting in energy conservation. Voltage regulators respond to DMS requests by stepping the voltage up or down in multiple 1/2% increments. With this new capability, Avista Utilities targeted an average 1.85% (600 kW) power reduction.

Additionally, power factor correction allows the same power to be supplied with less distribution line current, thus reducing resistive line losses. The automation of system capacitors dynamically reduced the reactive power levels that must be supplied through the distribution circuits. It will be shown that the process began with static improvements during 2012. Reactive power supplies were significantly reduced even before the IVVC automation began.

If end-of-line voltages are monitored by the IVVC system, the distribution system may operate quite close to the lower voltage limits without impacting customer service. The advanced metering infrastructure (AMI), provided by Itron (Itron 2015) and the smart transformers, provided by Howard Industries (Howard Industries 2015), supplied the end-of-line voltage measurements for the system. Smart transformers were preferred for the end-of-line voltages because they streamed data every 4–10 seconds, eliminating the need for requests to the AMI collection system, responses from the meter concerning metered voltages, and subsequent retrieval of those responses from the collection system.

The step voltage regulators and capacitor banks were configured to automatically adjust voltage and reactive power in both local and remote manners. In the remote mode, the DMS asserted complete control of the voltage regulators and capacitor banks. In the local mode, which may come about as a result of maintenance testing or loss of communication, the SEL controls operated in a predetermined manner to apply line-drop compensation for voltage management while keeping VAr management static per the last known configuration prior to entering the local-control mode.

The DMS communicates with the step-voltage regulators and capacitor bank controllers using an internet protocol via an 802.11 wireless metropolitan area network (MAN). The DMS uses the utility's fiber optic network backbone to communicate with a bank of remote terminal units (RTUs) that are located in the Spokane, Washington, central office. The majority of the fiber backbone existed prior to the project, except for a 7–15 mile section from the Shawnee substation to the Pullman substation. The 802.11 wireless MAN was newly designed and installed for this project.

Initially, Avista Utilities had intended to further reduce its distribution voltages to minimal acceptable levels when advised to do so by the project's transactive system, thus achieving additional reductions in dynamic load and system loss. Perhaps another 1.85% reduction of average power might have been achieved utilizing the remaining margins of the accepted voltage supply range. Up to 600 kW of dynamic power reduction might have been available for a few hours at a time. This goal was abandoned. Significant delays were encountered by the utility as it tested and confirmed the accuracy of its end-of-line voltage monitoring points. The utility was unable to engineer the transactive response of this system by the time the accuracies had been determined and improved.

The IVVC methodology had to be developed as it was not an available vendor product at the beginning of the PNWSGD. Some automation was achieved during the project. In the future, the IVVC system may be made even more efficient after a history of end-of-line voltages has been collected and analyzed. The system may then know which end-use locations are statistically likely to have low or high voltages in given operating modes. The number of points metered by the system may then be reduced, checking locations less frequently if their voltages never approach high or low limits. Successful use of AMI or smart transformers for volt/VAr optimization may further reduce the cost of deployment for IVVC and facilitate the additional operational voltage margin needed by a transactive system for dynamic demand responses.

Avista Utilities' modernization of the Pullman, Washington, distribution circuits was very integrated. The utility worked with the Port of Whitman (Port of Whitman 2014) to improve its fiber backhaul communications infrastructure. This system also relied on upgrades to the DMS.

The annualized costs of the system and its components are listed in Table 7.2. The greatest costs were allocated to finalize installation of the advanced metering system. The costs of the wireless network and efforts to integrate the system with the project's transactive system were also significant. The total annualized cost was just under $1.5 million.

Table 7.2. Components and Annualized Component Costs of the Avista Utilities IVVC System

System Component	Component Allocation (%)	Allocated Annual Component Cost ($K)	
Advanced Metering System		655.5	
• Software and Systems	25		316.0
• Operations and Maintenance	25		100.3
• Residential Equipment			
o Control Group	33		39.2
o Target Group	33		29.7
o Target Group with DR	25		7.1
• Engineering	25		7.7
• Commercial Equipment			
o Control Group	33		5.2
o Target Group and DR	33		4.3
o Target Group	25		0.7
• Training	25		1.9
DMS Software and Hardware for 700-1000 End Points	25	420.8	
Wireless Network	25	173.2	
Transactive Node System	33	114.4	
Voltage Regulators and Controls	100	76.9	

Table 7.2. (cont.)

System Component	Component Allocation (%)	Allocated Annual Component Cost ($K)
Fiber Network Communications	17	53.4
Smart Transformers with Sensors and Wireless Comms.	25	37.3
Switched Capacitor Bank (with SEL controls) Installation	100	29.7
Evaluation, Measurement and Validation	13	22.8
Project Management Services	13	12.9
Subcontractor – Volt/VAr Software	33	12.7
Reconductor	33	11.8
Total Annualized System Cost		**$1,477.9K**

DR = demand response

7.1.1 System Operation and Data Concerning the Voltage Optimization System

Voltage data was critical to the evaluation of the IVVC system's performance. Figure 7.4 is an example of the quality of distribution voltage data that was provided to the project by Avista Utilities for Turner Feeder 111. For most of the 13 feeders, the utility provided 5-minute voltage measurements for each of the three phases. The data period extended from April 2012 through August 2014. Data quality was good by the end of 2012.

As was its practice, the project divided the distribution voltages by their base distribution voltages, resulting in per-unit representations of the distribution voltages. The project graphically reviewed the raw phase voltages like those shown in Figure 7.4. The individual phases have been offset from one another by 0.04 per unit so that they may be compared without overlap. For all 13 feeders, the individual phase voltages were observed to be similar. Observe that the voltage became actively managed at this feeder starting in late 2013. Even under dynamic voltage management, the phase voltages were found to have been controlled simultaneously, not separately. Therefore, the project felt justified averaging the phase voltages and used these averages for the remaining analysis.

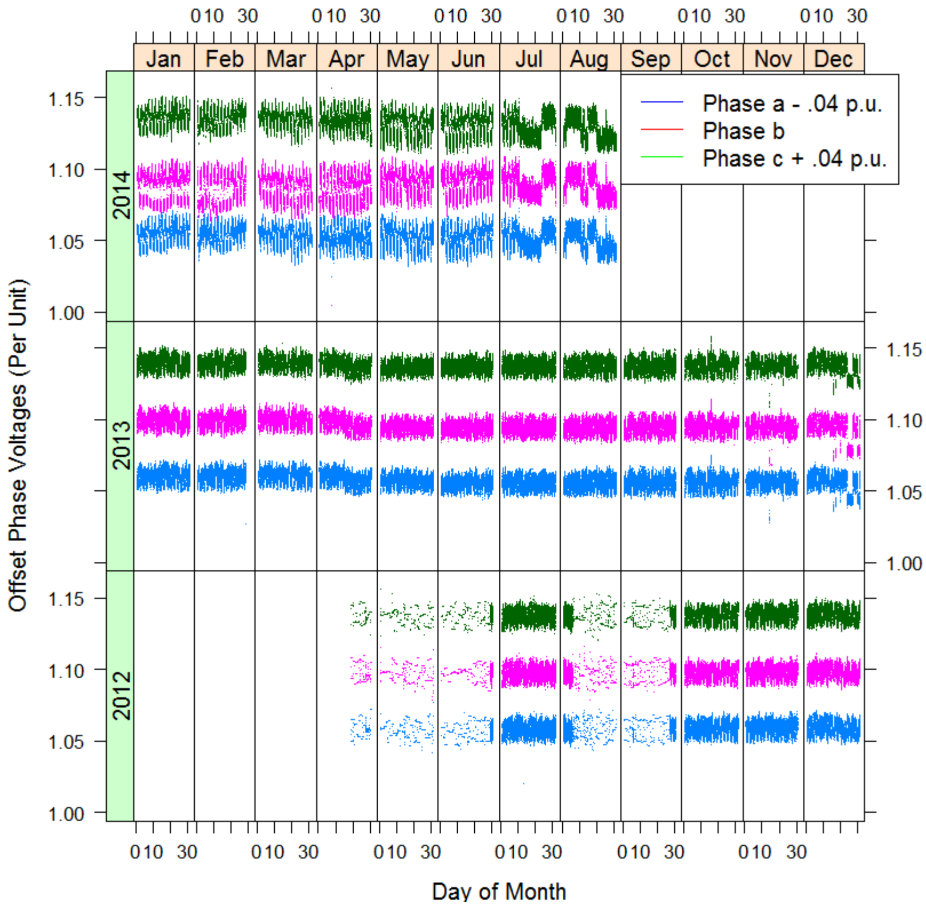


Figure 7.4. Head-End Phase Voltages on Turner Feeder 111

Figure 7.5 shows the same 2014–2014 data as was shown in Figure 7.4 after the individual phase voltages had been averaged. Because the phases were managed identically, the evidence of active voltage management appears to have been preserved. The project found sets of data for each feeder that correlated strongly with the observed voltage levels. For each of the 13 feeders, time series of this type were found to be identical among the three phases.. The status was binary, reporting value “120” when the voltage was at its normal level and value “118” when the voltage had been reduced. The three identical indicator time series were collapsed into a single event indicator for each feeder, stating when voltage management was active and when not. The active (“reduced”) and normal statuses have been shown in Figure 7.5 using red and blue colors. The reported status was very well correlated with the managed voltage level on this feeder.

In the calculation of average feeder voltage, phase voltages below 1.0 per unit were generally discarded as outliers.

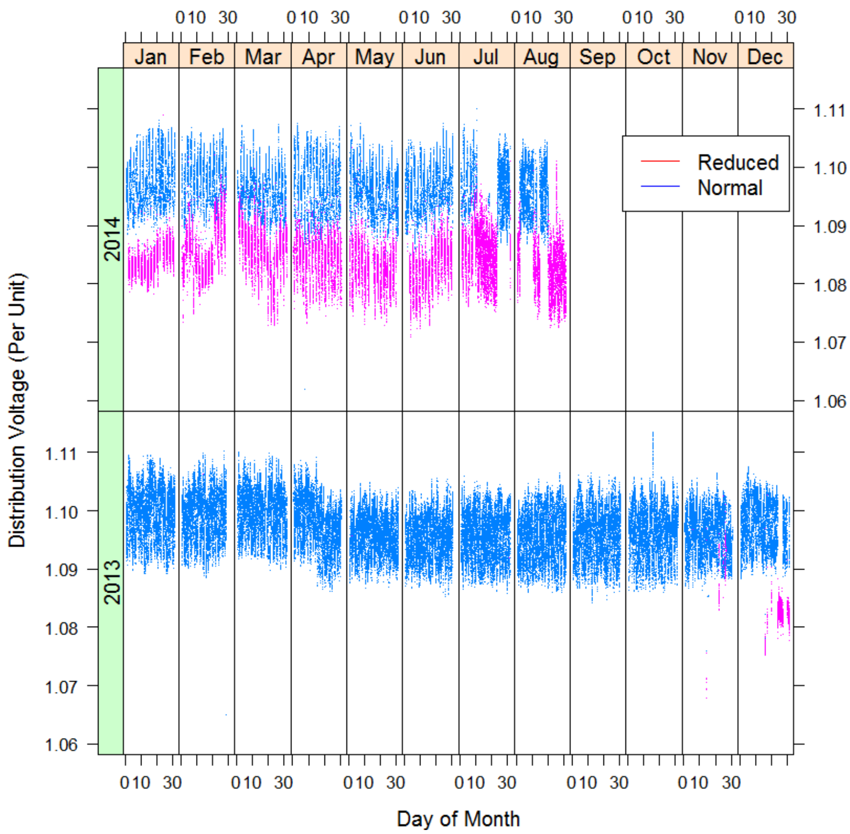


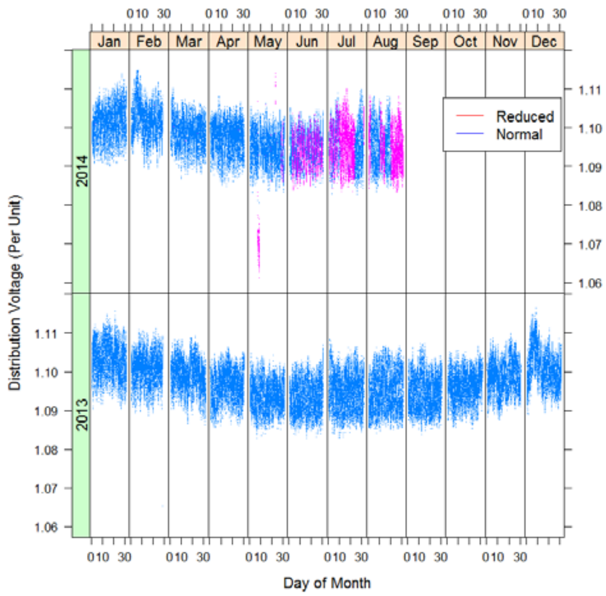
Figure 7.5. Average of Head-End Phase Voltages at Turner Feeder 111. The legend refers to the reported status of the IVVC system, whether it is active (reduced) or normal.

The average head-end distribution circuit voltages of the remaining 12 feeders, marked similarly according to the reported statuses of voltage management on the feeders, are shown in Figure 7.6. Including Turner Feeder 111 from Figure 7.5, nine feeders show clearly that voltage had been substantially reduced and with good correlation to the feeders' reported voltage management indicators.

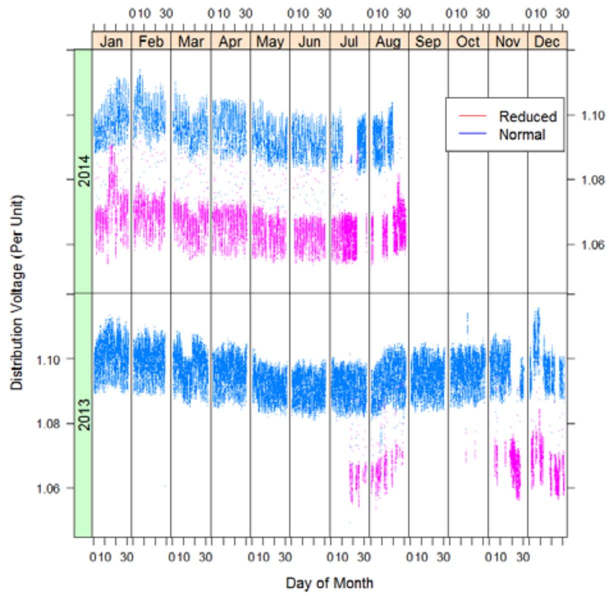
The four feeders with unclear voltage management included Turner Feeders 112 and 115 and South Pullman Feeders 122 and 124. The change in voltage at South Pullman Feeder 125 was greatly reduced for some reason during July and August 2014. The accuracy of the voltage management indicators on the two Terre View feeders was poor prior to April 2014, showing an almost random application of the voltage management status to normal and reduced voltages before then. The voltage management at South Pullman Feeder 122 was actually reversed, showing an *elevated* voltage at times the voltage management system was reported to be active.

Upon reviewing these observations of feeder performance, Avista Utilities responded that they had been challenged by the WSU feeders, which had additional voltage transformations within the WSU campus distribution system. Some of these campus transformers had fixed tap settings, so adjustments to voltage downstream from the Avista delivery point (i.e., the campus meter) were not possible. This resulted in low voltages within the campus that prevented further voltage reduction by the IVVC system.

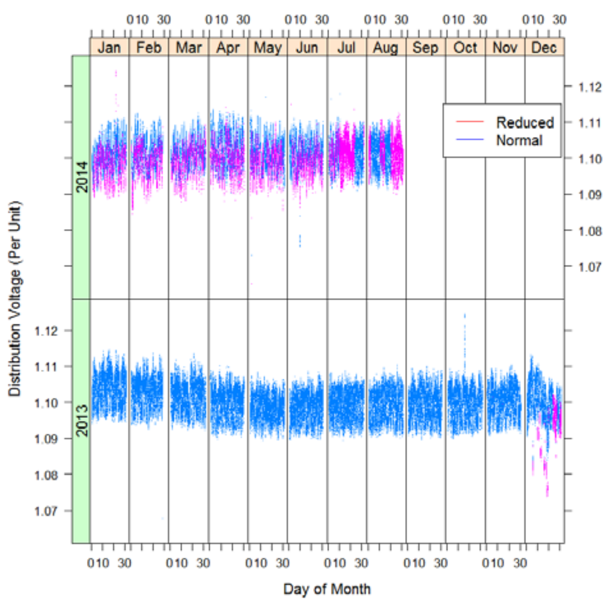
The project had been led to believe that feeders would be managed according to whether they were among the six feeders that serve the WSU campus. That did not appear to be the case. All the feeders were assigned voltage management indicators and all Pullman, Washington feeders were managed by the IVVC system. The feeders that had significant changes in managed voltages included both WSU and non-WSU feeders.



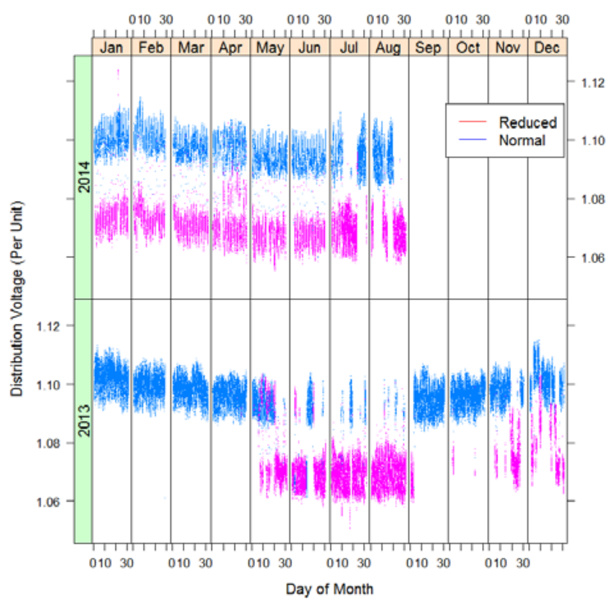
(a) Turner Feeder 112



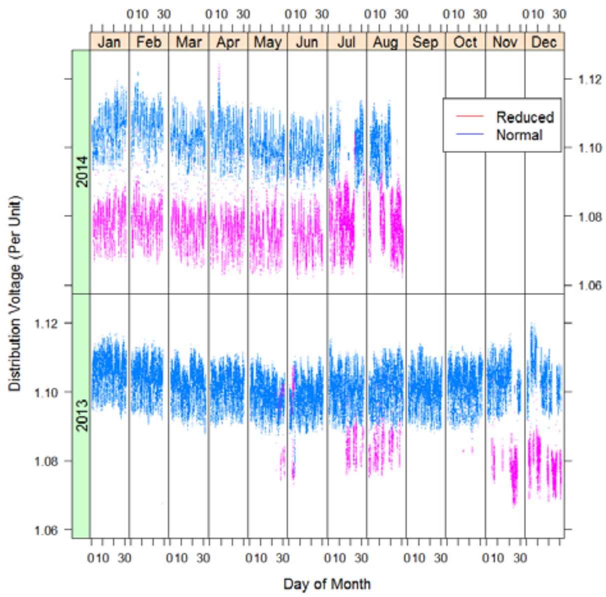
(b) Turner Feeder 113



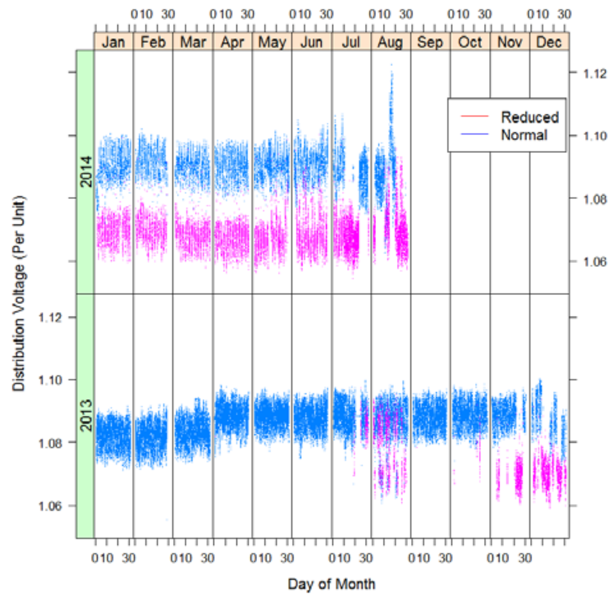
(c) Turner Feeder 115



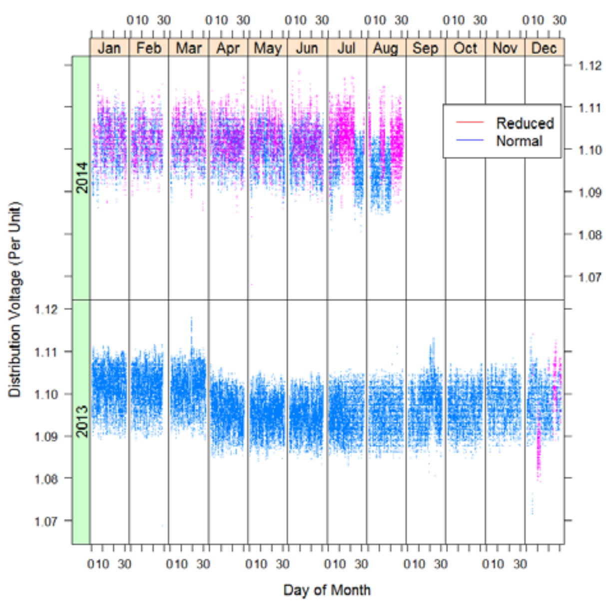
(d) Turner Feeder 116



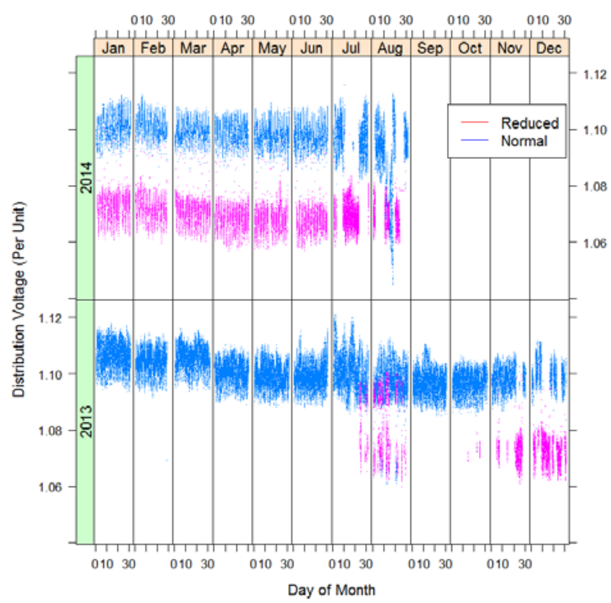
(e) Turner Feeder 117



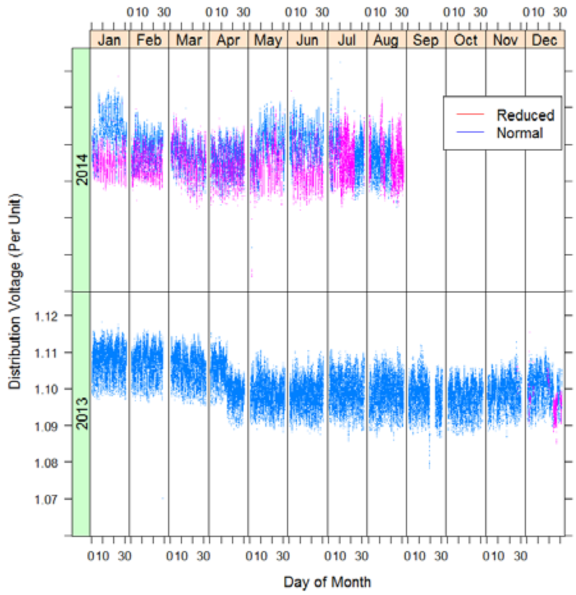
(f) South Pullman Feeder 121



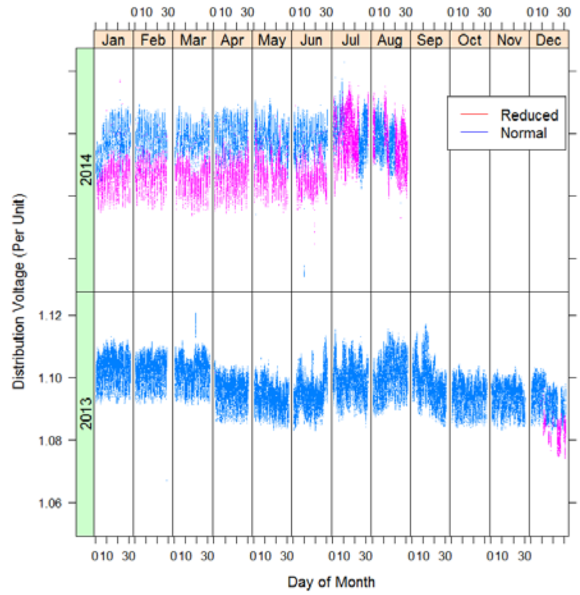
(g) South Pullman Feeder 122



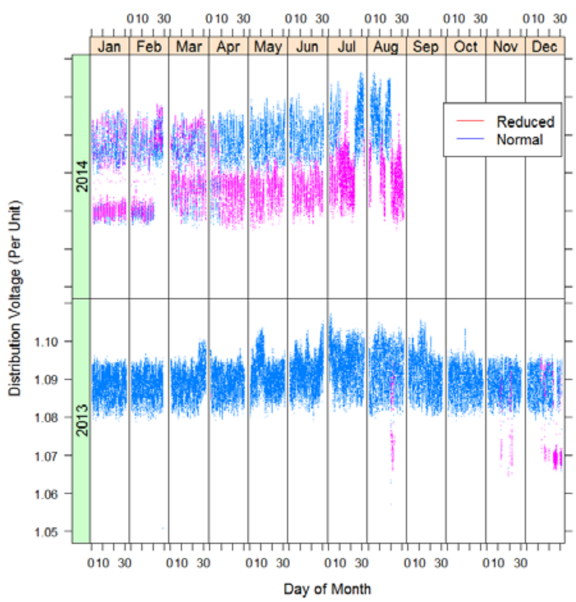
(h) South Pullman Feeder 123



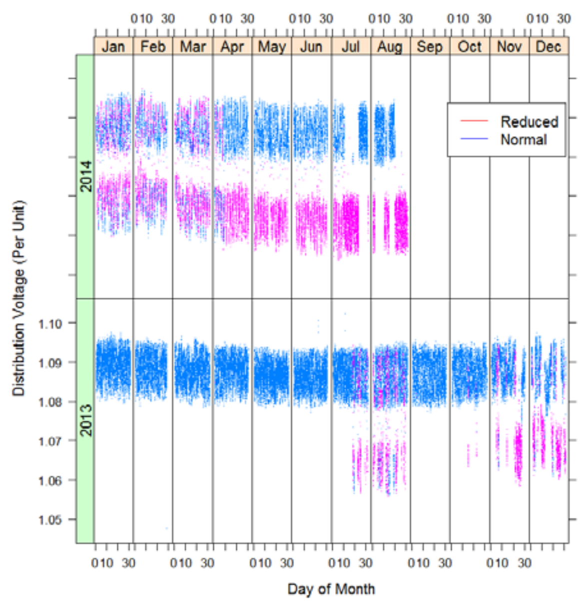
(i) South Pullman Feeder 124



(j) South Pullman Feeder 125



(k) Terre View Feeder 131



(l) Terre View Feeder 132

Figure 7.6. Average of Head-End Phase Voltages at Pullman Site Feeders. The legend refers to the reported status of the IVVC system, whether it is active (reduced) or normal.

The performance of distribution voltage management is sometimes based on changes in average end-of-line voltage rather than head-end distribution voltage. Avista Utilities measured end-of line phase voltages at a sample of its newly installed smart transformers (Section 7.3) and customer meters (Section 7.5). A sample is shown in Figure 7.7, which shows the averaged end-of-line phase voltages from Turner Feeder 111. The per-unit voltages of the individual phases have been offset from one another by 0.05 per unit so that they might be better viewed and compared. The availability of end-of-line voltages was sparse at this and other feeders. The Phase “b” voltage was entirely unavailable through much of 2013 and early 2014. Avista Utilities responded that smart transformers were placed at locations where low voltage was most likely. Phase “b”, in this case, simply happened to not be such a location.

The head-end and end-of-line representations of system voltage should mostly rise and fall in parallel for passive distribution systems. The two may differ somewhat with electrical loading that induces voltage drops across conductors and transformers and that counteracts the natural tendency for voltage to increase due to system capacitance. The differences would be more pronounced where the profile of voltage down a feeder’s length is being actively managed.

Active voltage management is evident in the end-of-line phase voltages as it was for head-end phase voltages. However, the end-of-line voltages exhibit some management of individual phases that was not evident from the head-end phase voltages. Both the normal and reduced voltages of Phase “a” have been increased during the first three weeks of February 2014, but the change did not occur in Phase “c.” There are weeks during 2014 when the magnitudes of the end-of-line phase voltages were changed independently.

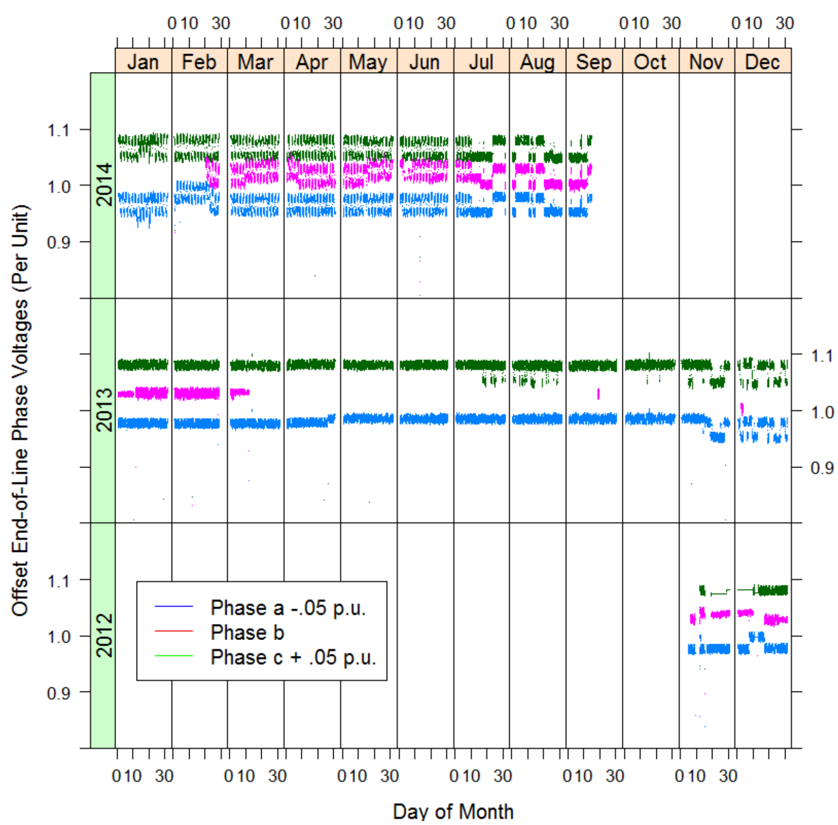
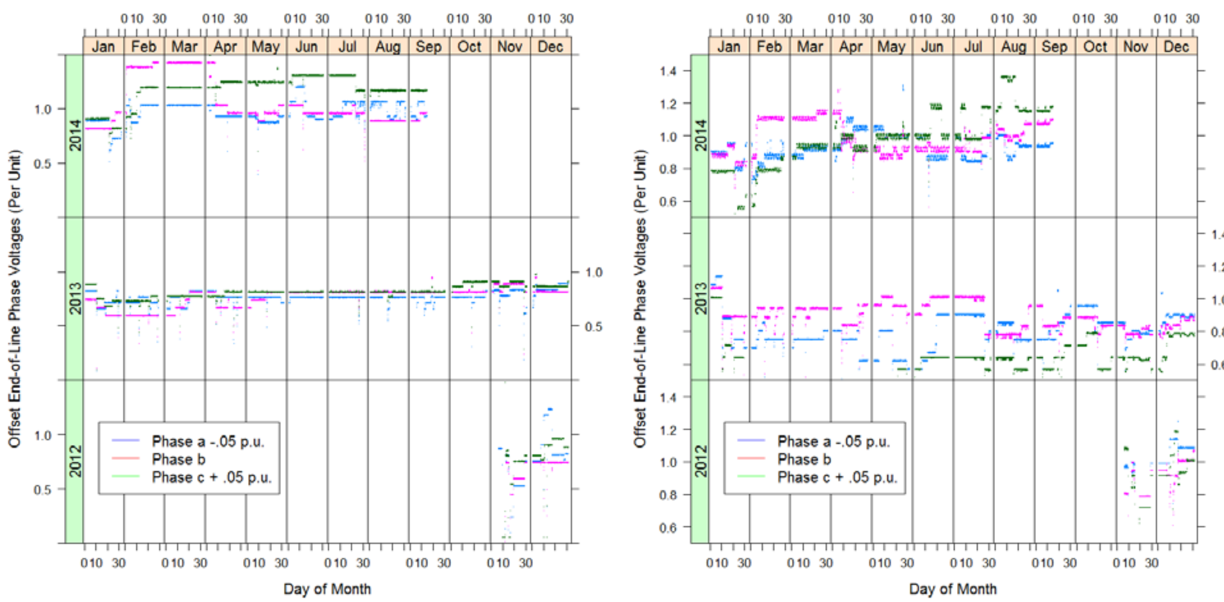


Figure 7.7. Averaged End-of-Line Phase Voltages from Turner Feeder 111. Per-unit values have been offset by 0.05 p.u. for readability.

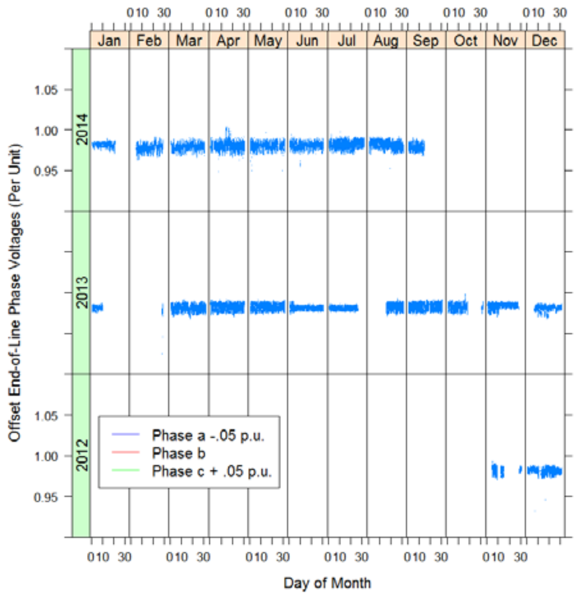
Avista Utilities reported during the project that the measurement sources of the end-of-line voltages had been difficult to calibrate and integrate. While the phase-voltage magnitudes of Figure 7.7 for Turner Feeder 111 seemed reasonable, the measurements at the phases of other feeders were not as credible. See Figure 7.8. Many of the phase voltages were found to have not been metered, and were therefore unavailable. No end-of-line phase voltages were available for South Pullman Feeders 122 and 125 or Terre View Feeder 131. Where available, magnitudes of the per-unit end-of-line voltages were often found to be far outside an acceptable voltage range.[1] Furthermore, the typical voltage magnitudes of individual phases were found to have changed over time. For these reasons, the project opted to use average head-end voltages, not end-of-line voltages, for its evaluations of IVVC system performance.



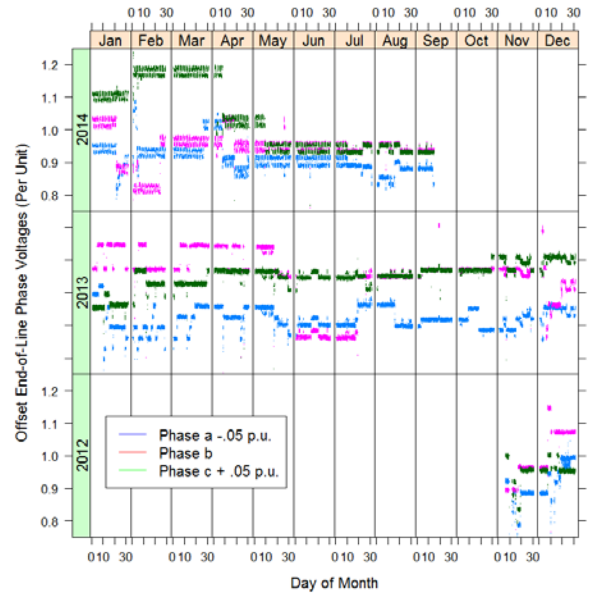
(a) Turner Feeder 112

(b) Turner Feeder 113

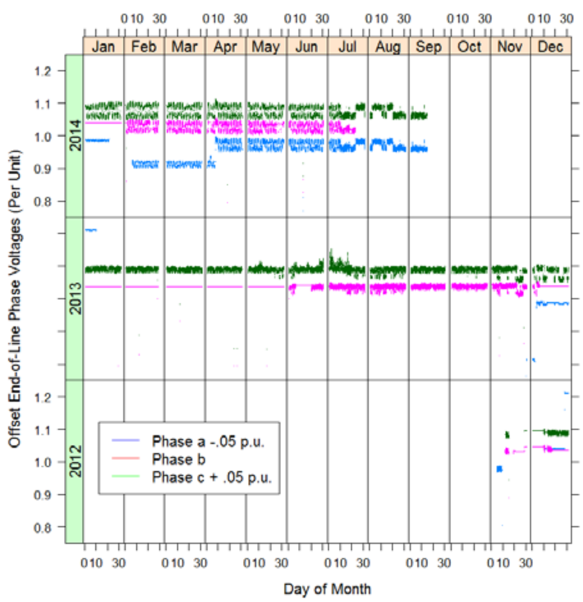
[1] On a 120 VAC basis, the per-unit voltages 0.95 and 1.05 correspond to the voltages 114 and 126 VAC, respectively.



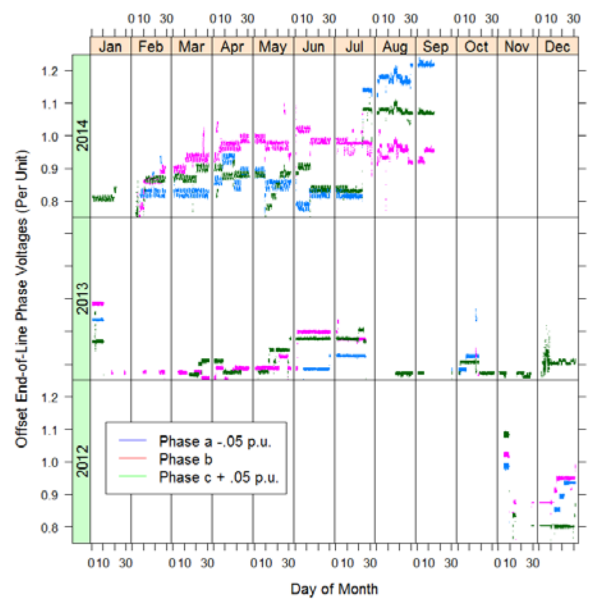
(c) Turner Feeder 115



(d) Turner Feeder 116



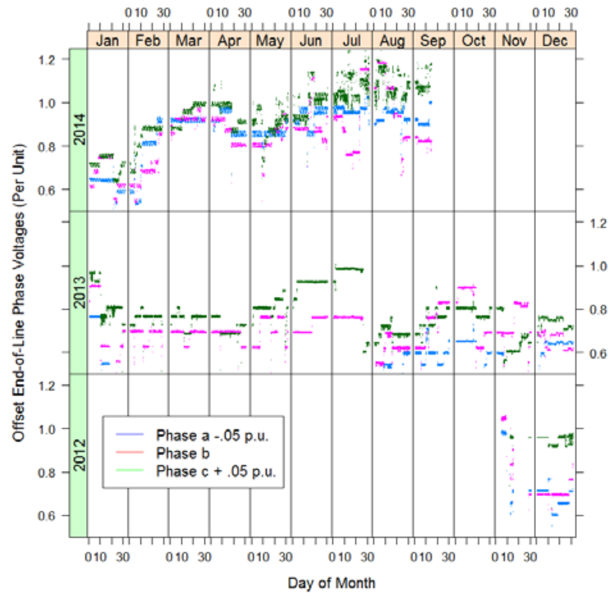
(e) Turner Feeder 117



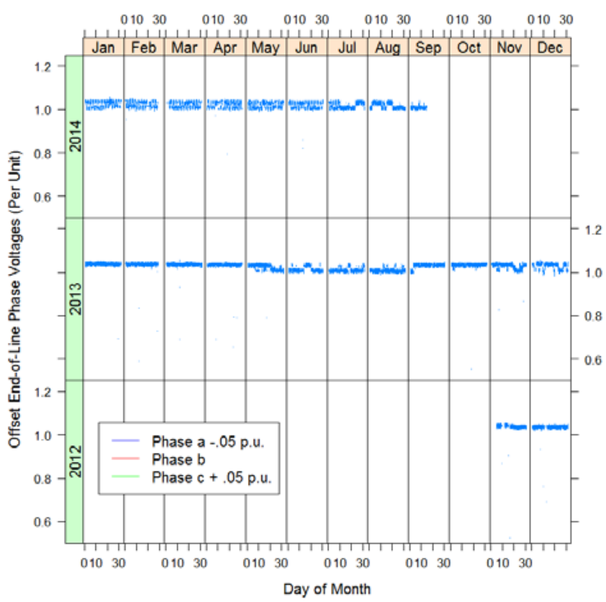
(f) South Pullman Feeder 121

NA

(g) South Pullman Feeder 122



(h) South Pullman Feeder 123

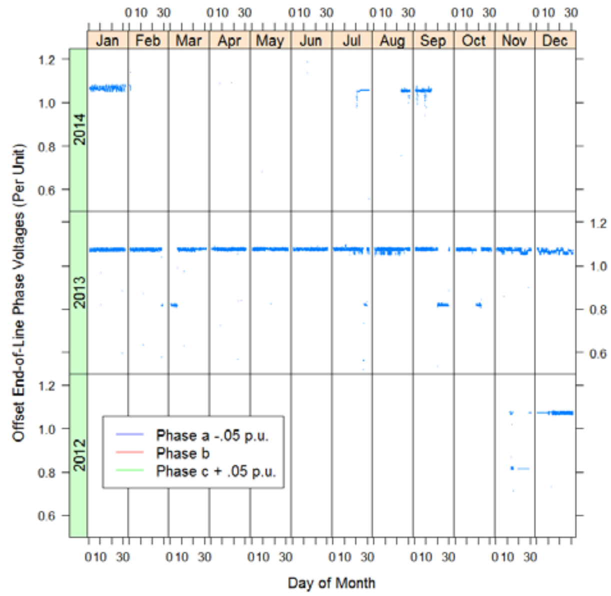


(i) South Pullman Feeder 124

NA

(j) South Pullman Feeder 125

NA



(k) Terre View Feeder 131

(l) Terre View Feeder 132

Figure 7.8. Averaged End-of-Line Phase Voltages from Turner Feeder 111. Per-unit values have been offset by 0.05 p.u. for readability. (NA = not available)

The other critical measurements important for evaluating the performance of IVVC are real and reactive powers. Avista Utilities supplied 5-minute feeder power data for a period from April 2013 into September 2014. An example of this time-series data from Turner Feeder 111 is shown in Figure 7.9. The power at this feeder has moderate variation by season. The feeder peaks in winter. A strong weekly consumption pattern is evident because consumption is less during weekends. No impact on power consumption from voltage management—expected to be only about a 2% change—is evident by inspection of the power time series.

Reactive power remained steady through 2012 with a moderate inductive load. After several trials and missteps, the reactive power was well corrected by May 2013 and remained good through 2013. It seems that experimentation resumed in 2014, allowing several changes in reactive power levels. Dynamic VAr control was evident during May 2014 and from late July into early September 2014, when the reactive power was modified frequently, perhaps on a daily basis. Avista Utilities confirmed that the testing was attributable to alternate-day testing that Navigant Consulting was completing on its behalf.

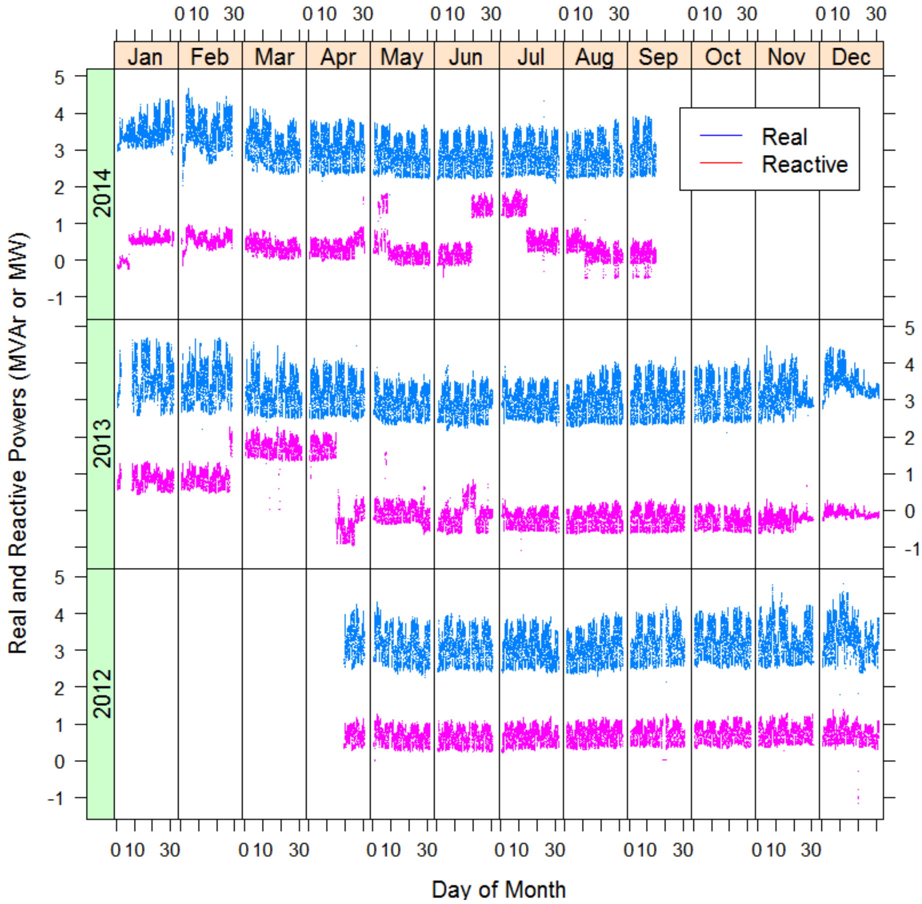
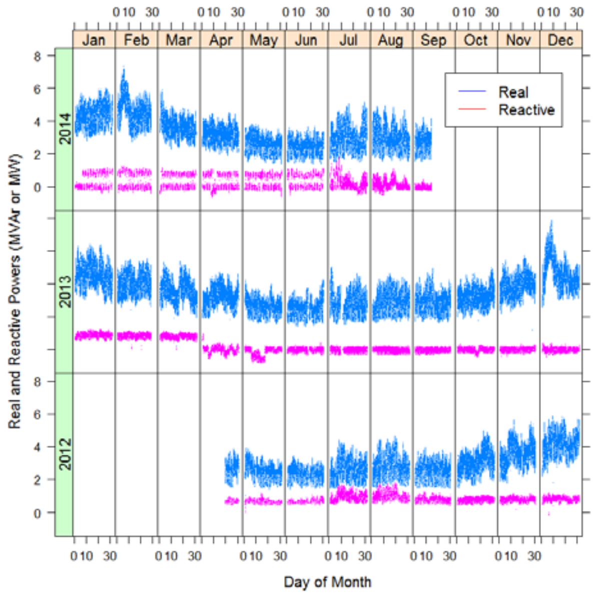


Figure 7.9. Real and Reactive Power Time Series for Turner Feeder 111

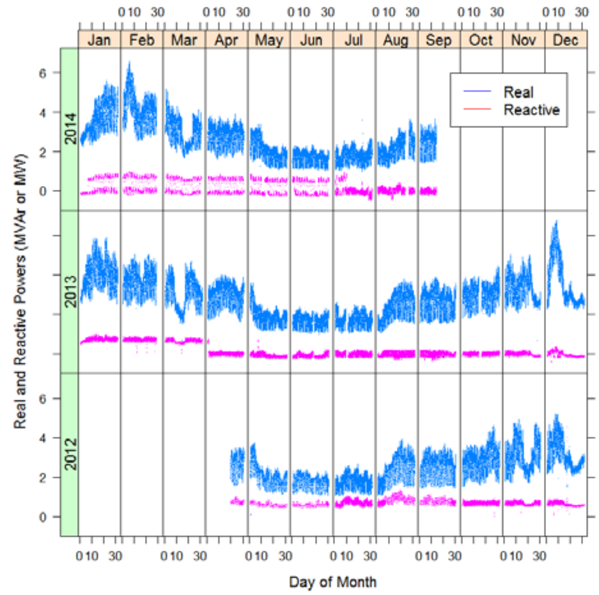
Real and reactive power time series for the remaining 12 Pullman site feeders are shown in panels of Figure 7.10. The diversity of the power consumption at the various feeders is intriguing. All the feeders except South Pullman Feeder 125 and Terre View Feeder 131 experienced their peak during winters. Like Turner Feeder 111, Turner Feeders 115 and 117 and South Pullman Feeder 124 exhibited strong weekly patterns with greatly reduced consumption during weekend days.

The reactive powers of all but four Pullman site feeders appear to have been corrected from small inductive levels starting in April 2013. The project does not know the details of these improvements, but they are likely the result of careful correction of static capacitor settings and circuit topology in those months. At South Pullman Feeder 121, moderate capacitive load was corrected. The reactive powers at Turner Feeder 117 and at both the Terre View Feeders 131 and 132 were already small and were probably not changed in April 2013.

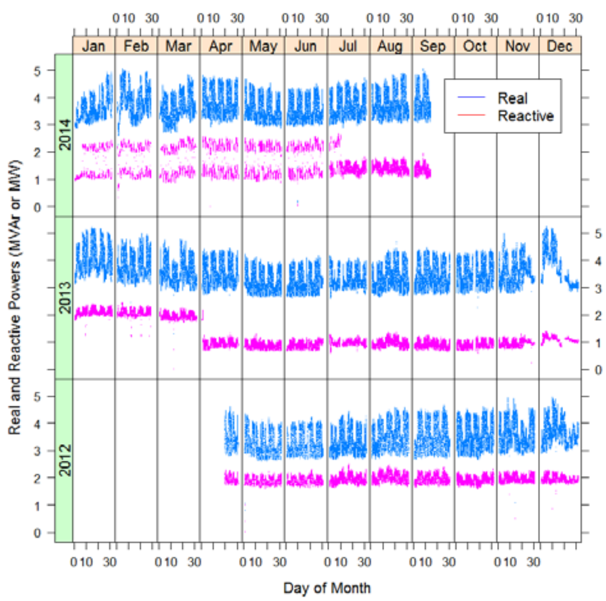
The reactive powers of all but the two Terre View feeders were dynamically managed at times during 2014. This is inferred from the periods in Figure 7.10 when the reactive power appears to have two values. In fact, these are rapid transitions, perhaps day-on/day-off transitions, between two reactive power levels.



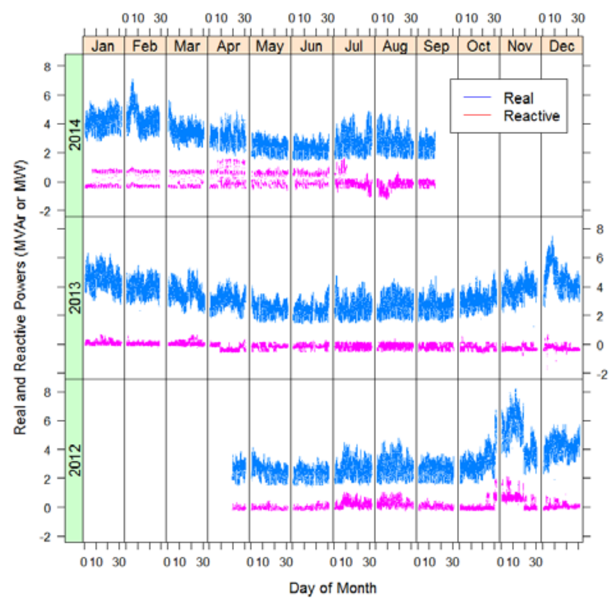
(a) Turner Feeder 112



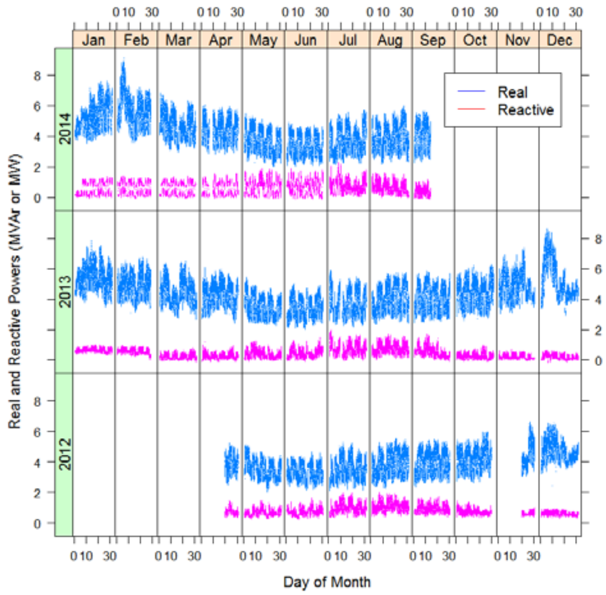
(b) Turner Feeder 113



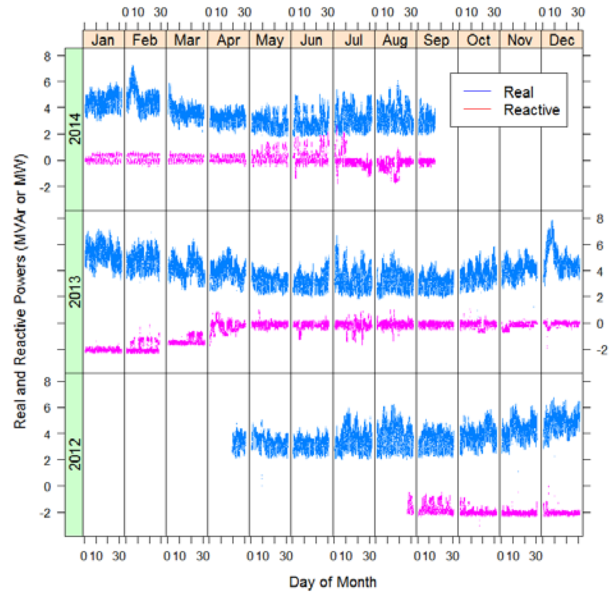
(c) Turner Feeder 115



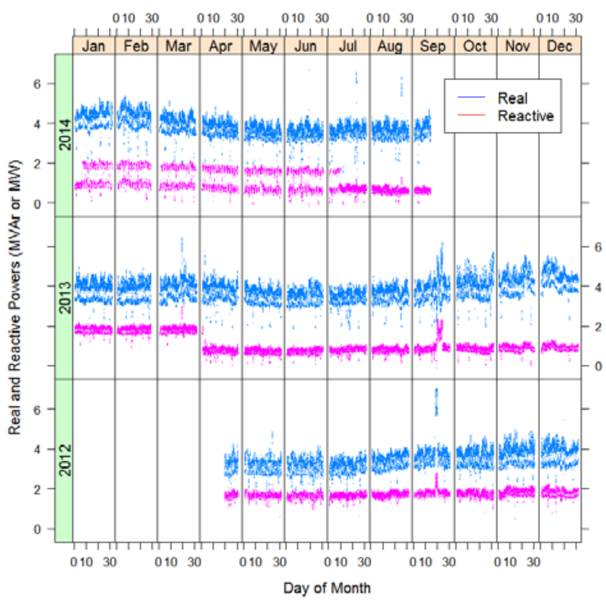
(d) Turner Feeder 116



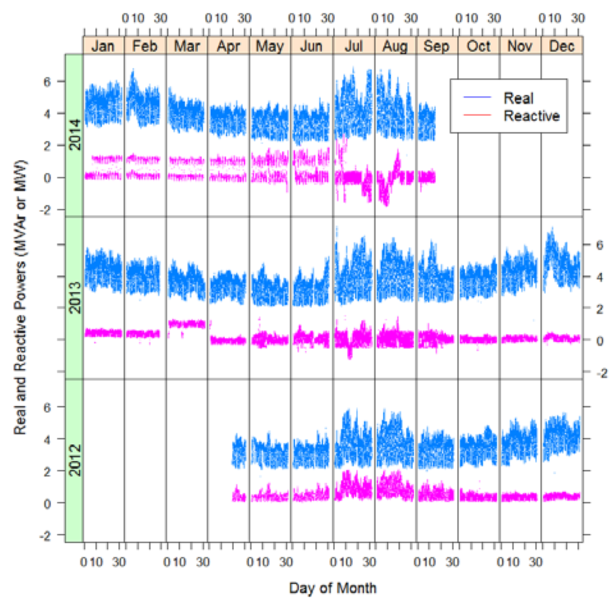
(e) Turner Feeder 117



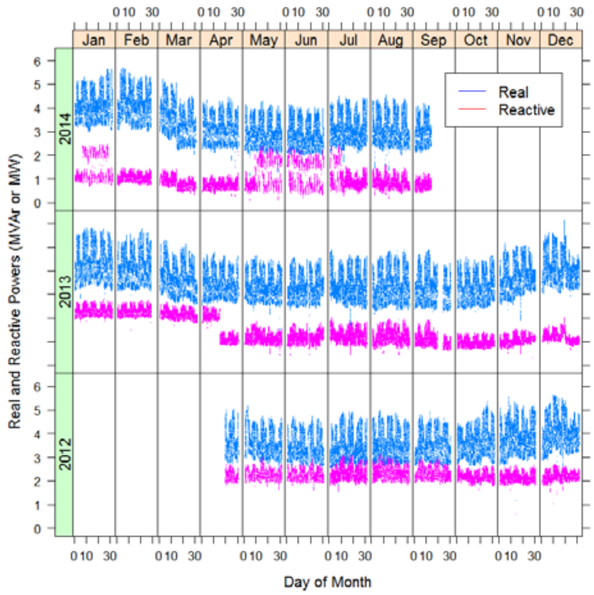
(f) South Pullman Feeder 121



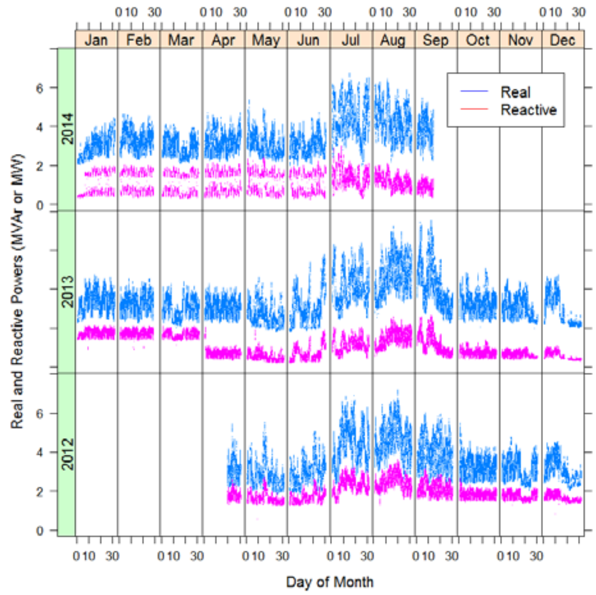
(g) South Pullman Feeder 122



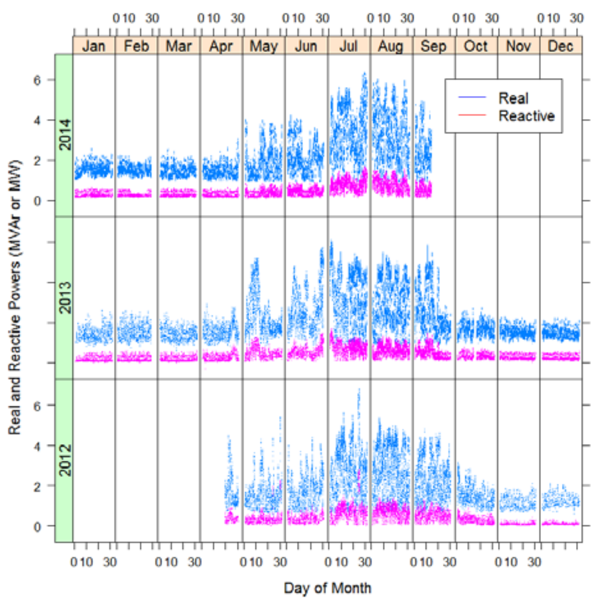
(h) South Pullman Feeder 123



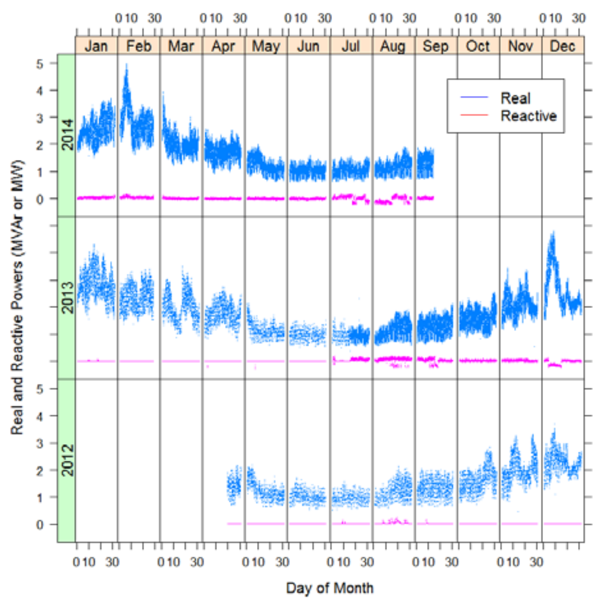
(i) South Pullman Feeder 124



(j) South Pullman Feeder 125



(k) Terre View Feeder 131



(l) Terre View Feeder 132

Figure 7.10. Real and Reactive Power Time Series for Pullman Site Feeders

Two of the three regression methods that were used in the analysis of the Pullman IVVC system incorporated temperature correction. A time series of ambient temperature data was found from weather station KPUW that is located at the Pullman-Moscow Regional Airport. The raw, sampled time series had missing intervals after it was moved to the project's 5-minute interval data frame. The data also possessed outliers at and near 0°F. To fix these shortcomings, a small band of data was first removed within the range −1.4°F to 1.4°F. This range was adjusted incrementally until the outliers disappeared upon visual inspection. The indiscriminate filter admittedly removed some valid data, as this is a relatively cold site. This data and data in many other missing data intervals were recovered by simple interpolation. The interpolation was permitted where the missing data interval was shorter than 6 hours.

The resulting time series of measured and interpolated temperatures is shown in Figure 7.11.

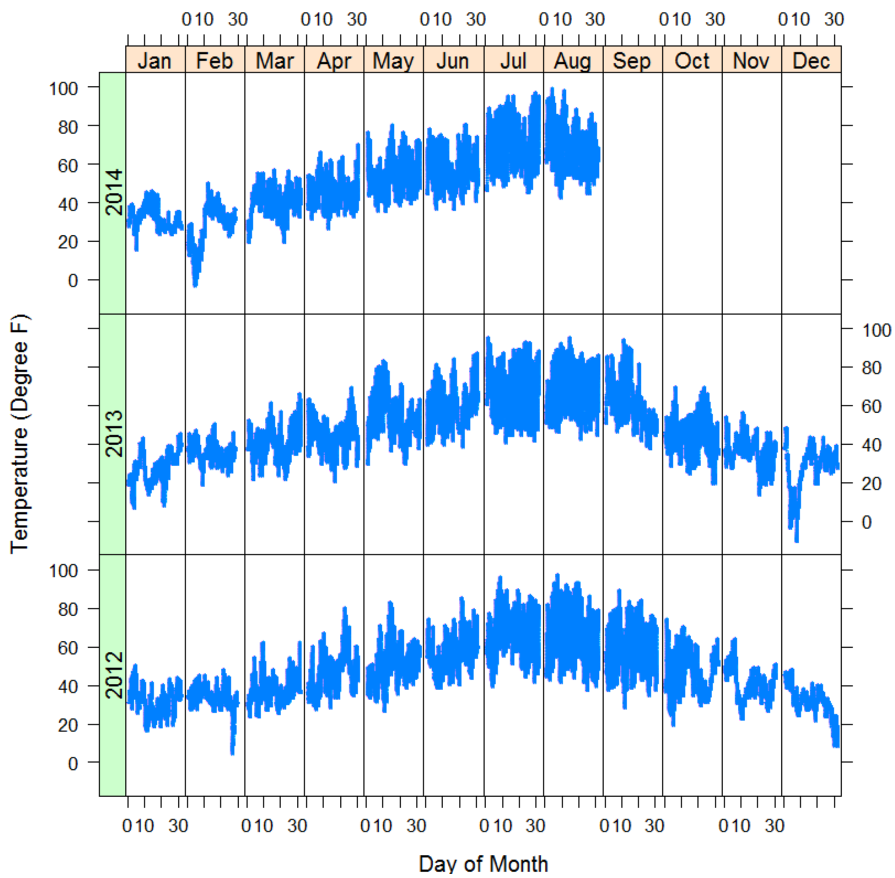


Figure 7.11. Series of Temperature Data from Weather Station KPUW at the regional Pullman-Moscow Regional Airport

IVVC might be expected to increase the number of switching events incurred by regulators and by controllable capacitors. The increased numbers of switching events may stress and shorten the life of affected distribution switch equipment. The data supplied to the project did not support a count of regulator switching actions that might have been then correlated with dynamic voltage management. However, the project received the counts of capacitor switching operations that had occurred each hour at each of the five South Pullman feeders. These sum counts were further aggregated by month and are shown in Figure 7.12. With the exception of a single outlier month, March 2012, for South Pullman Feeder 121, the sum counts of monthly switching operations were small before April 2013. The counts were observed to increase for all five feeders in 2014 as tests of VAr management were peaking. The counts at South Pullman Feeders 121 and 123 were strongly increased in 2013 and 2014, reaching counts of hundreds of switching events per month.

Based on Figure 7.12, there might be a valid concern that IVVC is stressing controllable capacitor banks.

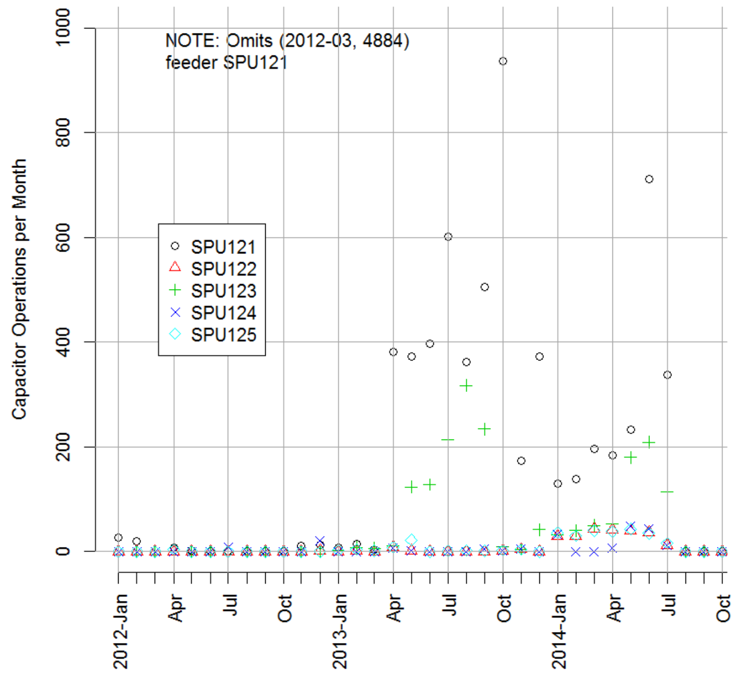


Figure 7.12. Monthly Counts of Capacitor Switching Operations, South Pullman Feeders

7.1.2 Analysis of the Avista Utilities Voltage Optimization System

Having observed evidence of voltage management among the raw phase-voltage data in late 2013 and in 2014, the project constructed distributions of the averaged phase voltages like the one shown in Figure 7.13 for Turner Feeder111. The histogram includes the counts of data intervals from only 2014. The histogram clearly shows a combination of two populations of voltage magnitudes on this feeder in 2014.

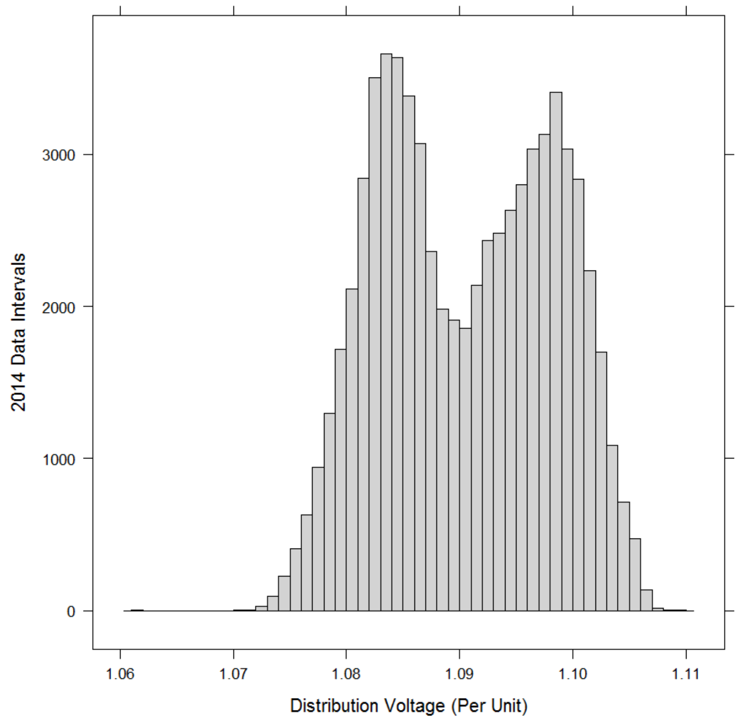
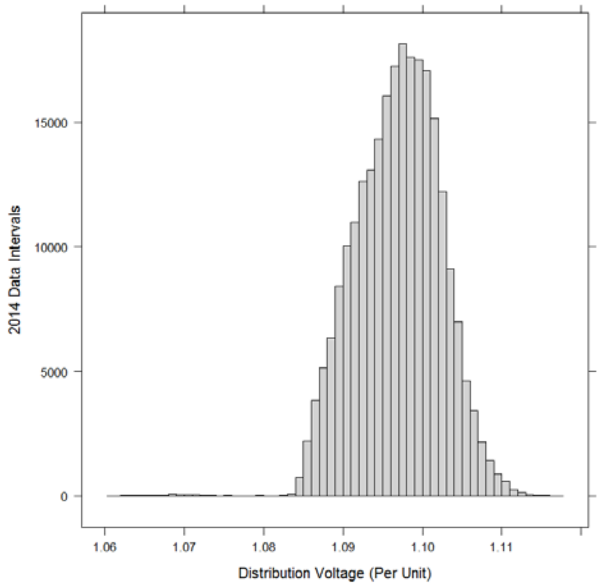


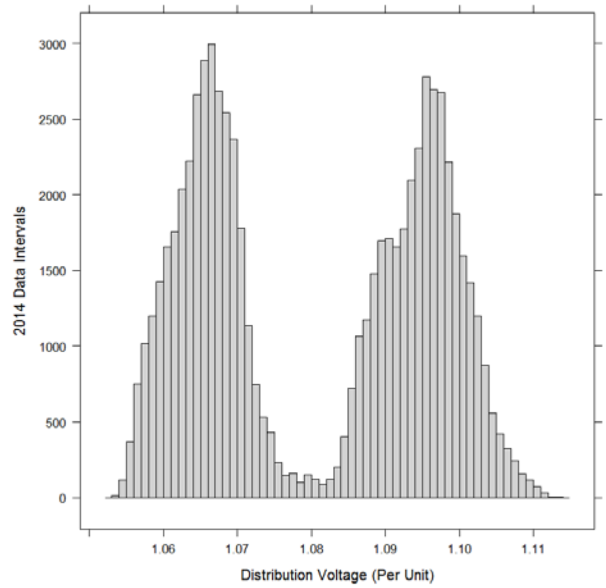
Figure 7.13. Histogram of Averaged Per-Unit Phase-Voltage Measurements for Turner Feeder 111 during 2014

The averaged phase-voltage histograms for the remaining 12 Pullman site feeders are shown in Figure 7.14. In addition to Turner Feeder 111, two or more distinct operational voltage levels are evident from these histograms on nine feeders: Turner Feeders 113, 116, and 117; South Pullman Feeders 121, 123 and 125; and both the Terre View Feeders 131 and 132. The separation of the voltages at South Pullman Feeder 125 was small, and there was much overlap between the voltages of the two operational modes. A third voltage level was suggested by the distribution for Terre View Feeder 131.

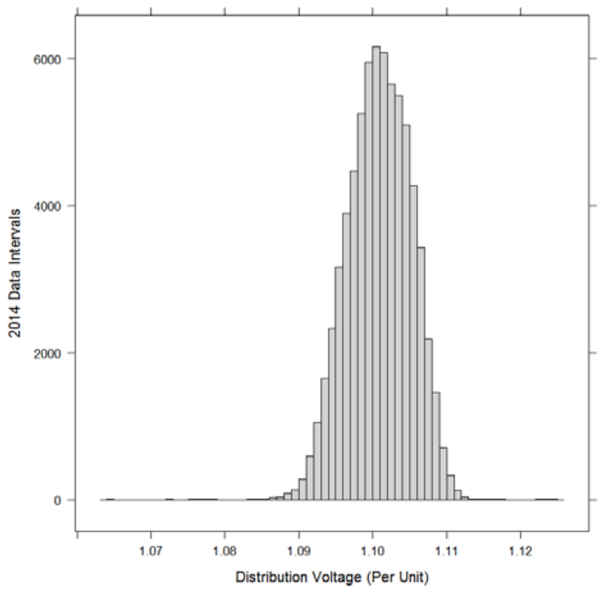
Thus, during 2014, distinct voltages might have been accurately identified at eight of the feeders based solely on a voltage threshold between the data populations. Fortunately, the project did not need to do so because the utility supplied a relatively accurate indicator of its voltage management intentions.



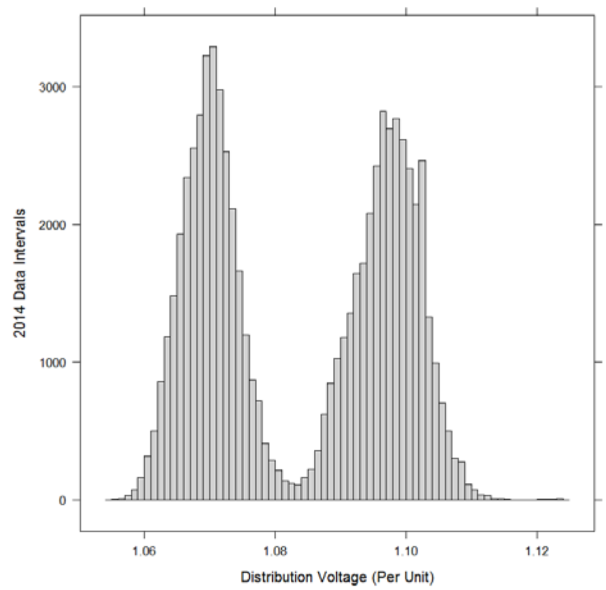
(a) Turner Feeder 112



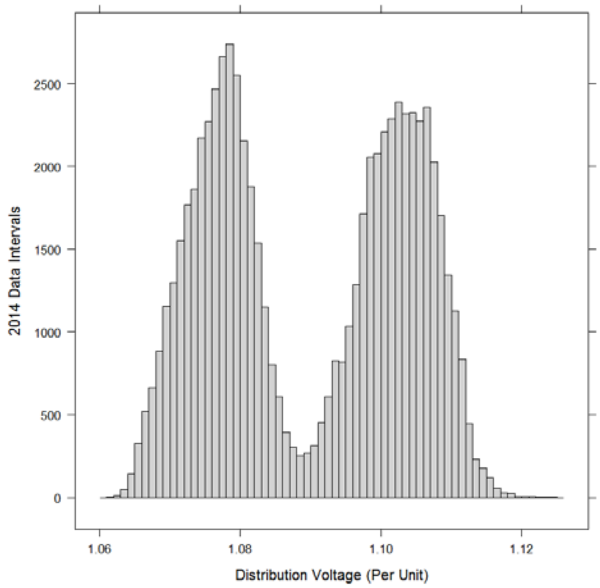
(b) Turner Feeder 113



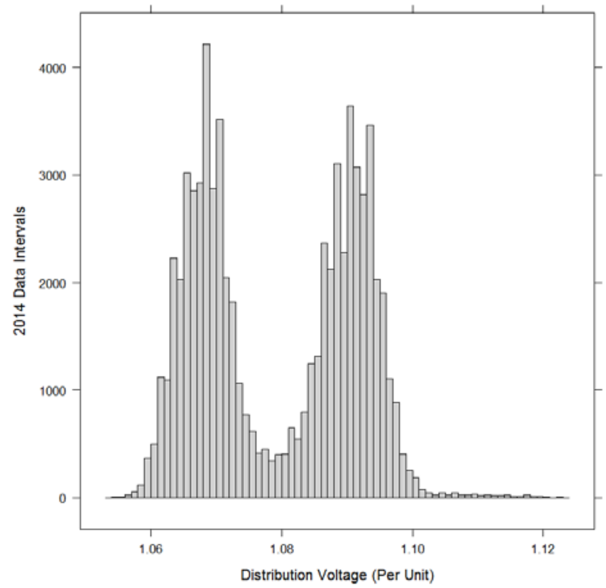
(c) Turner Feeder 115



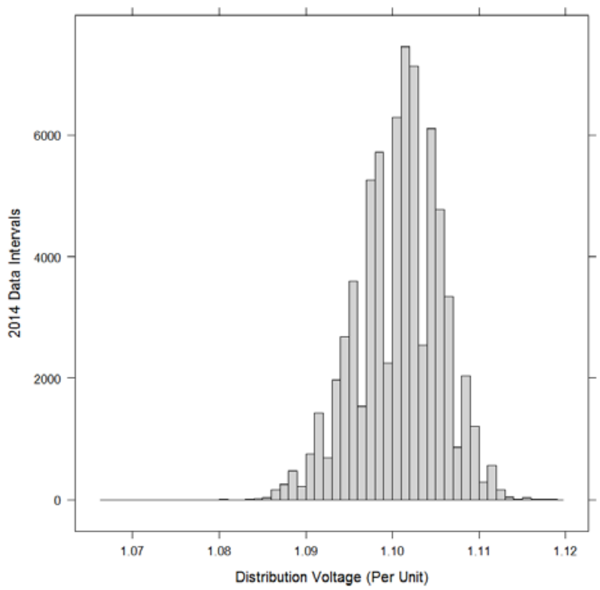
(d) Turner Feeder 116



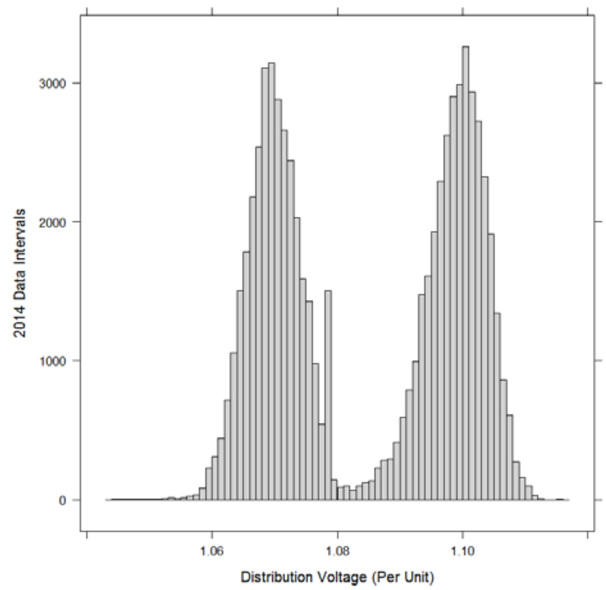
(e) Turner Feeder 117



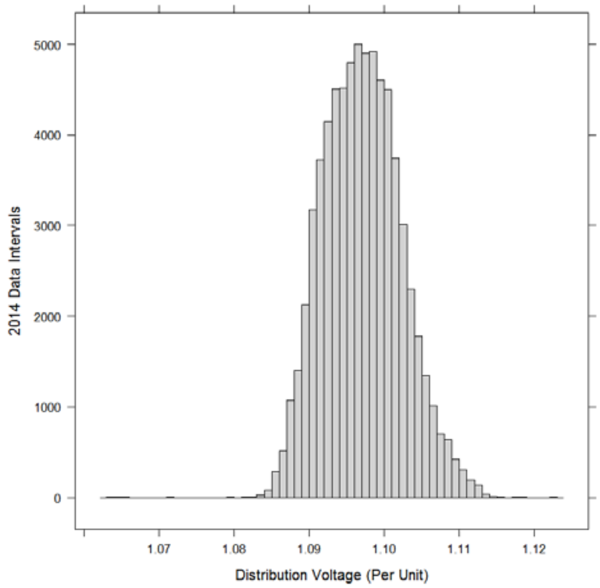
(f) South Pullman Feeder 121



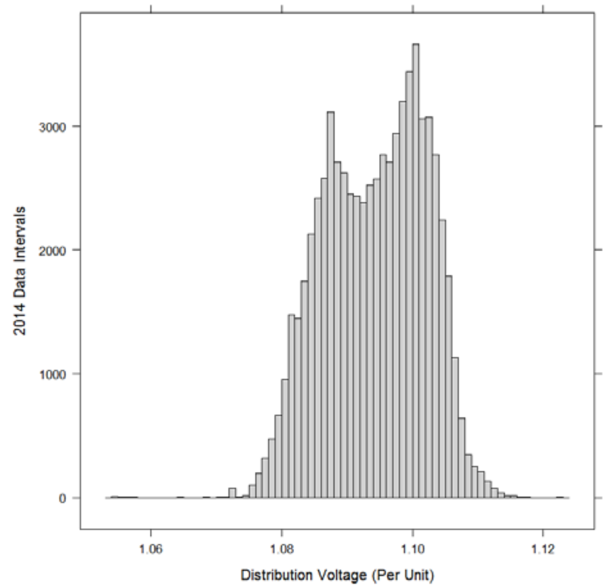
(g) South Pullman Feeder 122



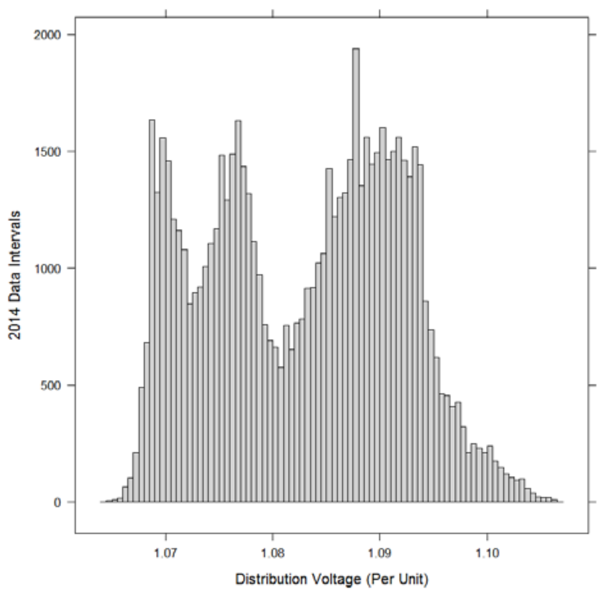
(h) South Pullman Feeder 123



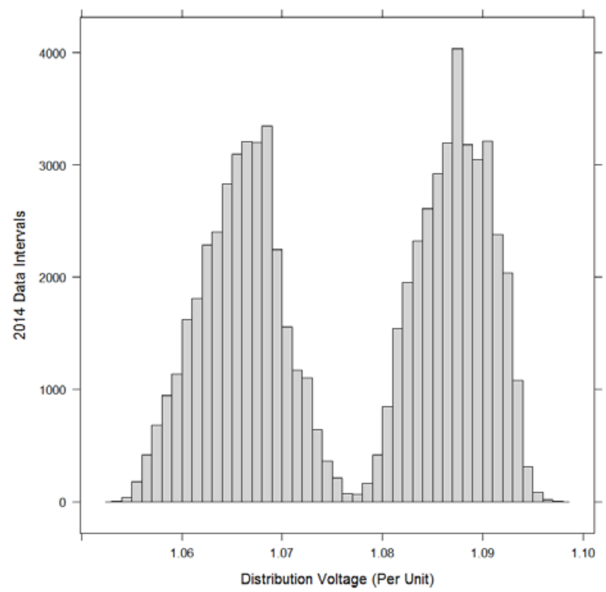
(i) South Pullman Feeder 124



(j) South Pullman Feeder 125



(k) Terre View Feeder 131



(l) Terre View Feeder 132

Figure 7.14. Histograms of the Averaged Per-Unit Phase-Voltage Measurements for 12 Pullman Site Feeders during 2014

Figure 7.15 shows information that is similar to that in histogram Figure 7.13, but using a quartile plot. Both figures are constructed for Turner Feeder 111, but the quartile plot includes all project data, whereas the prior histogram showed only data from 2014. Additionally, the separation between the two data populations in the quartile plot is based on the reported status of the feeder's voltage management that was reported to the project by the utility. Voltage is being managed (reduced) on the right ("Active") side, not on the left ("Normal") side. Any inaccuracy in the reporting of voltage management status for this feeder would affect the accuracy of the distributions shown in this plot. Specifically, such inaccuracies would typically lessen the distinction between the two data populations.

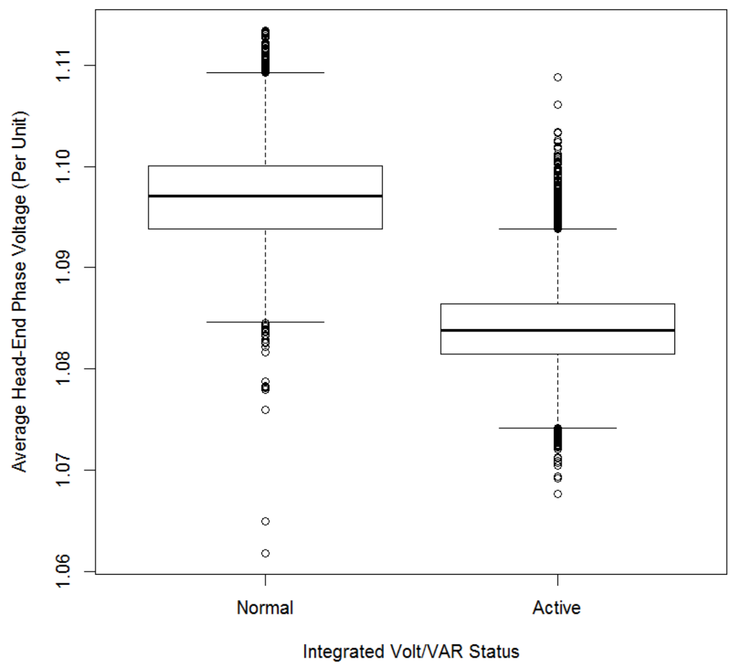
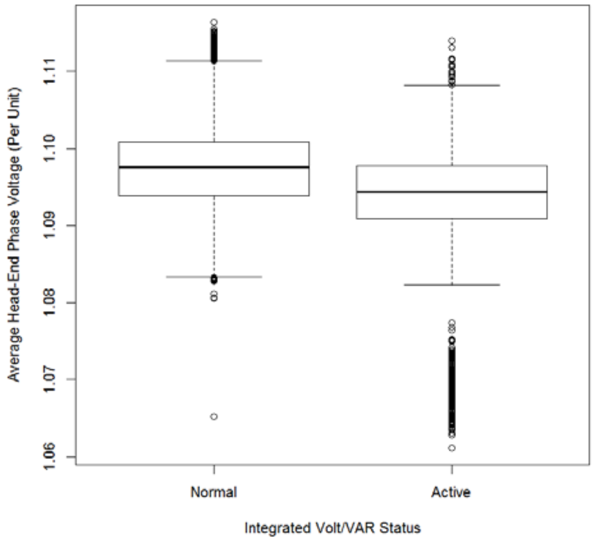
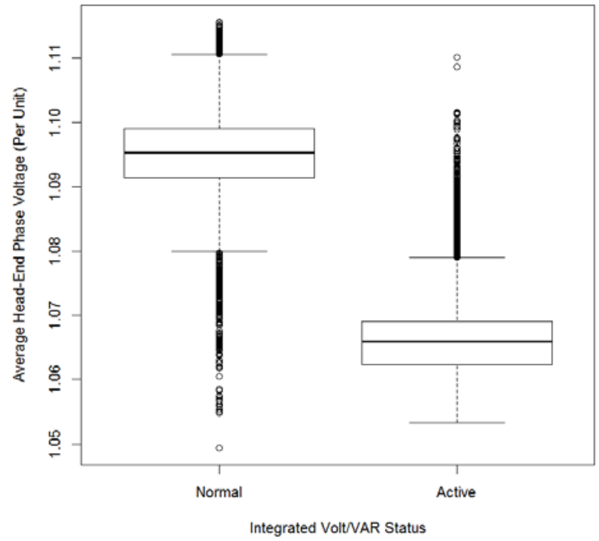


Figure 7.15. Quartile Distributions of Average Head-End Phase Voltages at Turner Feeder 111

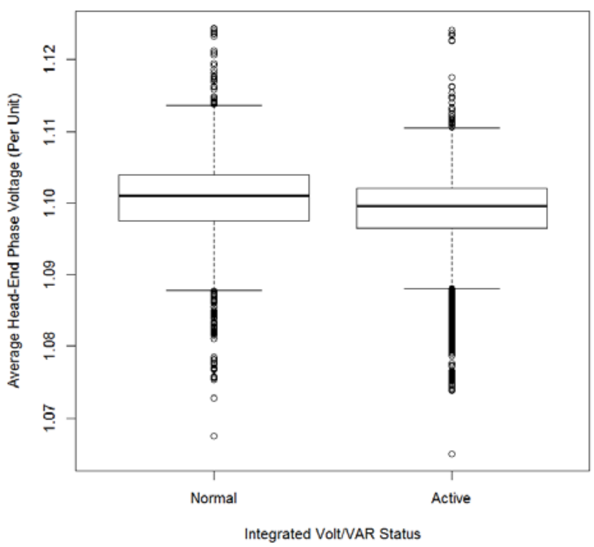
The quartile plots of active and normal head-end voltage data for the remaining 12 feeders are shown in Figure 7.16. The conclusions to be drawn are similar to those that were drawn from the histograms of Figure 7.14. It is noteworthy that the head-end feeder voltages at South Pullman Feeder 122 *increased* during times that voltage management was reportedly active. This is the only anomaly in that respect.



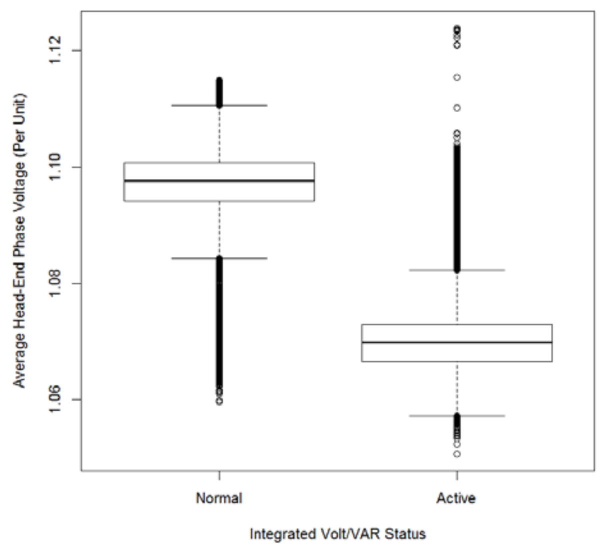
(a) Turner Feeder 112



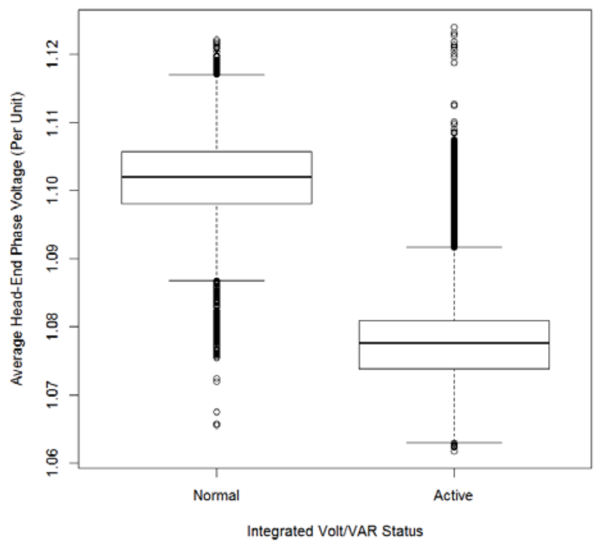
(b) Turner Feeder 113



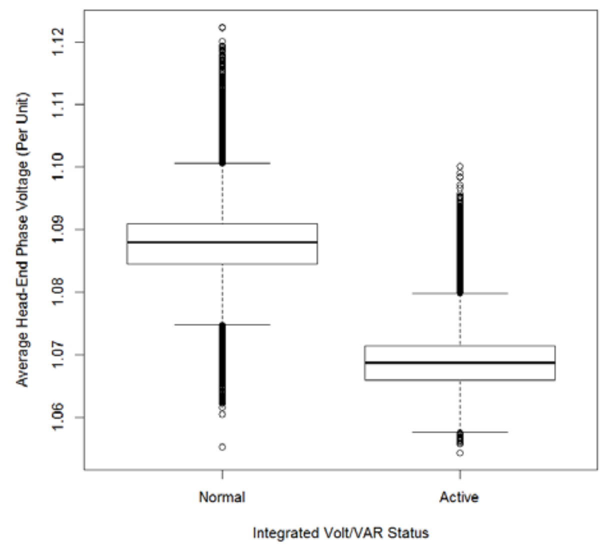
(c) Turner Feeder 115



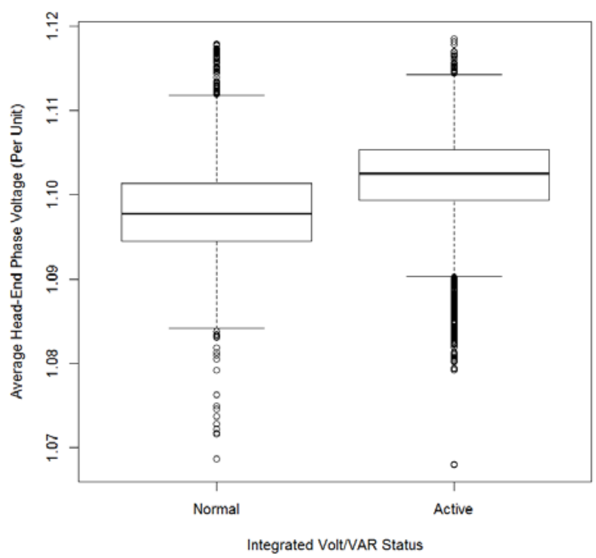
(d) Turner Feeder 116



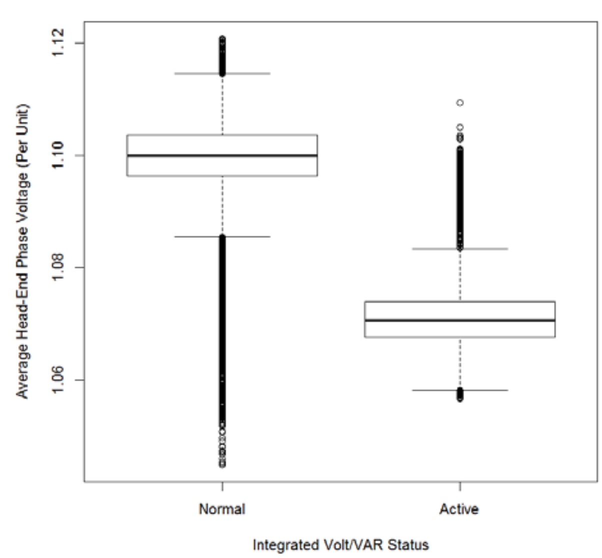
(e) Turner Feeder 117



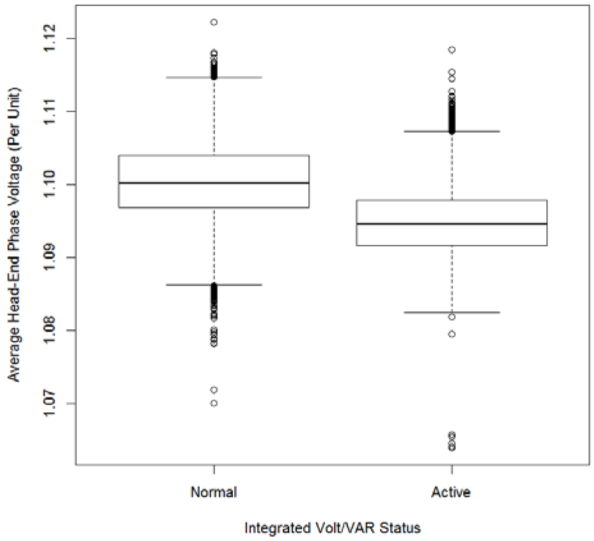
(f) South Pullman Feeder 121



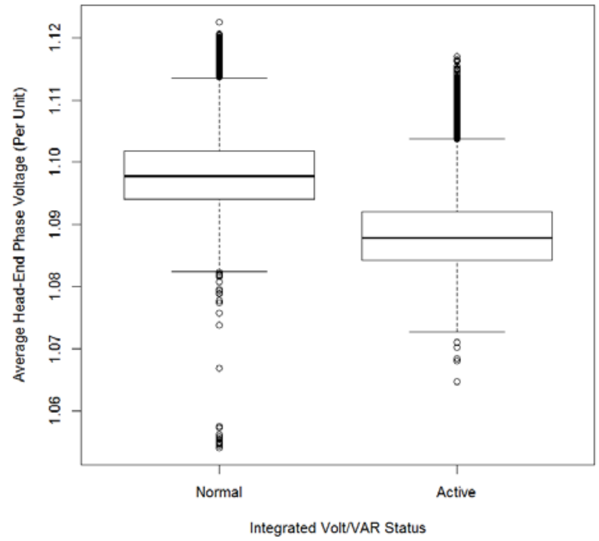
(g) South Pullman Feeder 122



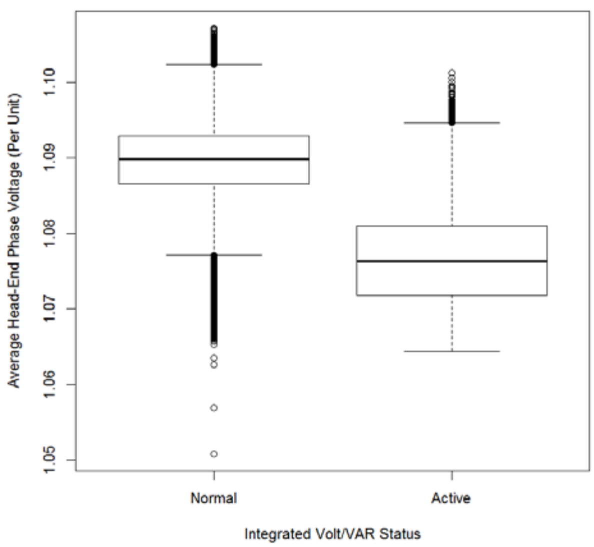
(h) South Pullman Feeder 123



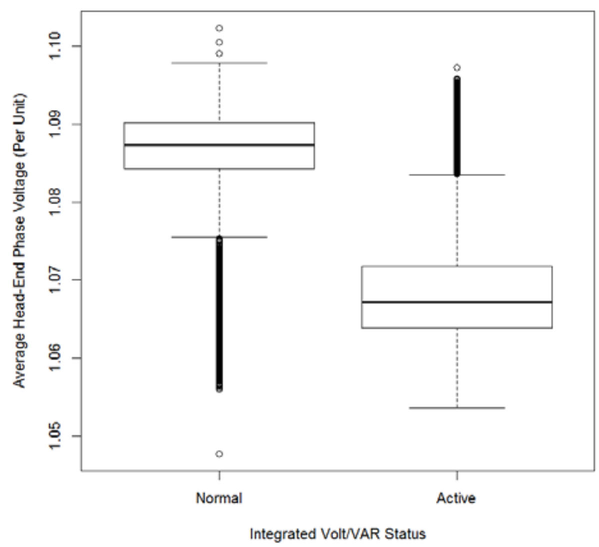
(i) South Pullman Feeder 124



(j) South Pullman Feeder 125



(k) Terre View Feeder 131



(l) Terre View Feeder 132

Figure 7.16. Quartile Distributions of Average Head-End Phase Voltages when the Integrated Volt/VAr System is Normal (not active) and Active

While the project might have directly analyzed reactive power, power factor is probably a better indicator of the success of an IVVC system. It is nicely normalized, a metric that always lies between zero and unity. At unity power factor, no reactive power is being supplied, either capacitive or inductive, and the minimum amount of conductor current is being used to supply the power needed on the feeder. Distribution line losses are thereby minimized, too.

Figure 7.17 is the time series of calculated power factors for Turner Feeder 111. Power factor is a function of real and reactive power. The project calculated the power factor for each data interval for which both valid real and reactive powers had been reported. The power factor on this feeder was observed to be reasonable through 2012. The power factor was good in 2012, but it never reached unity. After a precipitous drop in March and April 2013, the power factor improved and remained improved through the rest of 2013. Testing appears to have intermittently taken place during 2014, causing the power factor to sometimes return to the 2012 and early 2013 management standards.

The project received no useful indicator when reactive power was being managed and not on the feeders. Color was applied in Figure 7.17 according to the indicator that had proven accurate and useful concerning voltage management. The correlation between power factor level and this indicator is weak at this feeder, suggesting that VArs and volts were individually controlled. Possessing no strong indicator of the utility's intentions for VAr management on this feeder, the project's analysis of these impacts was diluted and imprecise.

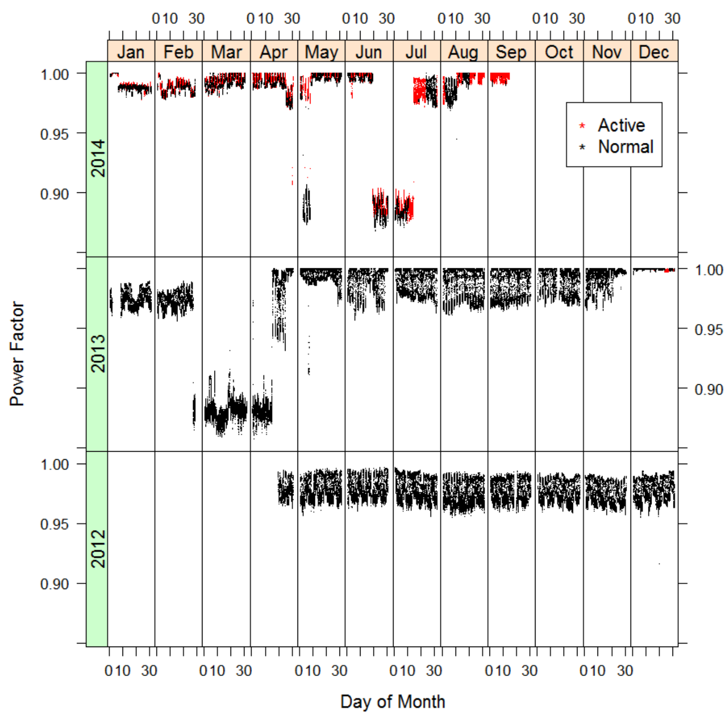
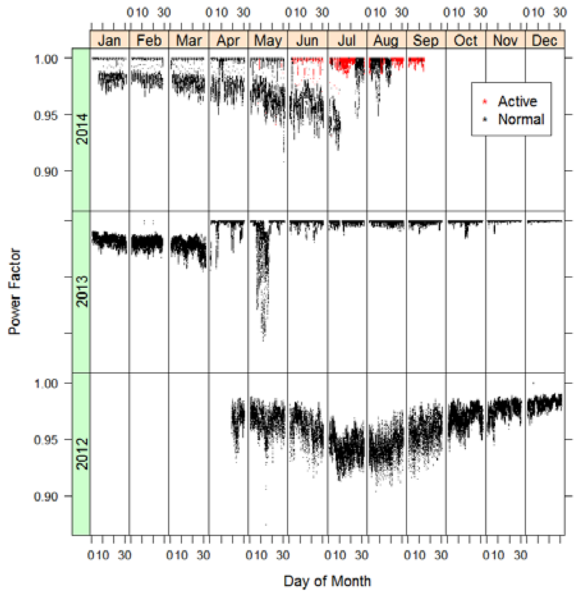
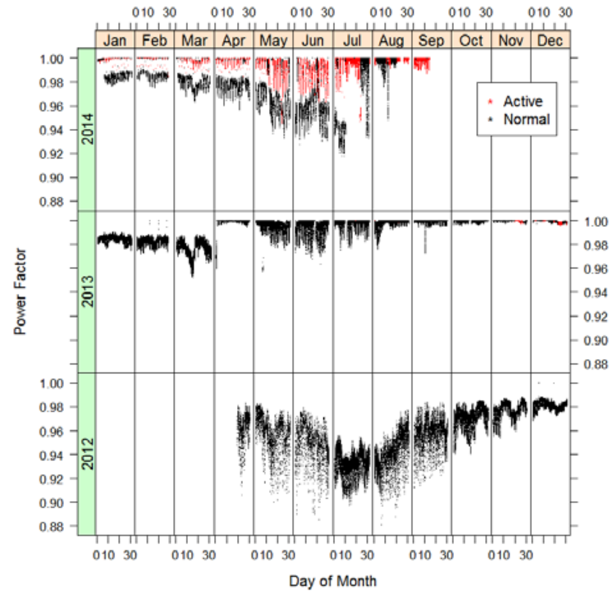


Figure 7.17. Calculated Power Factor for Turner Feeder 111

The calculated power factors on the other 12 feeders are shown in the panels of Figure 7.18. Marked improvements in feeders' power factors were observed beginning in April 2013 at all but four feeders—Turner Feeder 116, South Pullman Feeder 123, and Terre View Feeders 131 and 132. This observation had already been made based on reactive power levels. Some degree of reactive power management testing was evident at all of the Pullman site feeders, except perhaps South Pullman Feeder 121 and Terre View Feeder 132. Although the accuracy of the correlation was always questionable, some degree of correlation between the calculated power factors and the reported status of the voltage management system existed at all the feeders except South Pullman Feeder 121 and Terre View Feeder 132. The analyzed impacts of reactive power dynamic management were diluted by the lack of a clear signal that indicates when the utility is actively managing VArs and when it is not.



(a) Turner Feeder 112



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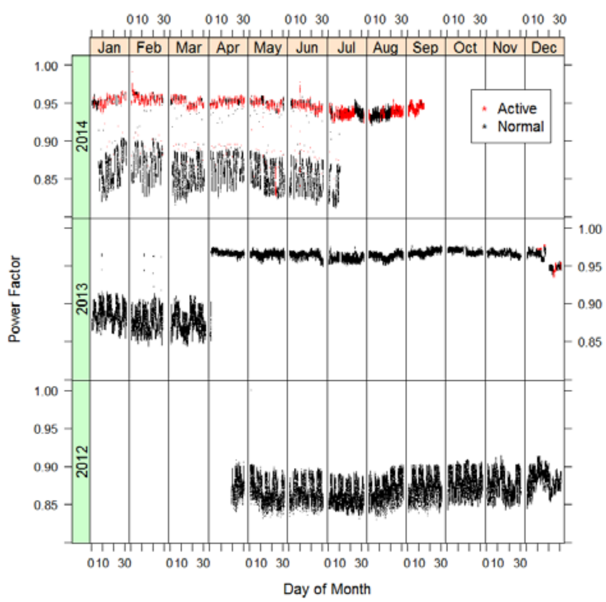
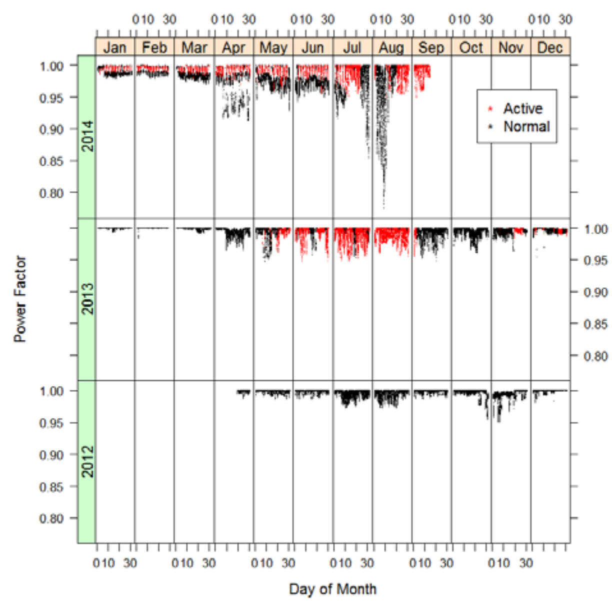
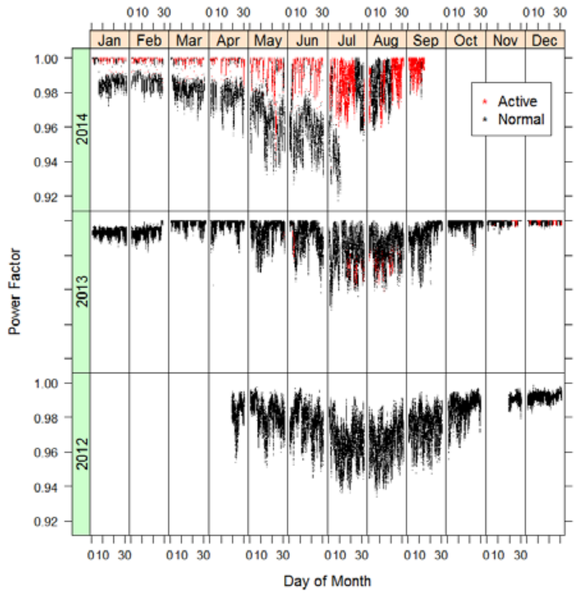


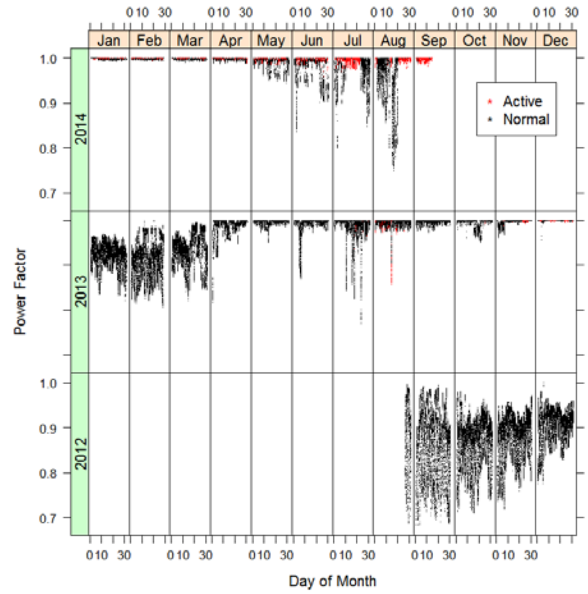
(c) Turner Feeder 115



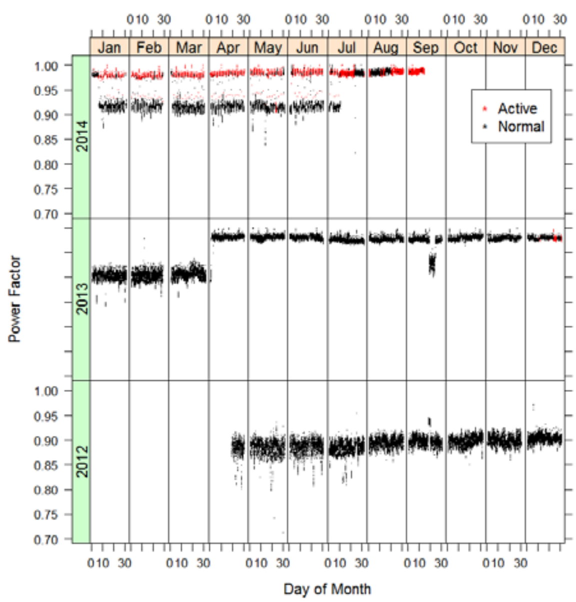
(d) Turner Feeder 116



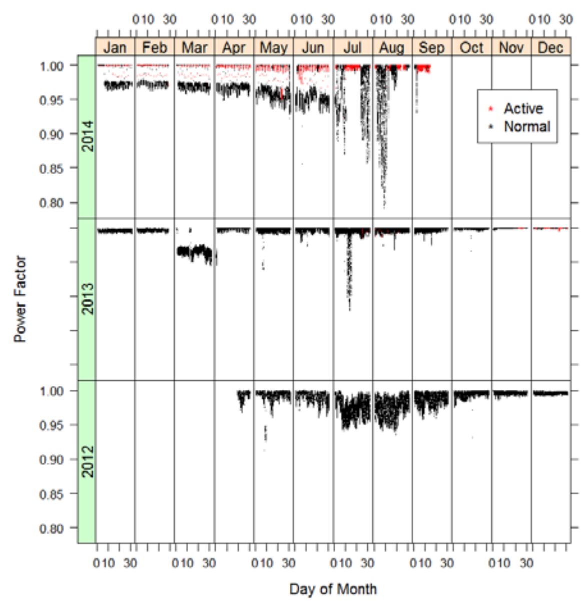
(e) Turner Feeder 117



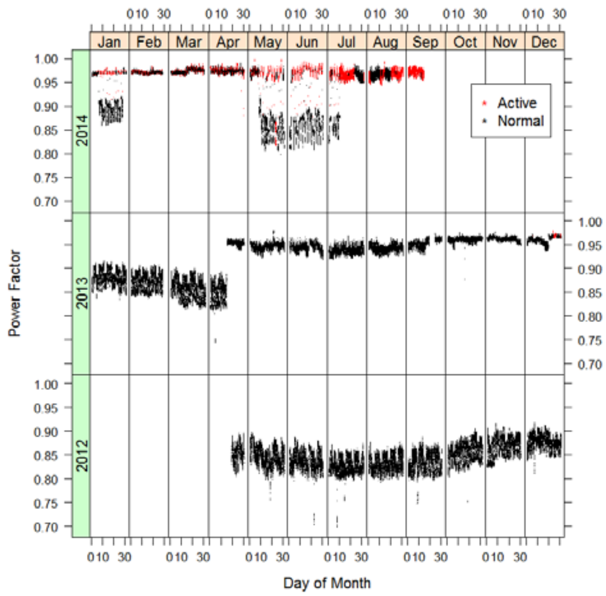
(f) South Pullman Feeder 121



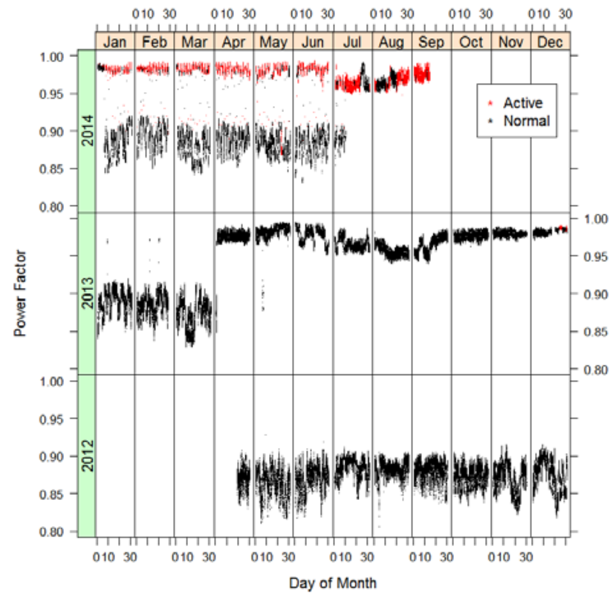
(g) South Pullman Feeder 122



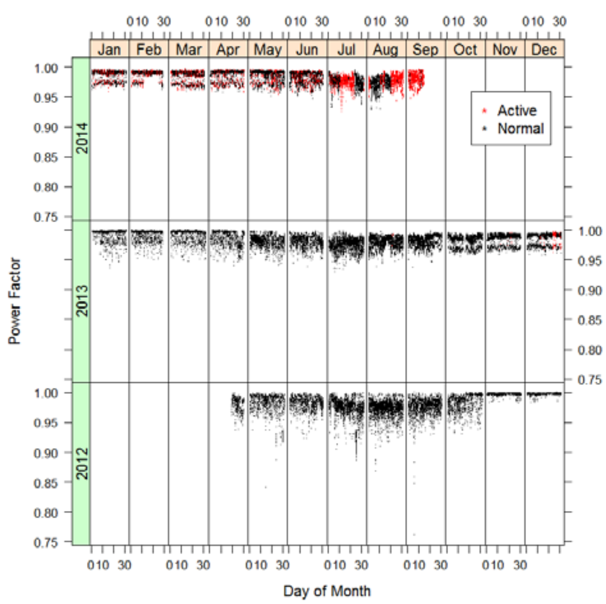
(h) South Pullman Feeder 123



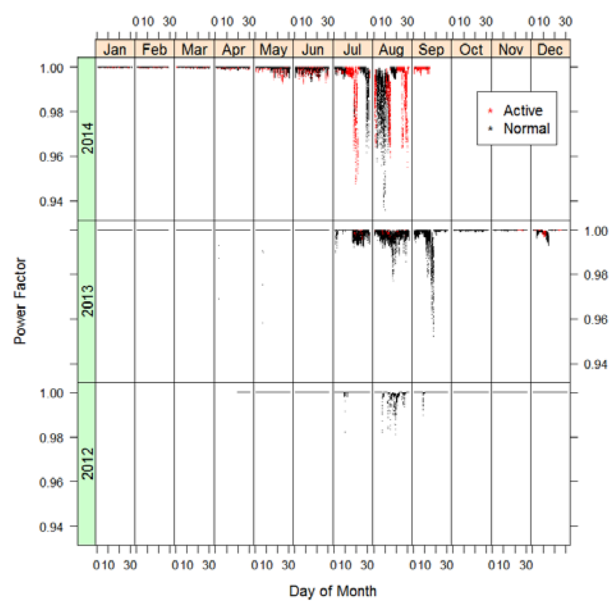
(i) South Pullman Feeder 124



(j) South Pullman Feeder 125



(k) Terre View Feeder 131



(l) Terre View Feeder 132

Figure 7.18. Calculated Power Factors for Pullman Site Feeders

It has been pointed out several times that the reactive power management practices at the Pullman site appear to have been changed several times during the PNWSGD. This observation is quantified in Figure 7.19, which shows the quartile distributions of calculated power factors at Turner Feeder 111 separately for years 2012, 2013, and 2014. The 2012 values preceded the utility's efforts to correct power factor, which became fully effective in April 2013. After the correction of April 2013 had taken place, the utility maintained these calibrations and configurations through the remainder of 2013. Power factor was markedly better and would have appeared even more improved if 2013 data had excluded its first four months. The power factors became worse in 2014 as the utility appeared to conduct various reactive power management experiments and tests. The project could not discern for certain whether the changes to power factor were a passive byproduct of intentional voltage management, or whether the reactive power had been intentionally and independently controlled. Upon its review, Avista Utilities confirmed that voltage and reactive power could be independently controlled by its IVVC system, and that no data tag had been created for the times that the IVVC system had controlled reactive power.

The above observations about how power factor was managed hold similarly for nearly every Pullman feeder. Quartile plots are not offered for the other 12 feeders.

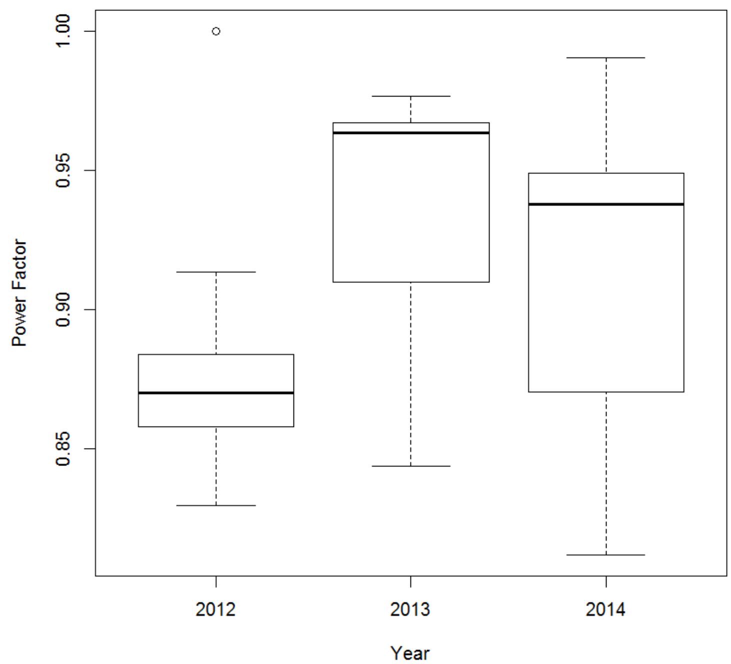


Figure 7.19. Quartile Distributions of Calculated Power Factor by Project Year for Turner Feeder 115. On this feeder, the reduction of power factor in Year 2014 is a pronounced example of what was observed for all Pullman site feeders.

Quartile plots like the example of Figure 7.20 were generated for the 13 Pullman site feeders. This plot compares the populations of the feeder's power factors when the voltage management had been reported to be inactive (false) against when it was reported to have been active (true). The power factors were improved when the voltage management indicator was active, but the differences are small.

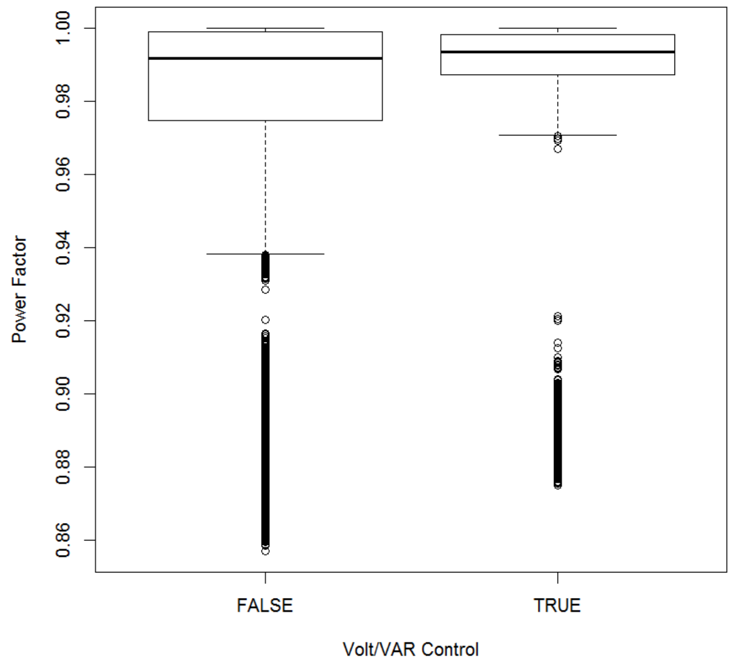
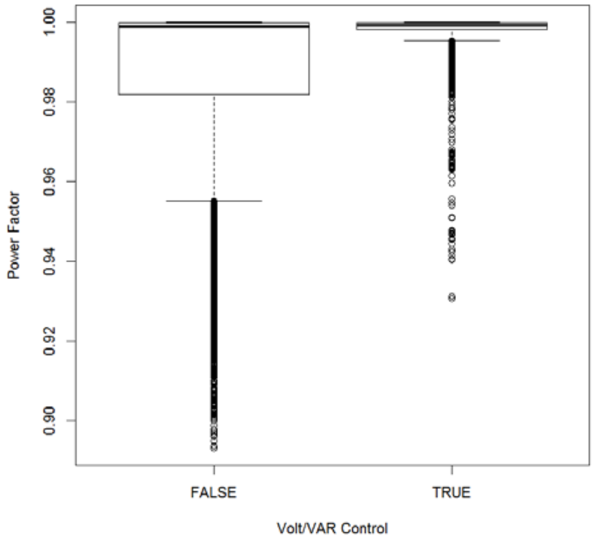
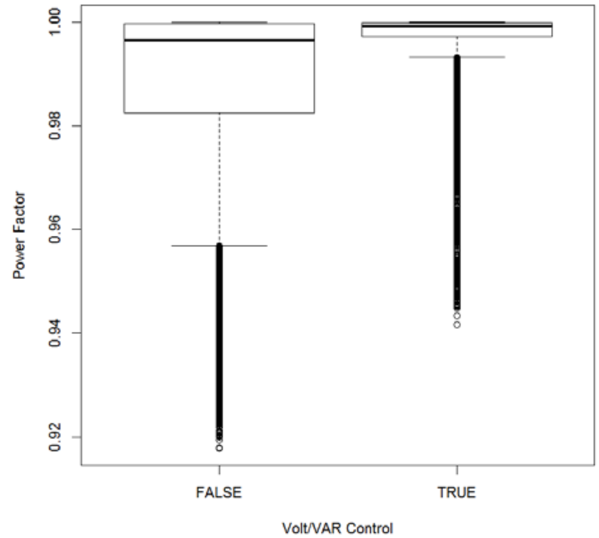


Figure 7.20. Quartile Distributions of Power Factor of Turner Feeder 111 when the IVVC System was Active (True) and Not (False)

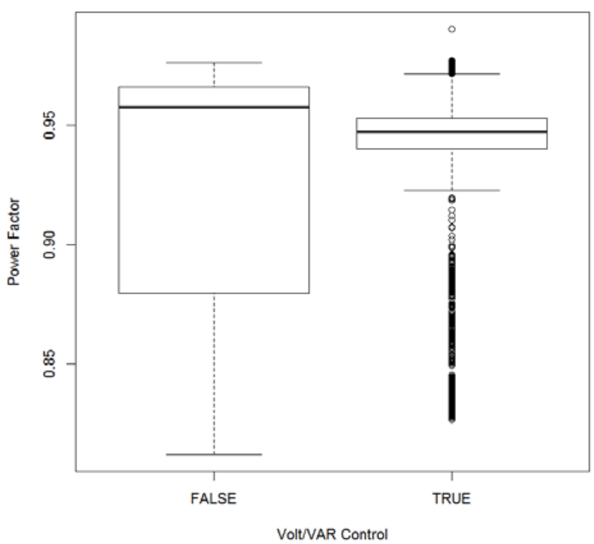
The quartile plots showing the change in power factors for the remaining 12 Pullman site feeders are shown in the panels of Figure 7.21. Small improvements are perhaps evident for all but three of the feeders. Virtually no improvement was evident at the two Terre View Feeders 131 and 132. The power factor at Turner Feeder 115 actually got worse at times the voltage was reported to be managed.



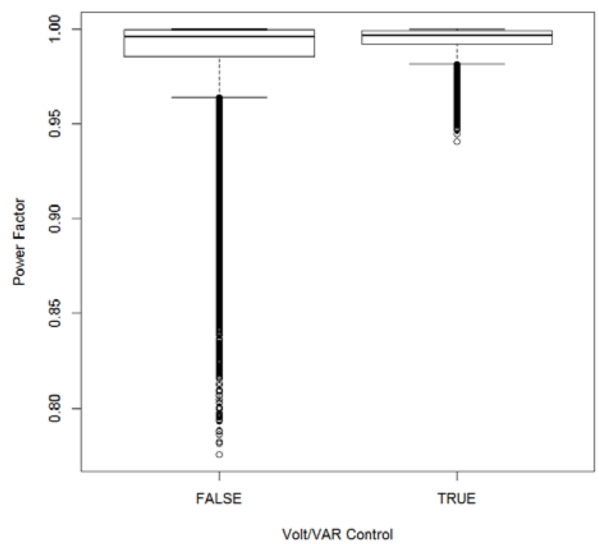
(a) Turner Feeder 112



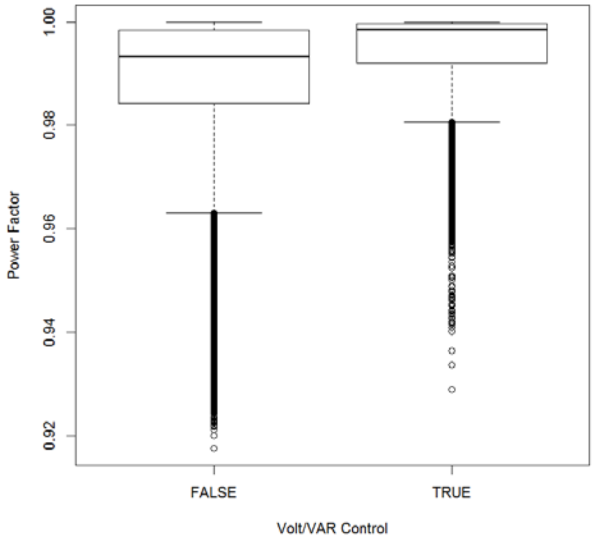
(b) Turner Feeder 113



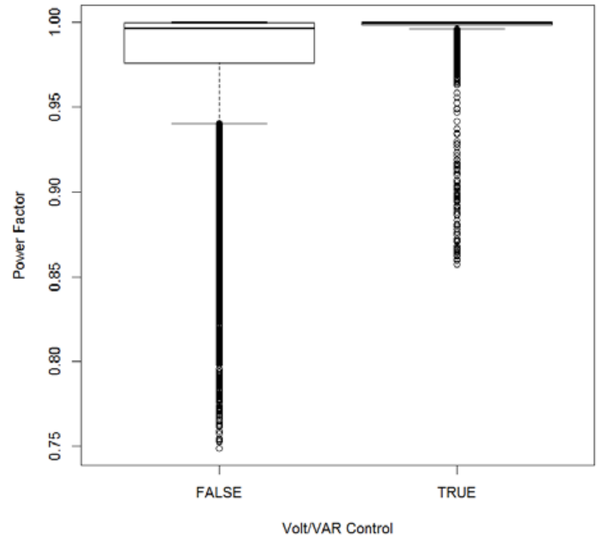
(c) Turner Feeder 115



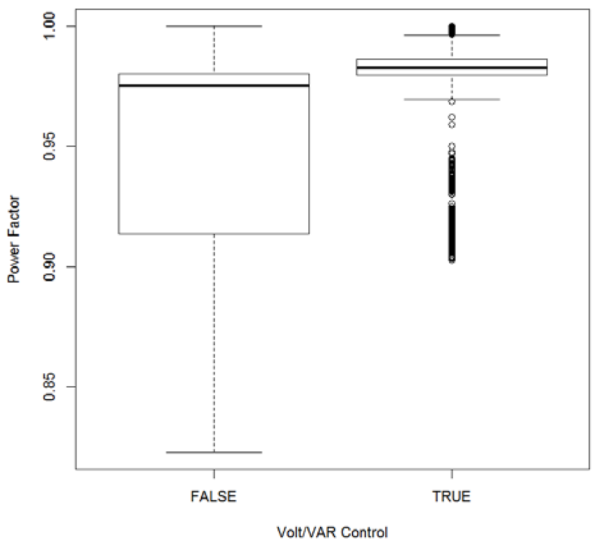
(d) Turner Feeder 116



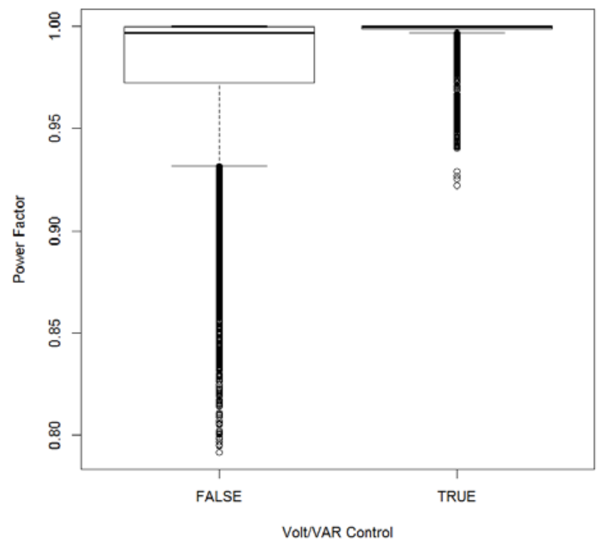
(e) Turner Feeder 117



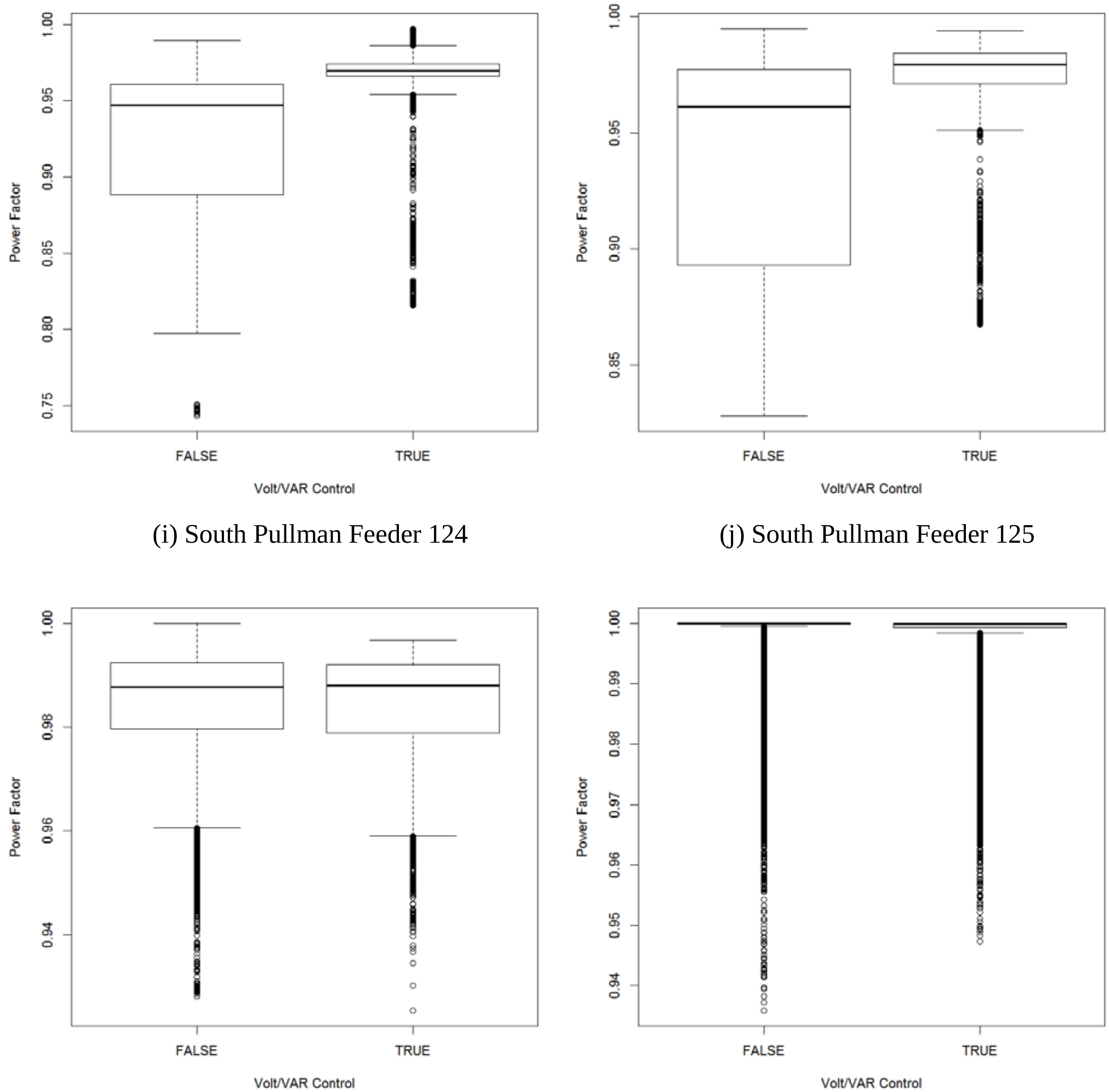
(f) South Pullman Feeder 121



(g) South Pullman Feeder 122



(h) South Pullman Feeder 123



(i) South Pullman Feeder 124

(j) South Pullman Feeder 125

(k) Terre View Feeder 131

(l) Terre View Feeder 132

Figure 7.21. Quartile Distributions of Power Factor of Pullman, Washington, Feeders when the Feeder's IVVC System was Active (True) and Not (False)

Project analysts devised and completed three analysis methods to estimate the seasonal, weekday and weekend impacts of voltage management on the Pullman feeders. A data period from September 1, 2013, through August 31, 2014, was used for each method. Because this is an IVVC system, the individual power impacts from voltage and VAr (or power factor) management cannot be fully separated. The results of analysis are likely to exceed the conservation that is normally available from voltage management alone (i.e., conservation voltage reduction, or CVR).

Method 1 directly compared consumption when voltage management was reported against that when the system was not reported to be under voltage management. This method was not temperature corrected. Temperature correction may not be essential when long periods of day-on/day-off testing are conducted. No regression methods were used. Average consumption during reported voltage management was simply compared against that of normal periods. Separate assessments were made for each season by weekend and weekday.

Method 2 was similar to Method 1, but it employed temperature correction and used regression methods. The fit was made to season, local hour of day, weekday type, and all permutations of these variables with ambient temperature. Additional parameters were introduced for all permutations of the voltage-control status with season and weekday type. R software was used for the linear regression (R Core Team 2013). The regression fit's coefficients that included the status of the voltage management system were reported as analysis results.

Method 3 may be novel. First, both voltage and distribution power each month were normalized by subtracting the month's average value and then dividing by the average. A linear regression was then conducted to model the normalized, relative power as a linear function of all the permutations of season, hour of day, and weekday type with ambient temperature. Additional variables were defined for the permutations of season, weekday type, and normalized voltage. As was the case for Method 2, the coefficients of the fit produced using regression in R software were reported for the parameters that included the status of the voltage management system. A principal advantage of Method 3 is that it directly yields the CVR factor as the coefficient of the term that was applied to the relative voltage change. That is, these terms state change in relative power or energy as a function of change in relative voltage. This method was found to be somewhat robust even when voltage management status was inaccurately reported and when irregular test periods occurred, whereas Methods 1 and 2 became less trustworthy and yielded wilder estimates when day-on/day-off tests were not used.

An interesting interplay was expected with Method 3 between the impacts of intentional voltage management and passive voltage management. The CVR impact is expected where different voltages were intentionally applied, and power is expected to have some proportionality to the applied voltage. However, a natural fluctuation in voltage might accompany changes in load in passive systems. In this case, voltage drops increase across distribution lines and transformers as load rises, which has a downward influence on voltage. These two potential impacts are contrary. Feeders that are not conducting intentional voltage management might, therefore, exhibit negative CVR coefficients.

An emerging protocol for assessing CVR impacts is available from the Regional Technical Forum, a subcommittee of the Northwest Power and Conservation Council (Regional Technical Forum 2015). None of the three methods are claimed to strictly follow that protocol.

Table 7.3 lists the findings for the 13 Pullman site feeders using novel Method 3. The analysis was conducted separately for weekdays and weekend days. This table combines the impacts from all four seasons. The columns include the difference between median relative voltages when voltage management was reported active and not (ΔV), the product of CVR factor and the difference of median voltages (ΔP), the CVR factor itself, and the change in energy that season and weekday type calculated as though voltage management been continuous (ΔE).

The calculated CVR factors and relative changes in power are larger and more dramatic at feeders that had little or no change in voltage. Increased voltage was observed at South Pullman Feeder 122 when voltage management was reported, which affected the signs of the changes in power and energy. Interestingly, Method 3 ignored the anomalous changes in voltage with system status and still calculated a credible CVR factor for that feeder.

The project determined that the total load of the Pullman feeders during September 1, 2013, through August 31, 2014, was about 375 GWh. Of this total, 273 GWh was consumed on weekdays, and 102 GWh was consumed on weekend days. The sum of the weekday conservation from Table 7.3 was 6.53 GWh per year for weekdays, and conservation for weekend days was 1.26 GWh per year. These constitute an estimated total conservation of 7.79 GWh per year if IVVC were practiced throughout the year as it was demonstrated intermittently on all the Pullman feeders. The calculated conservation was about 2.1% of total load, just a little less than Avista Utilities' prediction of 1.85%.

Table 7.3. Summary of Estimated Volt/VAr Management Impacts using Method 3

	Weekdays				Weekends			
Feeder	ΔV (%)	ΔP (%)	CVR Factor	ΔE (MWh/y)	ΔV (%)	ΔP (%)	CVR Factor	ΔE (MWh/y)
TUR111	−1.23	−1.9	1.5	−378	−1.11	−1.2	1.0	−84
TUR112	−0.29	−1.7	5.9	−369	−0.38	−3.5	9.2	−306
TUR113	−2.74	−3.5	1.3	−616	−2.69	−1.1	0.4	−78
TUR115	−0.19	−1.1	5.8	−260	−0.14	−0.6	4.4	−52
TUR116	−2.46	−2.7	1.1	−540	−2.46	−1.5	0.6	−123
TUR117	−2.30	−2.7	1.2	−782	−2.38	−0.2	0.1	−19
SPU121	−1.95	−2.7	1.4	−626	−2.01	0.0	−0.0	2
SPU122	0.38	1.3	3.5	327	0.38	1.1	2.8	102
SPU123	−2.55	−1.9	0.7	−469	−2.56	−0.2	0.1	−20
SPU124	−0.38	−1.9	5.1	−431	−0.38	−1.1	3.0	−90
SPU125	−0.85	−7.6	8.9	−1682	−0.81	−4.0	4.9	−308
TVW131	−1.21	−5.1	4.2	−617	−1.24	−7.4	6.0	−344
TVW132	−1.84	−0.8	0.4	−85	−1.83	1.3	−0.7	58

MWh = megawatt hour

Much more detail is supplied in Table 7.4 for impacts from individual seasons, weekdays, and feeders. This table includes analysis results from all three analysis methods that were applied by the project. Sub-tables were created for each feeder.

The first five rows of each sub-table list some general measurements and metrics that were useful. The first row ($P_{avg.}$) is the average power during the given season and weekday type. The second row ("DODO") is a metric devised by the project to indicate how closely the utility had adhered to a strict day-on/day-off regimen during the season on that feeder. First, each day was alternately given a value of either 1 or −1. Next, the applied values were added for days on which voltage management was active and not active for the given season. Finally, the magnitude of that difference was divided by the sum calculated as though all the days had been given the value 1.0. The formula for the new metric is given in Eq. 7.1.

$$DODO = \frac{\left| \sum_{active} \{1.0, -1.0\} - \sum_{normal} \{1.0, -1.0\} \right|}{\sum_{active} 1.0 + \sum_{normal} 1.0} \qquad \text{Eq. 7.1}$$

If voltage management were randomly applied, or if voltage management were never applied, the value of the new DODO metric would be about zero. If alternate days were strictly designated for voltage management, the metric would be near unity. Because Avista Utilities did most of its day-on/day-off testing in spring 2014, the metric is high in the spring season. This metric is potentially important because less robust methods like Methods 1 and 2 will perform better when this metric is near unity.

The metric row ΔT indicates the average difference between ambient temperatures when voltage management was reported and not reported for the given season and day type. Positive values mean that the temperature tended to be higher during voltage management. Negative values mean the temperatures were higher without voltage management. If voltage management periods were fairly or randomly applied during the period, the difference between the average temperatures would be small. Also, if the temperatures were similar, less sophisticated analysis methods might be valid. If the temperatures were different, then temperature correction was more critical and necessary for the analysis.

The fourth row states the average per-unit voltage ($V_{avg.}$) for the given season and day type while voltage management was not being applied. That is, this is a representation of normal voltage without voltage management. The fifth row states the difference between median voltages when voltage management is being applied and not (ΔV). As stated earlier, these voltages are based on average distribution phase voltages. The end-of-line voltages were not found to have been consistently measured and calibrated.

For both Methods 1 and 2, the change in average power was directly calculated, and the CVR factors and projected energy impacts were calculated from the change in average power using the differences in median voltages and the sums of hours of each season and day type. Method 3 directly calculated CVR factor, and the change in average power and energy were then calculated based on the difference in median voltage and numbers of each type of hour each season and day type.

Table 7.4. Summary of Feeder CVR Metrics

		Winter		Spring		Summer		Fall		All Seasons	
		M–F	S–S	M–F	S–S	M–F	S–S	M–F	S–S	M–F	S–S
Feeder TUR111	$P_{avg.}$ (kW)	3,602	3,270	3,085	2,807	2,918	2,635	3,193	2,873	3,220	2,911
	DODO	0.56	0.63	0.93	0.92	0.41	0.36	0.03	0.08	0.48	0.50
	ΔT (°F)	2.9	2.2	−0.7	−2.6	1.4	−0.5	−9.1	-	4.6	2.9
	$V_{avg.}$ (p.u.)	1.099	1.096	1.097	1.096	1.097	1.096	1.097	1.095	1.097	1.095
	ΔV (%)	−1.41	−1.13	−1.17	−1.14	−1.23	−1.24	−0.55	-	−1.23	−1.11
						**** Method #1 ****					
	ΔP (%)	−4.0	−1.7	-0.6	−0.9	1.3	1.1	10.6	-	−2.6	−2.6
	CVR Fact.	2.8	1.5	0.5	0.8	−1.1	−0.9	−19.2	-	2.2	2.3
	ΔE (MWh)	−225	−32	−29	−17	59	19	526	-	−530	−191
						**** Method #2 ****					
	ΔP (%)	−3.5 ± 0.1	−1.3 ± 0.7	−0.6 ± 0.1	−0.7 ± 0.8	1.2 ± 0.1	0.8 ± 1.0	−5.8 ± 0.4	-	−1.0 ± 0.0	−0.2 ± 0.1
	CVR Fact.	2.5 ± 0.1	1.2 ± 0.6	0.5 ± 0.1	0.6 ± 0.7	−1.0 ± 0.1	−0.7 ± 0.8	10.6 ± 0.6	-	0.8 ± 0.0	0.2 ± 0.1
	ΔE (MWh)	−196 ± 4	−26 ± 13	−28 ± 3	−13 ± 14	54 ± 3	14 ± 16	−289 ± 17	-	−205 ± 8	−17 ± 5
						**** Method #3 ****					
	ΔP (%)	−4.9 ± 0.1	−2.8 ± 0.1	−1.6 ± 0.1	−1.0 ± 0.1	0.8 ± 0.1	0.2 ± 0.1	−1.9 ± 0.1	-	−1.9 ± 0.0	−1.2 ± 0.1
	CVR Fact.	3.5 ± 0.1	2.5 ± 0.1	1.4 ± 0.1	0.9 ± 0.1	−0.6 ± 0.1	−0.2 ± 0.1	3.5 ± 0.1	2.5 ± 0.2	1.5 ± 0.0	1.0 ± 0.1
	ΔE (MWh)	−273 ± 4	−54 ± 2	−76 ± 3	−18 ± 2	34 ± 3	3 ± 2	−97 ± 3	-	−378 ± 8	−84 ± 4
Feeder TUR112	$P_{avg.}$ (kW)	4,428	4,516	3,054	3,129	2,786	2,739	3,259	3,247	3,475	3,486
	DODO	0.02	0.04	0.04	0.04	0.41	0.36	0.02	0.08	0.12	0.13
	ΔT (°F)	5.7	-	5.8	−0.2	1.4	−0.5	-	-	22.2	20.9
	$V_{avg.}$ (p.u.)	1.102	1.101	1.097	1.097	1.095	1.095	1.097	1.096	1.098	1.097
	ΔV (%)	0.16	-	−2.32	−0.11	0.03	−0.21	-	-	−0.29	−0.38
						**** Method #1 ****					
	ΔP (%)	−2.4	-	−16.0	−21.4	3.7	−2.3	-	-	−17.3	−23.2
	CVR Fact.	−15.1	-	6.9	194.7	124.7	10.8	-	-	59.5	61.1
	ΔE (MWh)	−166	-	−762	−434	163	-40	-	-	−3743	−2039
						**** Method #2 ****					
	ΔP (%)	−4.7 ± 6.7	-	4.7 ± 0.4	−20.8 ± 9.5	0.2 ± 0.1	−1.4 ± 1.6	-	-	0.6 ± 0.1	−1.3 ± 0.2
	CVR Fact.	−29 ± 42	-	−2.0 ± 0.2	190 ± 90	5.3 ± 4.7	6.5 ± 7.6	-	-	−2.1 ± 0.5	3.4 ± 0.6
	ΔE (MWh)	−330 ± 460	-	225 ± 20	−420 ± 190	7 ± 6	−24 ± 28	-	-	132 ± 28	−114 ± 19
						**** Method #3 ****					
	ΔP (%)	1.5 ± 0.0	-	−1.1 ± 0.4	−1.0 ± 0.0	0.3 ± 0.0	−1.7 ± 0.1	-	-	−1.7 ± 0.0	−3.5 ± 0.1
	CVR Fact.	9.4 ± 0.3	9.9 ± 0.4	0.5 ± 0.2	9.1 ± 0.4	9.5 ± 0.2	8.1 ± 0.3	9.0 ± 0.2	10.8 ± 0.4	5.9 ± 0.1	9.2 ± 0.2
	ΔE (MWh)	104 ± 3	-	−53 ± 19	−20 ± 1	13 ± 0	−30 ± 1	-	-	−369 ± 7	−306 ± 6

Table 7.4. (cont.)

		Winter		Spring		Summer		Fall		All Seasons	
		M–F	S–S	M–F	S–S	M–F	S–S	M–F	S–S	M–F	S–S
Feeder TUR113	$P_{avg.}$ (kW)	3,832	3,595	2,611	2,512	1,840	1,726	2,928	2,812	2,835	2,729
	DODO	0.61	0.61	0.92	0.92	0.41	0.36	0.02	0.08	0.49	0.49
	ΔT (°F)	0	0.2	-0.6	−2.6	1.4	−0.5	−16.3	−22.4	−0.3	0.4
	$V_{avg.}$ (p.u.)	1.100	1.098	1.096	1.095	1.092	1.092	1.096	1.095	1.096	1.095
	ΔV (%)	−2.81	−2.61	−2.71	−2.67	−2.63	−2.72	−2.54	−2.57	−2.74	−2.69
	**** Method #1 ****										
	ΔP (%)	−3.1	6.9	−1.4	1.9	4.6	2.8	17.3	9.9	−1.9	−4.3
	CVR Fact.	1.1	−2.7	0.5	−0.7	−1.7	−1.0	−6.8	−3.8	0.7	1.6
	ΔE (MWh)	−184	150	−55	30	131	31	788	173	−331	−295
	**** Method #2 ****										
	ΔP (%)	−3.1 ± 0.2	4.7 ± 1.5	−2.6 ± 0.2	−0.5 ± 1.8	2.7 ± 0.2	3.1 ± 2.5	2.6 ± 0.4	-	−0.6 ± 0.1	2.3 ± 0.2
	CVR Fact.	1.1 ± 0.1	−1.8 ± 0.6	0.9 ± 0.1	0.2 ± 0.7	−1.0 ± 0.1	−1.1 ± 0.9	−1.0 ± 0.1	-	0.2 ± 0.0	−0.8 ± 0.1
	ΔE (MWh)	−184 ± 13	101 ± 31	−104 ± 9	−9 ± 29	77 ± 6	34 ± 27	118 ± 16	-	−108 ± 21	156 ± 13
	**** Method #3 ****										
	ΔP (%)	−7.0 ± 0.2	−0.5 ± 0.3	−5.3 ± 0.2	−2.0 ± 0.3	1.8 ± 0.2	1.9 ± 0.3	−2.0 ± 0.3	−9.6 ± 0.6	−3.5 ± 0.1	−1.1 ± 0.2
	CVR Fact.	2.5 ± 0.1	0.2 ± 0.1	2.0 ± 0.1	0.8 ± 0.1	−0.7 ± 0.1	−0.7 ± 0.1	0.8 ± 0.1	3.7 ± 0.2	1.3 ± 0.0	0.4 ± 0.1
	ΔE (MWh)	−417 ± 12	−11 ± 7	−215 ± 8	−33 ± 5	51 ± 6	21 ± 4	−92 ± 14	−168 ± 10	−616 ± 19	−78 ± 13
Feeder TUR115	$P_{avg.}$ (kW)	3,940	3,433	3,823	3,372	3,748	3,341	3,629	3,234	3,759	3,330
	DODO	0.54	0.63	0.88	0.92	0.41	0.36	0.02	0.08	0.46	0.5
	ΔT (°F)	2.8	2.2	−0.9	−2.6	1.4	−0.5	−9.2	-	4.2	2.9
	$V_{avg.}$ (p.u.)	1.102	1.099	1.103	1.101	1.102	1.101	1.101	1.098	1.102	1.100
	ΔV (%)	−0.41	−0.17	−0.31	−0.26	−0.11	−0.27	−0.07	-	−0.19	−0.14
	**** Method #1 ****										
	ΔP (%)	−5.6	−3.3	−1.2	0.6	1.6	0.8	18.9	-	0.4	1.1
	CVR Fact.	13.8	19.2	3.8	−2.2	−14.3	−3.1	−269.4	-	−1.8	−7.9
	ΔE (MWh)	−347	−67	−70	13	92	18	1068	-	82	92
	**** Method #2 ****										
	ΔP (%)	−4.9 ± 0.1	−1.1 ± 6.3	−0.7 ± 0.1	0.2 ± 6.3	1.1 ± 0.1	0.5 ± 6.3	7.4 ± 4.4	-	−1.4 ± 0.1	0.2 ± 0.1
	CVR Fact.	11.9 ± 0.2	7 ± 37	2.2 ± 0.3	−1 ± 24	−9.6 ± 0.8	−2 ± 23	v106 ± 63	-	7.4 ± 0.3	−1.1 ± 0.6
	ΔE (MWh)	−299 ± 6	−20 ± 130	−41 ± 5	0 ± 140	62 ± 5	10 ± 140	420 ± 250	-	−331 ± 14	13 ± 8
	**** Method #3 ****										
	ΔP (%)	−3.9 ± 0.1	−1.6 ± 0.0	−1.1 ± 0.0	−0.4 ± 0.1	−0.4 ± 0.0	−0.3 ± 0.1	−0.3 ± 0.0	-	−1.1 ± 0.0	−0.6 ± 0.0
	CVR Fact.	9.5 ± 0.1	9.6 ± 0.2	3.6 ± 0.1	1.5 ± 0.2	3.7 ± 0.2	1.2 ± 0.2	4 .0 ± 0.2	4.9 ± 0.2	5.8 ± 0.1	4.4 ± 0.1
	ΔE (MWh)	−238 ± 3	−34 ± 1	−66 ± 2	−9 ± 1	−24 ± 1	−7 ± 1	−16 ± 1	-	−260 ± 2	−52 ± 2

Table 7.4. (cont.)

Feeder		Winter		Spring		Summer		Fall		All Seasons	
		M–F	S–S	M–F	S–S	M–F	S–S	M–F	S–S	M–F	S–S
Feeder TUR116	$P_{avg.}$ (kW)	4,348	4,338	2,959	2,949	2,616	2,605	3,034	3,003	3,231	3,243
	DODO	0.61	0.61	0.89	0.92	0.41	0.36	0.02	0.00	0.48	0.47
	ΔT (°F)	−0.1	0.2	−1.4	−2.6	1.4	-0.5	−9.7	−6.5	0.5	1.4
	$V_{avg.}$ (p.u.)	1.102	1.101	1.097	1.097	1.094	1.095	1.096	1.095	1.097	1.097
	ΔV (%)	−2.57	−2.44	−2.56	−2.48	−2.39	−2.53	−2.11	−2.32	−2.46	−2.46
						**** Method #1 ****					
	ΔP (%)	−2.7	−1.2	−0.2	0.5	1.2	−5.3	24.0	19.1	1.9	−3.6
	CVR Fact.	1.0	0.5	0.1	−0.2	−0.5	2.1	−11.4	−8.2	−0.8	1.5
	ΔE (MWh)	−180	−31	−11	10	50	−89	1135	358	379	−294
						**** Method #2 ****					
	ΔP (%)	−3.2 ± 0.1	2.3 ± 1.0	−1.2 ± 0.1	−1.7 ± 1.2	−2.4 ± 0.1	−4.4 ± 1.6	7.0 ± 0.2	-	−1.0 ± 0.1	0.1 ± 0.1
	CVR Fact.	1.2 ± 0.1	−-0.9 ± 0.4	0.5 ± 0.1	0.6 ± 0.5	1.0 ± 0.1	1.7 ± 0.6	−3.3 ± 0.1	-	0.4 ± 0.0	−0.0 ± 0.1
	ΔE (MWh)	−216 ± 9	60 ± 26	−55 ± 6	−32 ± 23	−96 ± 6	−74 ± 27	330 ± 9	-	−210 ± 16	7 ± 10
						**** Method #3 ****					
	ΔP (%)	−4.2 ± 0.1	0.9 ± 0.2	−3.2 ± 0.1	−1.4 ± 0.2	−3.7 ± 0.1	−5.6 ± 0.2	3.5 ± 0.2	3.5 ± 0.3	−2.7 ± 0.1	−1.5 ± 0.1
	CVR Fact.	1.6 ± 0.1	−0.4 ± 0.1	1.2 ± 0.1	0.6 ± 0.1	1.6 ± 0.1	2.2 ± 0.1	−1.7 ± 0.1	−1.5 ± 0.1	1.1 ± 0.0	0.6 ± 0.1
	ΔE (MWh)	−282 ± 9	22 ± 6	−146 ± 6	−27 ± 4	−151 ± 6	−94 ± 3	165 ± 9	65 ± 6	−540 ± 14	−123 ± 10
Feeder TUR117	$P_{avg.}$ (kW)	5,576	4,882	4,424	3,734	3,923	3,040	4,569	3,857	4,625	3,922
	DODO	0.61	0.61	0.90	0.92	0.41	0.36	0.03	0.08	0.48	0.49
	ΔT (°F)	0.0	0.3	−1.3	−2.6	1.4	−0.5	−13.9	−22.4	0.4	0.4
	$V_{avg.}$ (p.u.)	1.107	1.103	1.104	1.100	1.101	1.098	1.103	1.099	1.103	1.100
	ΔV (%)	−2.48	−2.37	−2.38	−2.43	−2.08	−2.40	−2.19	−2.22	−2.30	−2.38
						**** Method #1 ****					
	ΔP (%)	−1.2	4.9	−1.3	1.0	3.1	3.4	11.0	12.4	0.5	−1.2
	CVR Fact.	0.5	−2.1	0.5	−0.4	−1.5	−1.4	−5.0	−5.6	−0.2	0.5
	ΔE (MWh)	−102	144	−88	24	189	67	782	299	144	−115
						**** Method #2 ****					
	ΔP (%)	−0.9 ± 0.1	2.6 ± 1.0	−2.4 ± 0.1	−0.8 ± 1.2	1.3 ± 0.1	2.5 ± 1.6	−1.5 ± 0.3	-	−0.7 ± 0.1	1.5 ± 0.1
	CVR Fact.	0.4 ± 0.1	−1.1 ± 0.4	1.0 ± 0.1	0.3 ± 0.5	−0.6 ± 0.1	−1.0 ± 0.7	0.7 ± 0.1	-	0.3 ± 0.0	−0.6 ± 0.1
	ΔE (MWh)	−75 ± 11	76 ± 28	−162 ± 10	−20 ± 28	79 ± 8	49 ± 31	−107 ± 19	-	−211 ± 23	151 ± 12
						**** Method #3 ****					
	ΔP (%)	−3.1 ± 0.1	−0.1 ± 0.2	−3.8 ± 0.1	−0.7 ± 0.2	0.1 ± 0.1	1.4 ± 0.2	−6.9 ± 0.2	−4.1 ± 0.4	−2.7 ± 0.1	−0.2 ± 0.1
	CVR Fact.	1.2 ± 0.1	0.0 ± 0.1	1.6 ± 0.1	0.3 ± 0.1	−0.1 ± 0.1	−0.6 ± 0.1	3.1 ± 0.1	1.8 ± 0.2	1.2 ± 0.0	0.1 ± 0.1
	ΔE (MWh)	−265 ± 10	−2 ± 6	−263 ± 8	−18 ± 5	7 ± 7	28 ± 4	−488 ± 16	−98 ± 9	−782 ± 20	−19 ± 12

Table 7.4. (cont.)

Feeder		Winter M–F	Winter S–S	Spring M–F	Spring S–S	Summer M–F	Summer S–S	Fall M–F	Fall S–S	All Seasons M–F	All Seasons S–S
Feeder SPU121	$P_{avg.}$ (kW)	4,676	4,690	3,259	3,156	3,317	2,838	3,574	3,336	3,673	3,496
	DODO	0.61	0.61	0.93	0.92	0.41	0.36	0.02	0.08	0.49	0.49
	ΔT (°F)	0.6	3.0	−0.7	−2.6	1.1	−0.5	−13.4	−22.4	−0.2	-0.5
	$V_{avg.}$ (p.u.)	1.090	1.090	1.091	1.090	1.089	1.091	1.089	1.088	1.090	1.089
	ΔV (%)	−1.91	−1.85	−2.17	−2.09	−1.91	−2.28	−1.70	−1.79	−1.95	−2.01
	**** Method #1 ****										
	ΔP (%)	−1.8	−3.9	−1.4	−0.0	1.0	−2.0	17.4	31.0	2.3	−1.4
	CVR Fact.	0.9	2.1	0.6	0.0	−0.5	0.9	−10.2	−17.3	−1.2	0.7
	ΔE (MWh)	−130	−109	−70	−1	52	−36	970	646	525	−122
	**** Method #2 ****										
	ΔP (%)	−2.8 ± 0.2	1.9 ± 1.0	−1.7 ± 0.2	−2.0 ± 1.3	−0.6 ± 0.1	−0.8 ± 1.7	0.8 ± 0.3	-	−1.6 ± 0.1	1.0 ± 0.1
	CVR Fact.	1.5 ± 0.1	−1.0 ± 0.6	0.8 ± 0.1	0.9 ± 0.6	0.3 ± 0.1	0.3 ± 0.8	−0.5 ± 0.2	-	0.8 ± 0.0	−0.5 ± 0.1
	ΔE (MWh)	−207 ± 11	53 ± 29	−88 ± 8	−40 ± 26	−28 ± 7	−14 ± 31	42 ± 15	-	−355 ± 18	88 ± 11
	**** Method #3 ****										
	ΔP (%)	−3.2 ± 0.2	0.3 ± 0.2	−3.2 ± 0.2	−0.1 ± 0.2	−3.2 ± 0.1	−1.1 ± 0.2	1.6 ± 0.2	5.4 ± 0.4	−2.7 ± 0.1	0.0 ± 0.1
	CVR Fact.	1.7 ± 0.1	−0.1 ± 0.1	1.5 ± 0.1	0.1 ± 0.1	1.7 ± 0.1	0.5 ± 0.1	−0.9 ± 0.1	−3.0 ± 0.2	1.4 ± 0.0	−0.0 ± 0.1
	ΔE (MWh)	−233 ± 11	7 ± 6	−164 ± 8	−3 ± 4	−167 ± 7	−20 ± 4	87 ± 12	113 ± 8	−626 ± 18	2 ± 11
Feeder SPU122	$P_{avg.}$ (kW)	4,355	4,218	3,788	3,629	3,610	3,413	4,014	3,891	3,976	3,827
	DODO	0.55	0.63	0.92	0.92	0.40	0.36	0.02	0.08	0.47	0.50
	ΔT (°F)	2.4	2.2	−0.9	−2.6	1.5	−0.5	-	-	4.3	2.9
	$V_{avg.}$ (p.u.)	1.100	1.098	1.101	1.100	1.097	1.097	1.097	1.096	1.098	1.098
	ΔV (%)	0.23	0.32	0.13	0.23	0.53	0.40	-	-	0.38	0.38
	**** Method #1 ****										
	ΔP (%)	−1.5	−0.7	−0.5	0.9	1.2	−0.4	-	-	−2.7	−3.9
	CVR Fact.	−6.4	−2.3	−3.7	4.0	2.3	−0.9	-	-	−7.1	−10.2
	ΔE (MWh)	−99	−18	−28	22	69	−8	-	-	−670	−372
	**** Method #2 ****										
	ΔP (%)	−0.9 ± 0.1	0.8 ± 0.8	−0.5 ± 0.1	0.4 ± 1.0	1.1 ± 0.1	−0.8 ± 1.3	-	-	−0.1 ± 0.1	0.1 ± 0.1
	CVR Fact.	−3.7 ± 0.5	2.5 ± 2.4	−4.1 ± 0.9	1.9 ± 4.2	2.2 ± 0.2	−2.0 ± 3.3	-	-	−0.2 ± 0.2	0.3 ± 0.3
	ΔE (MWh)	−58 ± 8	20 ± 20	−31 ± 7	10 ± 23	64 ± 7	−18 ± 29	-	-	−17 ± 17	12 ± 11
	**** Method #3 ****										
	ΔP (%)	0.3 ± 0.0	0.4 ± 0.1	0.3 ± 0.0	0.7 ± 0.1	2.0 ± 0.1	0.2 ± 0.1	-	-	1.3 ± 0.0	1.1 ± 0.1
	CVR Fact.	1.3 ± 0.1	1.2 ± 0.3	2.5 ± 0.2	3.0 ± 0.3	3.8 ± 0.1	0.5 ± 0.2	6.8 ± 0.2	7.7 ± 0.3	3.5 ± 0.1	2.8 ± 0.1
	ΔE (MWh)	20 ± 2	9 ± 2	19 ± 1	16 ± 1	112 ± 3	5 ± 2	-	-	327 ± 7	102 ± 5

Table 7.4. (cont.)

		Winter		Spring		Summer		Fall		All Seasons	
		M–F	S–S	M–F	S–S	M–F	S–S	M–F	S–S	M–F	S–S
Feeder SPU123	$P_{avg.}$ (kW)	4,690	4,605	3,748	3,644	3,967	3,727	3,921	3,762	4,043	3,907
	DODO	0.61	0.61	0.93	0.92	0.36	0.29	0.02	0.08	0.48	0.47
	ΔT (°F)	0.6	3.0	−0.7	−2.6	1.0	−0.1	−13.4	−22.4	−1.2	−2.5
	$V_{avg.}$ (p.u.)	1.101	1.100	1.100	1.099	1.096	1.094	1.097	1.096	1.098	1.097
	ΔV (%)	−2.64	−2.56	−2.75	−2.72	−2.50	−2.54	−2.26	−2.19	−2.55	−2.56
	**** Method #1 ****										
	ΔP (%)	−2.2	−2.7	−1.3	−2.3	0.1	−1.3	13.1	16.6	1.9	0.1
	CVR Fact.	0.8	1.1	0.5	0.9	−0.0	0.5	−5.8	−7.6	−0.8	−0.0
	ΔE (MWh)	−162	−75	−78	−55	7	−32	802	390	479	8
	**** Method #2 ****										
	ΔP (%)	−2.7 ± 0.1	0.6 ± 0.7	−1.5 ± 0.1	−2.4 ± 0.9	−1.5 ± 0.1	0.9 ± 1.2	4.1 ± 0.2	-	−1.4 ± 0.1	0.6 ± 0.1
	CVR Fact.	1.0 ± 0.0	−0.2 ± 0.3	0.6 ± 0.0	0.9 ± 0.3	0.6 ± 0.0	−0.3 ± 0.5	−1.8 ± 0.1	-	0.5 ± 0.0	−0.2 ± 0.0
	ΔE (MWh)	−194 ± 7	17 ± 20	−88 ± 6	−57 ± 21	−90 ± 6	21 ± 29	248 ± 12	-	−341 ± 15	59 ± 9
	**** Method #3 ****										
	ΔP (%)	−3.1 ± 0.1	−0.0 ± 0.2	−1.9 ± 0.1	−1.7 ± 0.2	−2.0 ± 0.1	0.2 ± 0.2	2.0 ± 0.2	4.4 ± 0.3	−1.9 ± 0.1	−0.2 ± 0.1
	CVR Fact.	1.2 ± 0.0	0.0 ± 0.1	0.7 ± 0.0	0.6 ± 0.1	0.8 ± 0.0	−0.1 ± 0.1	−0.9 ± 0.1	−2.0 ± 0.1	0.7 ± 0.0	0.1 ± 0.0
	ΔE (MWh)	−226 ± 8	−1 ± 4	−109 ± 6	−41 ± 4	−123 ± 6	5 ± 4	124 ± 10	103 ± 7	−469 ± 13	−20 ± 8
Feeder SPU124	$P_{avg.}$ (kW)	4,284	3,797	3,298	2,893	3,142	2,690	3,542	3,161	3,598	3,173
	DODO	0.57	0.63	0.92	0.92	0.42	0.36	0.01	0.08	0.48	0.50
	ΔT (°F)	2.4	2.2	−0.9	−2.6	1.8	−0.5	−1.9	-	4.5	2.9
	$V_{avg.}$ (p.u.)	1.102	1.100	1.099	1.097	1.099	1.097	1.099	1.097	1.099	1.098
	ΔV (%)	−0.61	−0.50	−0.29	−0.28	−0.30	−0.48	0.53	-	−0.38	−0.38
	**** Method #1 ****										
	ΔP (%)	−2.8	0.6	−1.4	0.0	1.1	−0.2	20.6	-	−3.5	−4.7
	CVR Fact.	4.6	−1.3	4.7	−0.0	−3.8	0.5	38.8	-	9.3	12.3
	ΔE (MWh)	−186	14	−70	0	55	−4	1136	-	−790	−373
	**** Method #2 ****										
	ΔP (%)	−2.8 ± 0.1	0.1 ± 3.6	−1.1 ± 0.1	−0.6 ± 3.6	−0.0 ± 0.1	−1.0 ± 3.7	−6.0 ± 2.5	-	−1.3 ± 0.1	−0.3 ± 0.1
	CVR Fact.	4.6 ± 0.2	−0.3 ± 7.2	3.6 ± 0.3	2.2 ± 1	0.1 ± 0.3	2.1 ± 7.8	−11.2 ± 4.8	-	3.5 ± 0.2	0.7 ± 0.2
	ΔE (MWh)	−189 ± 7	3 ± 82	−54 ± 5	−12 ± 68	−2 ± 5	−18 ± 65	−330 ± 140	-	−301 ± 13	−21 ± 7
	**** Method #3 ****										
	ΔP (%)	−3.5 ± 0.1	−0.7 ± 0.1	−2.0 ± 0.0	−1.4 ± 0.1	−0.6 ± 0.0	−1.2 ± 0.1	3.1 ± 0.1	-	−1.9 ± 0.0	−1.1 ± 0.0
	CVR Fact.	5.7 ± 0.1	1.4 ± 0.2	7.0 ± 0.1	4.9 ± 0.2	2.1 ± 0.1	2.4 ± 0.2	5.9 ± 0.2	4.6 ± 0.3	5.1 ± 0.1	3.0 ± 0.1
	ΔE (MWh)	−231 ± 5	−16 ± 2	−105 ± 2	−25 ± 1	−30 ± 2	−20 ± 2	171 ± 6	-	−431 ± 7	−90 ± 3

Table 7.4. (cont.)

		Winter		Spring		Summer		Fall		All Seasons	
		M–F	S–S	M–F	S–S	M–F	S–S	M–F	S–S	M–F	S–S
Feeder SPU125	$P_{avg.}$ (kW)	3,331	2,718	3,233	2,807	3,971	3,574	3,647	3,214	3,552	3,080
	DODO	0.55	0.63	0.91	0.92	0.40	0.36	0.02	0.08	0.47	0.50
	ΔT (°F)	3.1	2.2	−1.0	−2.6	1.6	−0.5	-	-	4.4	2.9
	$V_{avg.}$ (p.u.)	1.097	1.094	1.100	1.098	1.099	1.098	1.096	1.094	1.098	1.096
	ΔV (%)	−0.98	−0.8	−1.17	−1.16	−0.49	−0.67	-	-	−0.85	−0.81
	**** Method #1 ****										
	ΔP (%)	−7.8	7.0	−0.9	−0.3	5.2	3.9	-	-	−0.3	3.5
	CVR Fact.	8.0	−8.8	0.7	0.3	−10.6	−5.9	-	-	0.3	−4.3
	ΔE (MWh)	−405	114	−43	−5	320	91	-	-	−62	272
	**** Method #2 ****										
	ΔP (%)	−7.6 ± 0.2	5.0 ± 1.3	−0.4 ± 0.2	0.3 ± 1.6	0.5 ± 0.2	1.5 ± 2.3	-	-	−2.4 ± 0.1	2.4 ± 0.2
	CVR Fact.	7.7 ± 0.2	−6.2 ± 1.7	0.4 ± 0.2	−0.3 ± 1.4	−1.0 ± 0.4	−2.3 ± 3.4	-	-	2.8 ± 0.1	−2.9 ± 0.2
	ΔE (MWh)	−394 ± 11	81 ± 22	−21 ± 10	6 ± 29	31 ± 12	35 ± 53	-	-	−525 ± 27	182 ± 14
	**** Method #3 ****										
	ΔP (%)	−10.6 ± 0.2	−2.2 ± 0.2	−4.1 ± 0.2	−1.5 ± 0.2	−4.0 ± 0.1	−3.9 ± 0.2	-	-	−7.6 ± 0.1	−4.0 ± 0.1
	CVR Fact.	10.8 ± 0.2	2.7 ± 0.3	3.5 ± 0.1	1.3 ± 0.2	8.2 ± 0.2	5.8 ± 0.3	28.4 ± 0.3	24.6 ± 0.4	8.9 ± 0.1	4.9 ± 0.1
	ΔE (MWh)	−552 ± 8	−36 ± 3	−205 ± 8	−27 ± 4	−250 ± 6	−90 ± 4	-	-	−1682 ± 18	−308 ± 9
Feeder TVW131	$P_{avg.}$ (kW)	1,506	1,412	1,629	1,476	2,992	2,802	1,893	1,815	1,950	1,838
	DODO	0.56	0.57	0.68	0.64	0.41	0.36	0.03	0.08	0.42	0.41
	ΔT (°F)	3.0	1.2	−0.9	−1.2	1.5	−0.5	−12.2	-	4.0	2.8
	$V_{avg.}$ (p.u.)	1.086	1.085	1.087	1.086	1.093	1.092	1.090	1.090	1.089	1.088
	ΔV (%)	−1.56	−1.42	−1.11	−1.09	−1.37	−1.52	−0.72	-	−1.21	−1.24
	**** Method #1 ****										
	ΔP (%)	−1.1	0.6	−3.0	−9.9	6.1	−9.3	−20.2	-	10.7	−0.5
	CVR Fact.	0.7	−0.4	2.7	9.1	−4.4	6.1	28.0	-	−8.8	0.4
	ΔE (MWh)	−26	5	−77	−94	283	−169	−596	-	1301	−24
	**** Method #2 ****										
	ΔP (%)	−1.1 ± 0.4	−1.2 ± 2.8	−2.2 ± 0.3	−5.4 ± 3.1	−0.7 ± 0.3	−9.0 ± 4.1	12.0 ± 1.2	-	−1.0 ± 0.2	−5.3 ± 0.3
	CVR Fact.	0.7 ± 0.2	0.8 ± 1.9	2.0 ± 0.3	5.0 ± 2.9	0.5 ± 0.2	5.9 ± 2.7	−16.7 ± 1.7	-	0.9 ± 0.2	4.3 ± 0.2
	ΔE (MWh)	−25 ± 8	−10 ± 23	−56 ± 8	−52 ± 30	−33 ± 15	−163 ± 75	355 ± 36	-	−125 ± 23	−246 ± 14
	**** Method #3 ****										
	ΔP (%)	−2.2 ± 0.3	−0.4 ± 0.5	−4.4 ± 0.3	−6.2 ± 0.4	−7.1 ± 0.3	−11.9 ± 0.5	−13.1 ± 0.4	-	−5.1 ± 0.2	−7.4 ± 0.2
	CVR Fact.	1.4 ± 0.2	0.3 ± 0.4	4.0 ± 0.2	5.7 ± 0.3	5.2 ± 0.2	7.8 ± 0.3	18.2 ± 0.5	26.0 ± 0.8	4.2 ± 0.1	6.0 ± 0.2
	ΔE (MWh)	−51 ± 7	−4 ± 4	−113 ± 7	−59 ± 4	−332 ± 14	−216 ± 9	−386 ± 10	-	−617 ± 18	−344 ± 11

Table 7.4. (cont.)

		Winter		Spring		Summer		Fall		All Seasons	
		M–F	S–S	M–F	S–S	M–F	S–S	M–F	S–S	M–F	S–S
Feeder TVW132	$P_{avg.}$ (kW)	268	2,604	1,581	1,650	1,050	1,024	1,569	1,571	1,685	1,732
	DODO	0.60	0.63	0.67	0.64	0.41	0.36	0.04	0.08	0.43	0.43
	ΔT (°F)	−0.1	−0.6	−0.9	−1.2	1.5	−0.5	−14.9	−22.4	−0.3	0.5
	$V_{avg.}$ (p.u.)	1.084	1.084	1.085	1.084	1.086	1.086	1.087	1.087	1.086	1.086
	ΔV (%)	−1.45	−1.24	−1.81	−1.72	−2.09	−2.17	−1.64	−1.78	−1.84	−1.83
	**** Method #1 ****										
	ΔP (%)	1.2	5.6	0.6	2.3	3.4	2.9	28.8	35.5	5.1	−0.8
	CVR Fact.	−0.8	−4.5	−0.3	−1.3	−1.6	−1.3	−17.6	−19.9	−2.8	0.4
	ΔE (MWh)	48	88	14	24	55	19	704	349	538	−35
	**** Method #2 ****										
	ΔP (%)	−0.2 ± 0.2	5.3 ± 1.3	−1.2 ± 0.2	0.2 ± 1.5	2.0 ± 0.2	3.3 ± 2.1	−0.4 ± 0.3	-	0.1 ± 0.1	2.8 ± 0.2
	CVR Fact.	0.2 ± 0.1	−4.3 ± 1.0	0.7 ± 0.1	−0.1 ± 0.9	−1.0 ± 0.1	−1.5 ± 1.0	0.2 ± 0.2	-	−0.1 ± 0.1	−1.5 ± 0.1
	ΔE (MWh)	−9 ± 7	83 ± 20	−30 ± 4	2 ± 16	33 ± 3	22 ± 14	−9 ± 8	-	13 ± 11	123 ± 7
	**** Method #3 ****										
	ΔP (%)	−2.4 ± 0.1	2.6 ± 0.2	−0.3 ± 0.2	0.1 ± 0.2	1.5 ± 0.2	2.7± 0.3	−3.8 ± 0.3	−3.0 ± 0.5	−0.8 ± 0.1	1.3 ± 0.2
	CVR Fact.	1.6 ± 0.1	−2.1 ± 0.2	0.2 ± 0.1	−0.0 ± 0.1	−0.7 ± 0.1	−1.2 ± 0.1	2.3 ± 0.2	1.7 ± 0.3	0.4 ± 0.1	−0.7 ± 0.1
	ΔE (MWh)	−96 ± 5	41 ± 4	−8 ± 4	1 ± 3	24 ± 3	18 ± 2	−92 ± 6	−29 ± 5	−85 ± 9	58 ± 7

The impact of VAr management on the Pullman feeders was difficult to independently assess. Review of the calculated power factors in 2014 revealed that control was being intermittently engaged and then released. These periods were not perfectly correlated with the times that voltage had been managed (reduced). Therefore, the project concludes that VAr management was often engaged independently from voltage management. Regardless, the project used the only indicator available to it to estimate the impact of VAr management.

First the median power factors were calculated at times that the IVVC status indicator (a binary status that had been attributed to a condition of regulator tap settings for each feeder) was active and not. The poor correlation between this indicator and power factor means that the differences between the two calculated medians will be conservative. The results of these calculations have been listed in Table 7.5, where "before" indicates the times that the binary status was inferred to be in its normal condition, and "after" indicates what is inferred to be the state of active IVVC control. The inverse ratio of these power factors may be used to infer the impact of distribution line currents compared to the "before" status. The implication for line losses is the square of this ratio, because line losses are proportional to the square of the electrical current the lines conduct. The far right column of Table 7.5 states the change in inferred line losses compared to the "before" condition when VArs were not being actively controlled.

From this table, none of the power factors change greatly. The implications for relative line losses are small. Four of the feeders likely reduce line losses by 1% or more. The greatest estimated change shows a 4.6% reduction in line losses.

This comparison does not give the utility due credit for the static improvements that were apparently made in 2012. Refer back to Figure 7.19, for example, which shows the distributions of power factor in 2012, 2013, and 2014 for Turner Feeder 115. That example shows that the power factor was only about 0.87 during 2012, much lower than any of the power factors in Table 7.5. The power factor was increased to about 0.97 the following year. This improvement might have reduced electrical distribution currents by fully 10%, and distribution lines losses might have been reduced by 20%. These are valuable improvements. The project understands that, while valuable, the improvements should probably be attributed to static equipment updates and not the operations of the IVVC system.

Table 7.5. Summary of the Observed Changes in Power Factor and the Inferred Impacts from Power Factor Correction on the Pullman Feeders

	Power Factor		Current	Line Loss	Line Loss
Feeder	Before	After	Ratio	Ratio	Change (%)
TUR111	0.9918	0.9936	0.998	0.996	−0.359
TUR112	0.9988	0.9992	1.000	0.999	−0.091
TUR113	0.9965	0.9993	0.997	0.995	−0.544
TUR115	0.9577	0.9474	1.011	1.022	2.166
TUR116	0.9962	0.9969	0.999	0.998	−0.151
TUR117	0.9933	0.9986	0.995	0.990	−1.040
SPU121	0.9964	0.9995	0.997	0.994	−0.616
SPU122	0.9753	0.9827	0.992	0.985	−1.513
SPU123	0.9966	0.9995	0.997	0.994	−0.572
SPU124	0.9472	0.9699	0.977	0.954	−4.635
SPU125	0.9613	0.9794	0.981	0.963	−3.672
TVW131	0.9878	0.9880	1.000	0.999	−0.055
TVW132	1.0000	0.9999	1.000	1.000	0.026

Based on data received from Avista Utilities during the PNWSGD project, the project was able to observe active management of both voltage and reactive power on the Pullman site feeders. Voltages for many of the Pullman feeders were observed to have been periodically reduced by up to 2.7%. Many of the feeders revealed periods of day-on, day-off testing, especially through spring 2014, as was stipulated by the Regional Technical Forum simplified protocol for evaluation of CVR impacts (Regional Technical Forum 2015). The utility had contracted Navigant Consulting, Inc., to evaluate the performance of voltage management on these feeders, and the results of that evaluation had been in line with the utility’s projections.

The project also observed that site power factors were corrected significantly during early 2013, and power factors then varied with what the project infers to be the periodic engagement of IVVC.

The utility provided the project an indicator of a binary status of the regulator tap settings on the Pullman feeders. The project found very good correlation between this reported status and voltage magnitudes, where one status corresponded to normal voltages and the other corresponded to periods when the voltage had been measurably reduced. The correlation of this indicator was weaker for reactive power management. No independent indicator was found for times that VArs might have been managed at times different from voltage management.

The project used three methods to estimate the impacts of voltage management on these feeders. The first was similar to the Regional Technical Forum protocol using no temperature correction. The second was similar to the first in that it was based on discrete periods that the voltage had been reduced. The second method corrected for temperature impacts. The third was a continuous method that directly calculated seasonal CVR factor and required no reporting of discrete voltage management periods. All three methods worked adequately in seasons that day-on, day-off testing had been extensively used and when the changes in voltage had been great. The continuous method was found to be robust at other times when testing was irregular and when changes in voltage were small or had been perhaps reported erroneously. Even so, calculated impacts were highly variable with respect to methods, testing practices, data practices, season, feeder, and day type.

Using the third method, the project estimated that 2.1% of the Pullman electricity consumption might be conserved if the demonstrated IVVC control were applied continuously and across all 13 Pullman feeders. This estimate was near, but somewhat exceeded, Avista Utilities' prediction of 1.85% conservation versus before the demonstration.

Reactive power management was observably effective. Power factors were observed to improve markedly after 2012, but degraded again in 2014 as the VAr management was being actively tested. The project looked for evidence of additional improvements that would accompany activation of the automated IVVC system. Reactive power management contributed to the estimated conservation impact that was stated for voltage management, but a change in power from reactive power management cannot be independently determined apart from the impacts of voltage management. The times that power factor correction was employed were found to be correlated with times of voltage management, but the correlation was imperfect. Four of the 13 feeders were likely to have further reduced distribution line losses by more than 1% with the application of VAr management. The greatest impact was a reduction of line losses of around 4.6%.

Avista Utilities supplied the project a count of capacitor switching operations for each of its South Pullman feeders. Capacitor switch actuations increased significantly for several of the feeders in spring 2013, about the time that voltage and VAr management became active.

At the conclusion of the PNWSGD project, Avista Utilities stated that one-third of the Pullman, Washington, site customers were under IVVC. Based on its preliminary findings, Avista Utilities plans to enhance all 13 Pullman, Washington, feeders with IVVC. The utility estimates that optimization of distribution voltage alone will save the utility $0.5 million dollars annually, based solely on the value of the energy that will be conserved.

7.2 Reconductoring

This test case will involve reconductoring of approximately one mile of key feeder segments using 795 all aluminum conductor to reduce system losses and provide operational flexibility. Alternative circuit configurations were limited prior to this improvement in power capacity on these feeder segments. The project's understanding is that two feeders—Pullman 112 and South Pullman 123—were improved by this upgrade.

Table 7.6 lists the annualized costs of the system and its components. The greatest cost was for upgrades to the DMS, followed by line switches and fiber network communications upgrades. The total annualized system cost was about $0.6 million.

Table 7.6. Components and Annualized Component Costs of the Avista Utilities Reconductoring Effort

System Component	Component Allocation (%)	Allocated Annual Component Cost ($K)
DMS Software and Hardware for 700–1,000 End Points	25	420.8
Automated Line Switches	50	72.6
Fiber Network Communications	17	53.4
Evaluation, Measurement & Validation	13	22.8
Project Management Services	13	12.9
Subcontractor – Volt/VAr Software	33	12.7
Reconductoring	33	11.8
Total Annualized System Cost		**$607.1K**

7.2.1 Data Concerning the Reconductoring

The reconductoring was reported by the utility to have been completed by the end of October 2010. The PNWSGD received no measurements from Avista Utilities from which the impacts of the reconductoring could be directly estimated. Instead, the utility submitted and the project must rely on estimates of these savings that were calculated by Avista Utilities' distribution engineers and planners, based on data from the DMS and SynerGEE, an engineering software tool, each month. The line losses are apparently estimated from each month's line currents and the difference in resistivity between the new and replaced conductors. The received data is shown in Figure 7.22. Avista Utilities reports that the missing data months are artifacts of its rebuild of its Pullman substation, which became the Turner substation during the project. During this construction, feeders were supplied from alternative substations, creating the data artifacts. No calculated data is missing.

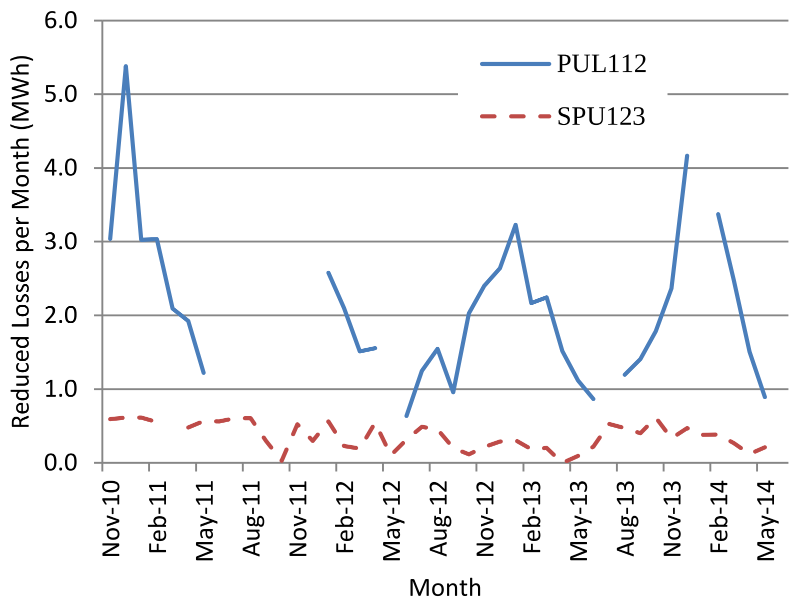


Figure 7.22. Calculated Reduction in Distribution Energy Losses on Two Pullman, Washington, Distribution Feeders each Month

7.2.2 Analysis of the Impact from Reconductoring

Based on the calculations made by Avista Utilities and shown in Figure 7.22, the utility will conserve 29.6 ± 0.6 MWh each year by having upgraded the conductors on the two feeders. Most of this conservation, 25.2 ± 0.3 MWh per year (average 2.1 ± 0.2 MWh per month) occurred on Pullman Feeder 112, while 4.4 ± 0.1 MWh per year (average 0.36 ± 0.03 MWh per month) is saved on South Pullman Feeder 123. These estimates were based on reported data, excluding any impacts from months on which no conservation savings had been reported by the utility.

The value of the conserved energy is less than $3,000 per year. However, the capability of new distribution automation features in Pullman, Washington, might have been constrained had these upgrades not been completed.

7.3 Smart, Efficient Transformers

Avista Utilities replaced ~383 of Pullman's 1200 distribution transformers with smart transformers that are equipped with advanced sensors and telemetry for the remote measurements of voltage, current, and transformer temperature. The utility piggy-backed onto existing collaborative research between Howard Industries (Howard Industries 2015) and Southern California Edison to develop and test improved distribution transformers. The transformers to be replaced were those that had been installed before 1983. An economic analysis determined that distribution transformers installed before 1983 did not meet the utility's present efficiency standards and should be replaced. The purpose of this report section is simply for the project to confirm the improved efficiency performance of the new transformers.

The high efficiency design and construction of these smart transformers was anticipated to provide a constant reduction in both load and no-load losses. Additionally, the electrical metering of the smart transformers was available for use in conjunction with the utility's integrated volt/VAr management system (Section 7.1), and the power passing through the distribution transformers may be compared against measurements of aggregated power from the AMI at customers' premises to detect electricity theft. The temperature of the new transformers may be monitored to detect imminent failures and thereby avoid customer power outages (Section 7.7).

The estimated annualized costs of the system of smart transformers and its components are listed in Table 7.7. The efficiency impact of these new transformers was assigned a small fraction of the annualized costs of many of the components that were shared among the assets. Among the greatest component costs were those of the improved demand-management system, communication upgrades, and the transformers themselves.

Table 7.7. Components and Annualized Component Costs of the Avista Utilities System of Smart Transformers

System Component	Component Allocation (%)	Allocated Annual Component Cost ($K)
Demand Management System Software and Hardware for 700–1,000 End Points	25	420.8
Fiber Network Communications	17	53.4
Smart Transformers Equipped with Sensors, Current Transformers, and Wireless Communications	25	37.3
Evaluation, Measurement and Validation	13	22.8
Project Management Services	13	12.9
Subcontractor – Integrated Volt/VAr Software	33	12.7
Total Annualized System Cost		**$560.0K**

According to the utility's calculations prior to the PNWSGD project, the anticipated energy savings from transformer upgrades in Pullman was an average 130 kW, or 1,120 MWh annually, equating to the energy use of about 50 homes and a value of over $111 thousand. If correct, these loss reductions are on the order of 1.4–4.5% of the average customer load. The project was unable to confirm these savings. The utility did not provide metadata to identify which customers' transformers had been replaced, and the replacements were not consolidated on a single or a limited number of distribution circuits where the impacts might have been estimated by comparing historical and recent circuit loads. The utility responds that the transformers' no-load losses were validated at the factory

In short, the project was unable to confirm the energy efficiency performance of the Howard Industries smart transformers that Avista Utilities installed at the Pullman, Washington, site.

7.4 Residential Thermostats

Avista Utilities provided a group of test residences with Ecobee smart thermostats (Ecobee 2015) to launch a residential load response program in Pullman, Washington. Avista planned to place an emphasis on customer education, customer participation and energy management. Customers who volunteered to participate in the larger project and allow control of their thermostats would create a virtual power plant when the regional value signal warranted a response.

The utility originally targeted obtaining 1,500 program participants. The Avista Utilities Smart Thermostat Pilot (STP) was a voluntary program offered to a select group of customers in Pullman and Albion, Washington. Eligibility requirements were narrow, with the intent of selecting those consumers who were likely to maintain their current living arrangements throughout the study period (2012–2014). Selection criteria for programmable communicating thermostat (PCT) candidates were that the applicant must be an Avista Utilities customer; not be a student; own and occupy a single-family residence; be able to place the thermostat near the AMI (and near the gas meter, too, for gas customers); use electric forced air heating, heat-pump, or central air conditioning; possesses a secure wireless router; and make a six-month minimum commitment to remain in the program. These eligibility criteria reduced the available candidates to 650 homes.

After considerable review of market-available smart thermostats and their communications, Avista Utilities chose Ecobee's Smart Thermostat as the target PCT for deployment. The Smart Thermostat has a dual-radio capability permitting communications with either whole-house consumption meters via ZigBee (IEEE 802.15.4) or with authorized Wi-Fi networks (IEEE 802.11). The ZigBee interface, as well as serving a role during the "pairing" process between the PCT and the AMI meter, is also the communications pathway to display quasi real-time electric consumption information to the consumer. The consumer's Wi-Fi/internet interface is the direct communications path between the PCT and the PCT vendor, Ecobee.

When the PCT is paired with the AMI meter, the display of the Smart Thermostat's consumer interface graphically showed a number of useful energy consumption parameters, including real-time energy consumption, the premises' electricity usage over the last hour, total electricity used so far that day, and hourly, daily, weekly, and projected cost reports.

With Wi-Fi, customers can view weather forecasts and other useful information from the same device. The integrated display of the PCT addressed Avista's concern that a separate in-home display would not be cost-effective over the entire program period, while an integrated display in the PCT would provide value on an ongoing basis. Customers may access their thermostats using their smart tablet or smart telephone independent of the utility. This smart-device connectivity is directly to Ecobee and will continue without cost to the customer after the STP program has ended. Smart-device access to the Ecobee thermostat also allows the user to remotely adjust their thermostat settings and/or view the operation of their furnace. Additional online information through the Ecobee portal includes the following: monetary value of historical electric usage; ability to set a budget amount and be alerted when usage meets or exceeds the set amount; HVAC operational information; ability to set furnace maintenance alerts, such as filter replacements, annual maintenance, etc.; ability to export usage history; and consumer insights on HVAC operation related to weather and month-over-month data.

The utility had also intended to control electric water heaters, but that part of the system was not successfully developed. Gas water heaters are more prevalent in the Avista Utilities service territory than electric ones.

The utility offered to make the system of smart thermostats responsive to the PNWSGD project's transactive system that advised systems like these when to curtail load.

Avista Utilities conducted a survey to assess various recruitment practices for residential-load customer participation, and a survey concerning customer acceptance of the load-control devices and the incentives provided. Surveys, customer focus groups, demographic studies and profiles for controllable devices at each premises were leveraged to further shape concepts and staging of this two-pronged residential load control program. Avista will maintain a sharp focus to achieve success and customer satisfaction.

Residential demand-response (DR) programs historically have had a high level of interaction between the utility and the customer, primarily due to the DR event notification process. However, the STP events were automated, which allowed the program to function more like an energy efficiency program with limited interaction between the customer and the utility. This resulted in improved customer satisfaction by demonstration of the closeout survey.

To entice participants, a number of incentives were offered to potential participants: an HVAC system inspection was provided at no cost, the PCT was provided and installed at no cost, and a $100 per year "appreciation payment" was given participants during the project term. Although various communication channels were used to engage customers—including a concentrated direct marketing push over the summer of 2012—by the end of September 2012, only 36 thermostats had been installed, and no overwhelming interest by customers was being observed. The lessons learned were

- Strict participation criteria had narrowed the pool of potential participants.
- The utility possessed limited tracking tools and no customer-relationship–management database.
- Once the program was explained, people were receptive.
- Personal contact was the most effective method in securing participation.

In mid-October 2012, Avista Utilities decided to suspend active recruitment of Pullman customers for the STP and use the number of current enrolled participants to evaluate the program's value against the objectives of the STP. The program team executed the no-cost outreach efforts and speaking engagements that were already in the works. One such activity that proved successful was an email posting at SEL in early October that resulted in 11 Schweitzer employees signing up to participate. This is an example of engaging the right target audience. By the September 2013 enrollment deadline, recruitment efforts achieved 75 participants in the STP.

Avista Utilities had to coordinate the efforts of multiple vendors to integrate the system of smart thermostats. Close working partnerships with vendors led to much greater likelihood that products would meet the utility's needs. The system integration challenge is portrayed by Figure 7.23. Players in the integration included

- Ackerman Heating and Air Conditioning, who conducted all field work for thermostat installation and maintenance and managed thermostat inventory
- Ecobee, who provided and integrated thermostats and hosted central connections to the thermostats
- Integral Analytics, who conducted predictive analytics for the command and control of the thermostats during DR events and worked with Avista (via Spirae, Inc.) and Ecobee to integrate these commands
- Spirae, who completed an interface with the PNWSGD project to process transactive control signals.

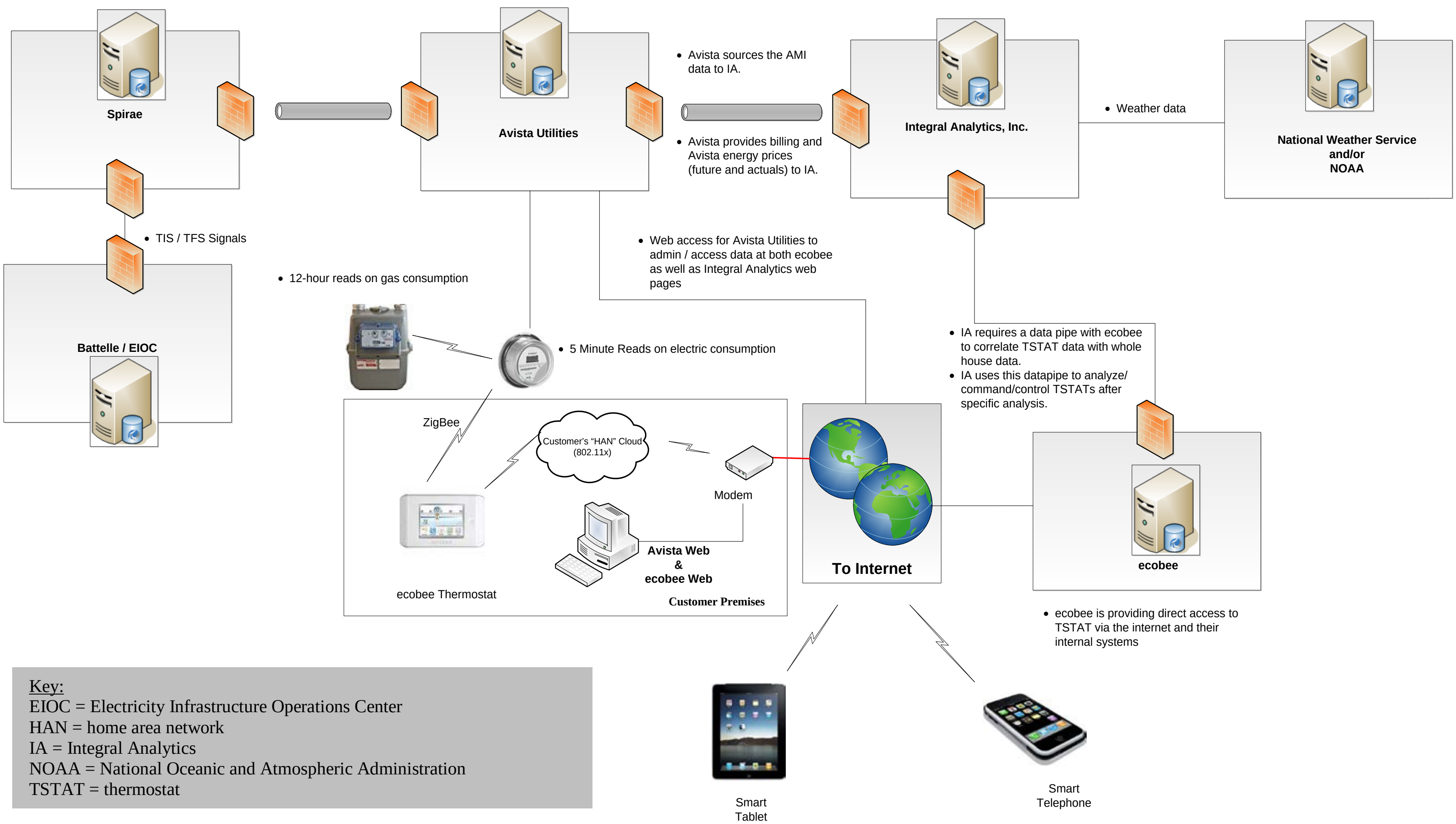


Figure 7.23. Subsystems that had to be Integrated to Complete Avista Utilities' Smart Thermostat System

Avista Utilities addressed physical security through the use of an internal security audit of its vendors and established a direct virtual private network with them. The audit determined that a combination of authentication requirements and Secure Sockets Layer certificates ensured that unauthorized entry into its infrastructure was extremely low. Avista Utilities allowed no customer-identifiable information to be part of the data exchange process.

The annualized costs of the smart thermostat system and its components are listed in Table 7.8. The most costly components were the allocated fraction of AMI costs, the cost of implementing the DR control system, the thermostats, and customer portal software.

Table 7.8. Components and Annualized Component Costs of the Avista Utilities Communicating Thermostat System

System Component	Component Allocation (%)	Allocated Annual Component Cost ($K)	
Advanced Metering System		433.6	
• Software and Systems	25		316.0
• Operations and Maintenance	25		100.3
• Engineering	25		7.7
• Residential Equipment - Target Group with DR	25		7.1
• Training	25		1.9
• Commercial Equipment - Target Group	25		0.7
Demand-Response Control System	100	413.1	
Demand Response - Thermostats	100	342.2	
Customer Portal - Software		195.3	
• Engineering	50		77.7
• Hosted Software Costs (Target Group with DR)	50		60.0
• Software and Systems Installed Costs	50		37.6
• Operations and Maintenance	50		20.0
Evaluation, Measurement and Validation	13	22.8	
Customer Service	25	10.5	
Outreach and Education	25	7.9	
Total Annualized System Cost		**$1,816.8K**	

7.4.1 Data concerning the Residential Thermostats

Project analysts attempted to verify the impact of residential load control in Pullman using aggregated residential metering. Metered power data was averaged from 57 premises that had received controllable load-control devices like thermostats. This number differs from the 75 premises that Avista Utilities reported they had recruited. The difference might be attributable to miscommunication concerning the feeders on which these tests were conducted and not. Project analysts had been led to believe the test premises would be on the seven non-WSU feeders only, which might not have been the case. The project also identified a larger set of 9,037 premises that never received residential load control devices and might serve as a comparison baseline.

Upon comparing the raw power data from the test and baseline groups, the project observed what might be a significant selection bias. The test group premises might be larger than average and seem to consume somewhat more energy than the baseline group. The difference is most evident in warm summer months, as is shown in Figure 7.24, when the test members consume three times more electricity than the baseline members. Perhaps the test group members have air conditioning that is not common among the rest of the population in Pullman. Interestingly, the two lobes of the fall season comparison were evident in two of the three years in which data was collected. For these reasons, the comparison group could not be used.

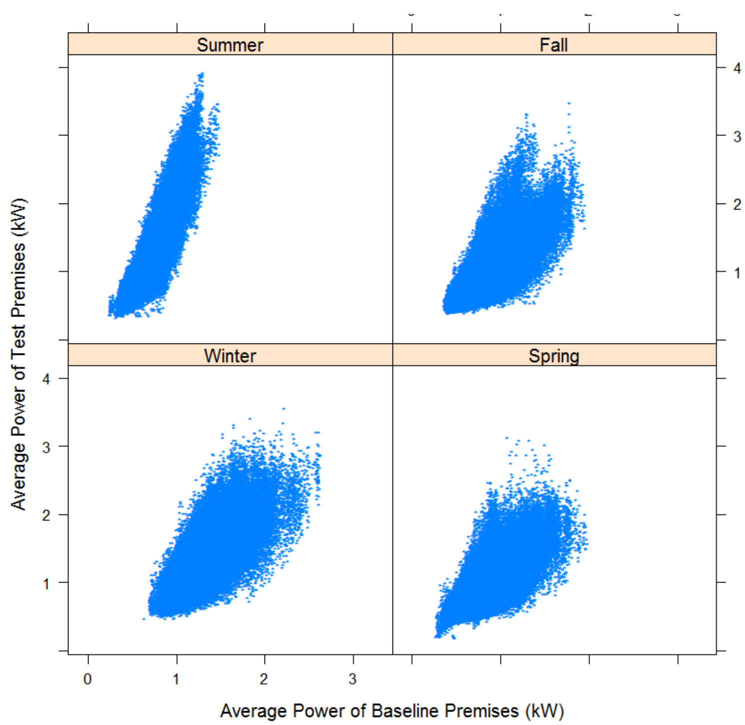


Figure 7.24. Comparison of the Average Power of Premises that Received Residential Load Control Devices and Others that Did Not, by Season

The averaged premises power data from the test premises that received residential DR equipment is shown in Figure 7.25. The legend refers to the marking of this power data according to whether the transactive system was actively advising that the system curtail load (active) or not (normal). The premises do not exhibit much weekly variation, and they exhibit relatively small variation by season. Data was available from January 2011, but the transactive signal was not defined until 2013. Data was intermittently available in 2013. Data collection continued through August 2014.

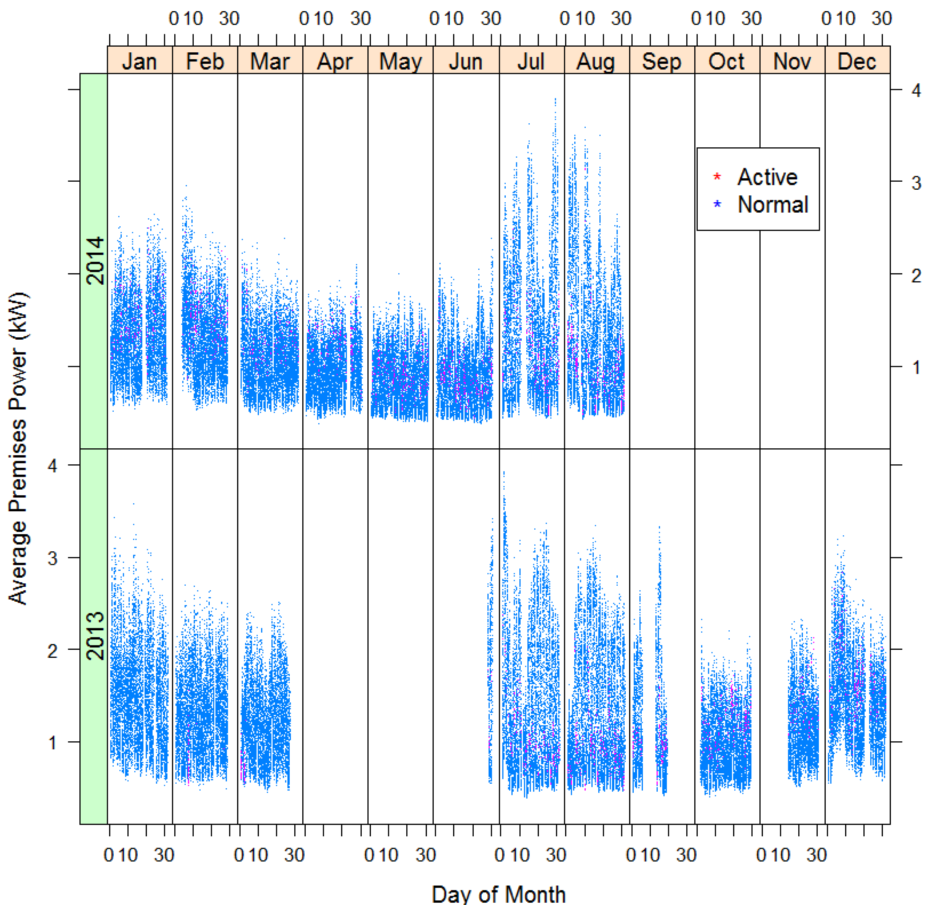


Figure 7.25. Average Residential Premises Power Data Collected from Avista Utilities Concerning Customers that had Received STP Thermostats

Avista Utilities' STP participants received a total of 636 DR event requests over the course of two years. Events averaged two hours in duration and consisted of a two-degree temperature increase or decrease, depending on the season. The PNWSGD project's transactive system initiated 405 events. The Avista-generated signal (AGS) DR events were called 231 times. A breakout by year is shown below in Table 7.9.

Table 7.9. Counts of Thermostat DR Events that were Initiated by Avista Utilities (AGS) and the Transactive System (TIS), as Reported by Avista Utilities

Year	AGS	TIS	Grand Total
2013	104	54	158
2014	127	351	478
Grand Total	**231**	**405**	**636**

AGS = Avista generated signal
TIS = Transactive incentive signal

Figure 7.26 breaks down the utility's event counts further by both year and month.

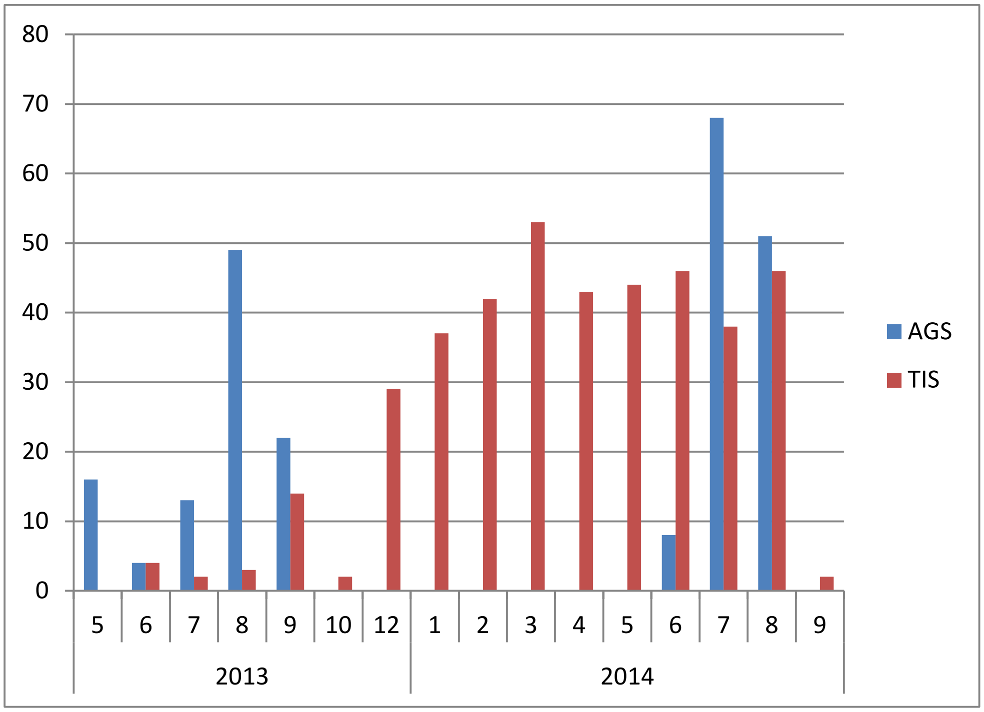


Figure 7.26. Utility (AGS) and Transactive System (TIS) Events by Year and Calendar Month

The project received complete information through the project's transactive data collection system concerning the times and durations of all the events that had been advised by the project's transactive system. However, the project did not receive any information concerning the times and durations of the Avista-generated DR events. The following discussion will characterize the times that the transactive events were advised. Analysis will attempt to confirm an impact from these events on residential power consumption. These steps were not possible for the Avista-generated events. Furthermore, the Avista-generated events may have affected the presumed baseline data periods, when the project believed no demand responses were taking place.

The transactive system advised that the system respond about 97 hours in 2013 and 124 hours in 2014. The distributions of those 5-minute intervals by calendar month are shown in Figure 7.27.

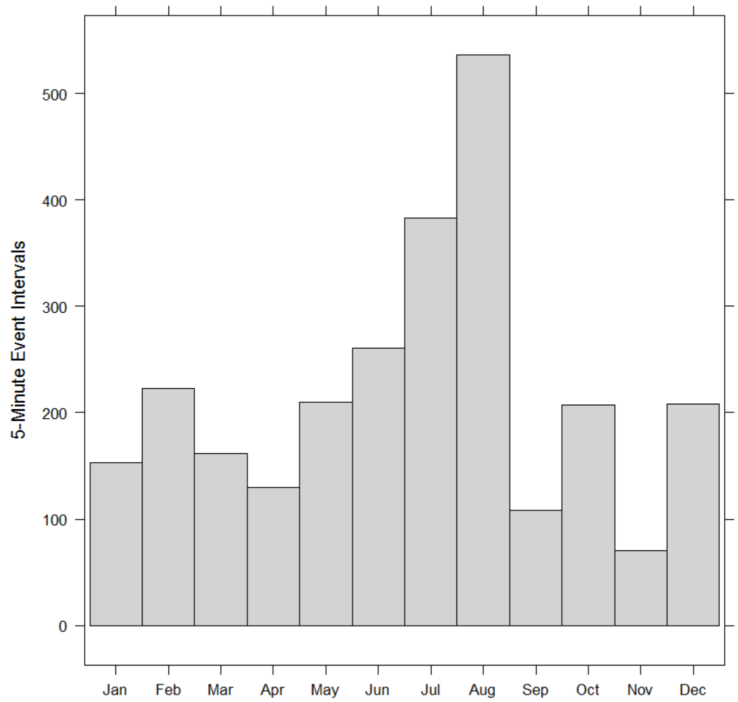


Figure 7.27. Counts of Advised Transactive System Event Intervals by the Months that those Intervals Occurred

The transactive system advised its events evenly across the days of week, as is shown by Figure 7.28. Avista Utilities had encouraged configuring the function by which these events were advised according to the utility's preferences.

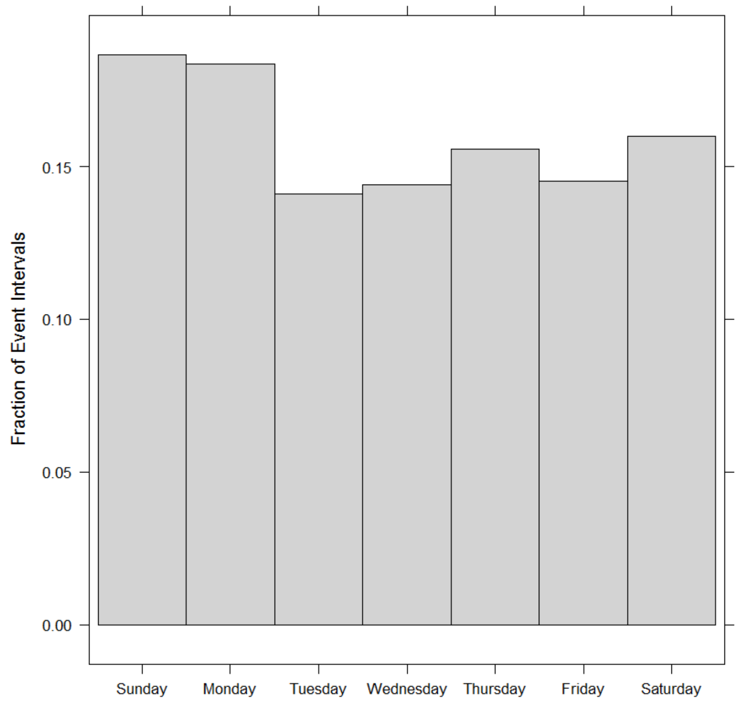


Figure 7.28. Relative Distribution of Advised Transactive System Event Intervals by the Days of Week that those Intervals Occurred

Most of the event periods were advised during between 08:00 and 10:00, as is shown in Figure 7.28.

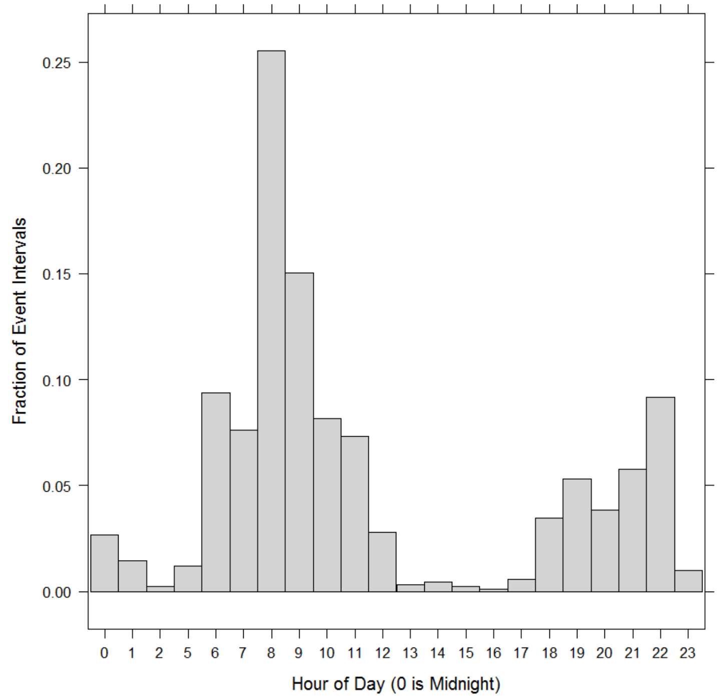


Figure 7.29. Relative Distribution of Advised Transactive System Event Intervals by the Hours of Day that those Intervals Occurred

7.4.2 Analysis concerning the Residential Thermostats

Regression analysis was conducted using the average power of the test premises that had been given the smart thermostats. The power data was modeled as a function of season, hour of day, and transactive event status in permutations with ambient temperature. The regression model was used to create a prediction of what the averaged power would likely have been had the transactive system not advised curtailment. The differences between the original averaged premises powers and the regression model (which emulated having no events) were compared both during event and non-event periods. A Student's t-test was used for this comparison, treating the event periods and non-event periods as independent populations.

Overall, there appeared to be a small reduction on the order of 18 W during events. However, the project's confidence in this result is low. There is approximately an 87% chance that any reduction occurred at all. The results from only two seasons were statistically significant. In summer, there was a reduction of 40 W, but in fall, there was an increase of 73 W. Recall that premises power data had been rather incomplete in fall 2013.

The project cautiously confirms that homes with smart thermostats reduced their energy consumption during advised transactive events, but the impact was small. The analysis lacked confirmations of which events had, in fact, been called. The analysis was confounded by lack of information about the timing and occurrences of DR events that were independently initiated by the utility for these thermostats; those events may also have polluted the baseline.

Avista Utilities gathered much information about how its customers had used the smart thermostats, how the program affected their energy consumption habits, and opinions about their electricity service.

From 31% to 71% of thermostat recipients were found to use the Ecobee mobile application on a weekly basis. However 29% of the thermostat recipients had never used the mobile application during the course of the Smart Thermostat Program. Of those who had used the mobile application, over 70% rated the application as “very useful.”

Avista Utilities surveyed its thermostat program participants to understand customer acceptance of the ecobee thermostats and the DR events. During the course of the PNWSGD, Avista Utilities received three requests from customers to remove the ecobee thermostat from their homes. Two had found the thermostat were too difficult to use (touch screen and drill-down menu options), and one customer felt the thermostat negatively affected his HVAC system. No evidence was found to support this latter claim. About 43% of respondents said they had been able to detect the set-point changes being made to their thermostats, but about 55% said they rarely or never noticed these changes (Table 7.10). Of the thermostat recipients, 88.64% said they had been very satisfied with the utility’s Smart Thermostat Program.

Table 7.10. Survey Responses to the Question, “During the STP Program were you able to detect when Avista made set point changes?”

Answer Choices	Responses	Response (%)
All the time	3	6.82
Sometimes	16	36.36
Rarely	9	20.45
Not sure	1	2.27
Never	15	34.09

Low opt-out levels imply that there was no noticeable change in customers’ comfort. Customers always had the choice to opt out of approaching DR events if they wanted or needed to do so. That choice perhaps helped drive high satisfaction levels.

The program’s customer incentives had been designed generously to gain the highest level of program participation in the least amount of time. The survey results indicate that these incentives were needed for about half of the customers for participation.

Table 7.11. Survey Responses to the Question, "If Avista had not provided the product, installation, and incentives for the ecobee thermostat, how likely would you be to install the ecobee thermostat on your own?"

Answer Choices	Responses	Response (%)
Extremely likely	4	9.9
Somewhat likely	12	27.27
Neutral	9	20.45
Somewhat unlikely	17	38.64
Not at all	2	4.55

7.5 Advanced Metering Infrastructure, Web Portals

Avista Utilities used the PNWSGD to replace all of its manually read utility meters—about 14,000 electric meters and 6,000 gas meters—with AMI. They selected Itron Open Way advanced meters (Itron 2015). The utility also installed a 900 MHz radio frequency mesh network throughout Pullman, Washington, to communicate with the new meters. In this section, the project reviews energy and operational efficiencies that directly or indirectly accompany advanced metering. For example, Avista no longer must send personnel to read customer meters, and fewer truck rolls may needed to read or check up on the newer meters.

Itron's Open Way AMI replaced all meters for the customers served by the Pullman, South Pullman, and Terre View substations. These meters use a 900 MHz multichannel mesh radio network, allowing every meter to act as a router to get information to a gateway device at 45 of the 802.11-type access points. It should be noted, Itron has very advanced security designed into this system. Meters are manufactured with an embedded key that is generated by Avista's security key device. The keys cannot be duplicated and can only be backed up on redundant hardware at Avista. Any device attempting to control a meter must supply the hardware-generated key.

The meters store usage data at 5-minute intervals for up to 90 days. Voltage measurements are available and may be used during the optimization of distribution voltages. A ZigBee gateway is included for communication with home area networks, which allows customers to obtain usage information directly from the meter. The meters are read remotely using software from Itron, the Open Way Collection System, that provides meter data management and meter communication.

All new meters were read remotely, eliminating two meter reader positions. It should be noted that although two meter reading positions were eliminated, new back-end system support was needed. The three support positions were required regardless of the scale of deployment, meaning that when AMI becomes deployed for all Avista customers in the state of Washington, few additional staff should be required. With the remote metering capability, high-bill complaints and other billing questions can be answered without requiring visits from service personnel. Customer calls initiated for power outage reasons can be validated remotely, eliminating the dispatch of service personnel and allowing the call representative to walk the customer through the process of checking their in-home breakers or fuses for quickest return to service for the customer. The average number of calls that fall into this category annually is 50.

Because Avista Utilities may remotely query the advanced meters, more accurate determination of fault locations and power status are possible. This superior information may reduce travel and trouble-assessment time for crew resources. Another benefit for AMI is the ability to validate that restoration efforts were successful by remotely checking status after repairs are made. This makes sure that customers with unresolved service problems are not overlooked.

By reducing the need for visits to customer locations, employee safety may have improved. The service personnel were less likely to encounter dangerous dog and hostile customer situations.

Smart transformers and AMI provided for detailed load and loss evaluation. Transformer usage that does not match the corresponding customer load usage indicates unidentified losses and theft. Studies suggest that for the United States as a whole electricity theft could be as high as 2–5% (source Itron). Avista estimated that 0.07% of total load for the included meter installs—220 MWh per year, the energy usage of 10 homes—may be saved.

The new meters include a service switch that allows connect/disconnect operations to take place remotely without dispatching service personnel. Given the student population in Pullman, utility accounts are opened and closed frequently. Meters can be connected, disconnected, or read remotely, freeing service personnel for other work and improving billing accuracy.

Partner Hewlett-Packard Company (HP®) provided computer hardware, services and monitoring software to support the Itron solution.

Perhaps most importantly, smart meters allow customers to participate in and learn about their energy consumption. Five-minute electric usage and one-hour gas usage intervals can be displayed over the web. Customers may compare themselves against other customers, groups, or regions of the country. Customer renewable generation, if installed, can be profiled along with energy usage. The web portal provides a wealth of information to educate customers and create interest in energy management. Most of the project’s effort in this section was spent trying to validate whether this reduction in load had, in fact, accompanied the education of customers made available to them via their web portals.

The annualized costs of the entire system and its components are estimated in Table 7.12. The costs include a fraction of costs of the AMI system, a fraction of the costs of upgrading the fiber optic communications system, a fraction of the costs of evaluation, measurement and validation, and other smaller cost components. The total annualized cost was estimated at about $1.2 million per year.

Table 7.12. Components and Annualized Component Costs of the Avista Utilities System of Advanced Premises Metering Displays

System Component	Component Allocation (%)	Allocated Annual Component Cost ($K)
AMI		511.9
• Software and Systems	25	316.0
• Operations and Maintenance	25	100.3
• Residential Equipment - Control Group	33	39.2
• Engineering	25	7.7
• Training	25	1.9
• Commercial Equipment - Target Group	25	0.7
Customer Portal - Software		435.3
• Hosted Software Costs - Control Group	100	120.0
• Hosted Software Costs - Target Group	100	120.0
• Engineering	50	77.7
• Hosted Software Costs - Target Group with DR	50	60.0
• Software and Systems Installed Costs	50	37.6
• Operations and Maintenance	50	20.0
Fiber Network Communications	17	53.4
Project Management Services	13	12.9
Evaluation, Measurement and Validation	13	22.8
Customer Service	25	10.5
Outreach and Education	25	7.9
Total Annualized System Cost		**$1,228.0K**

7.5.1 Data Concerning AMI and Web Portal Efficiencies

Avista Utilities defined test and baseline groups to review the impacts of web portals on customers' energy consumption in Pullman, Washington. The random selection of these customers and other details about the comparison were detailed in a Freeman, Sullivan and Company report[1] that analyzed the impact of web portals for Avista Utilities. The project did not necessarily receive the same data and information about the conduct of the experiment as was used in that report. Several possible discrepancies will be pointed out.

The project received 5-minute power data for these premises, which the project aggregated into two time series of averaged premises power. The counts of participating residents rose steadily between February and April 2011, which probably points to a period that AMI metering was completed in

[1] Sullivan MJ, CA Churchwell, MM Blundell, and CV Hartmann. 2013. "Avista Smart Grid Demonstration Project Study and Analysis of Customer Energy Usage." Report prepared for M Dillon, Avista, by Freeman, Sullivan & Co., 101 Montgomery St., 15th Floor, San Francisco, CA 94104, October 22, 2013.

Pullman. The project did not receive historical monthly data from these premises. Eventually, the premises counts rose to about 4,306 test premises and 4,276 baseline premises. Industrial and commercial premises were not included, leaving only residential premises. The project discarded data intervals if fewer than 95% of either the test or baseline premises were reporting their data. This practice removed much partial data from before May 2011 and also removed periodic intervals when there might have been data communication problems.

The project's understanding was that the test premises were provided access to Avista Utilities' web portal. Some in this group may have viewed hourly consumption, too, from their smart thermostats. The baseline premises were unable to access and view their hourly energy consumption from a web portal or from any other device. The project's understanding was augmented by the Freeman, Sullivan and Co. report, which said this was not necessarily the case. According to that report, the test population (their "treatment" group) was granted access to web portals in April 2012, but all customers, including the baseline (their "control" group) were granted access to energy Web portals in April 2013, after the study ended. These distinctions were not evident from the utility or from the supplied data.

The two aggregated and cleaned data sets are shown in Figure 7.30. Even from this raw time-series data, the baseline ("control") group's energy consumption appears to be greater than that of the test ("experimental") group. The average of the project's baseline group time series was 970.1 ± 0.6 W, and that of the test group was 916.3 ± 0.6 W. The difference between the two populations is unusual for randomly selected memberships. This difference was also recognized in the Freeman, Sullivan and Co. report (p. 9), but that report said that energy consumption of the control group was around 8–10 kWh per month *less* than that of their treatment group.[1] This contradiction calls into question the quality of the data collection process and both the project's and the cited report's analysis and conclusions.

[1] The comparison will be completed and the contradiction confirmed later in this section when the project's assessments of monthly energy will show the same bias as was suggested from the power plots.

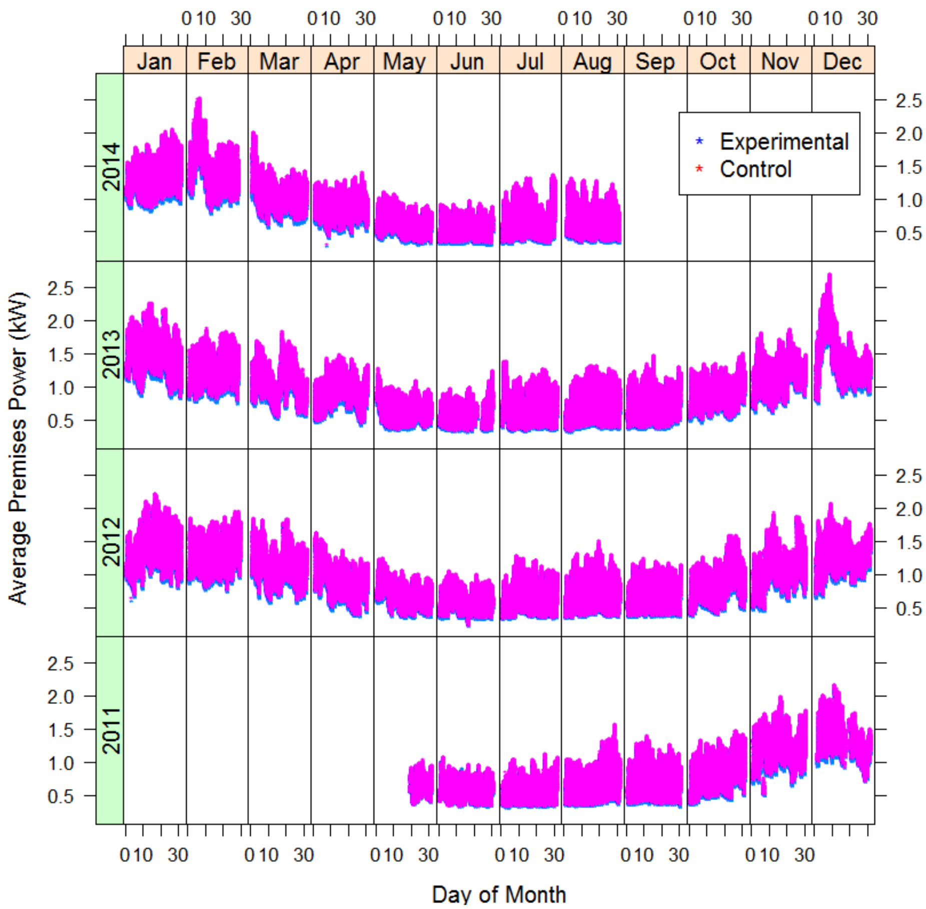


Figure 7.30. Average Premises Power Data from Test and Baseline Residence Groups

A time series of ambient temperatures from weather station KPUW was available to the project and is shown in Figure 7.31. This weather station is located at the Pullman-Moscow Regional Airport. The temperature data was found to be fairly complete, but several lone outliers were identified at and near 0°F. To improve the completeness of the data, temperatures between −1.4 and 1.4°F) were deleted. Then, the missing data, including where the near-zero values had been removed, were interpolated. Interpolation was allowed where data was found to be missing for less than 6 hours. This method recovers most of the values that were legitimately close to 0°F, as these cold temperatures sometimes occur at this site.

The information from web portals might have a small impact on the voluntary energy behaviors of residents. The project will apply temperature corrections as it strives to identify this impact. Therefore, the quality of ambient temperature data is critical to this analysis.

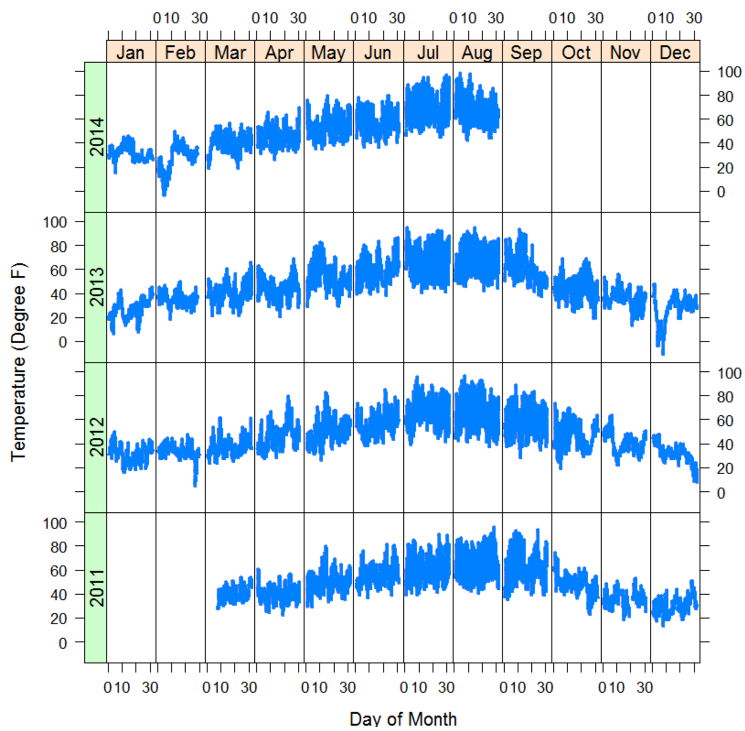


Figure 7.31. Ambient Temperature Data from Station KPUW (Pullman-Moscow Regional Airport)

Figure 7.32 previews the relationship between power consumption of the test and baseline groups as a function of ambient temperatures. A relationship is demonstrated and the familiar “V” shape is observed. Minimum consumption occurs when the ambient temperature is in the spring and fall comfort ranges. At extreme cold (left side) and hot (right) temperatures, the premises consume more energy. This figure again shows that the control residences consume more than the test ones at the same temperatures. This relationship between power consumption and temperature will be critical for analysis.

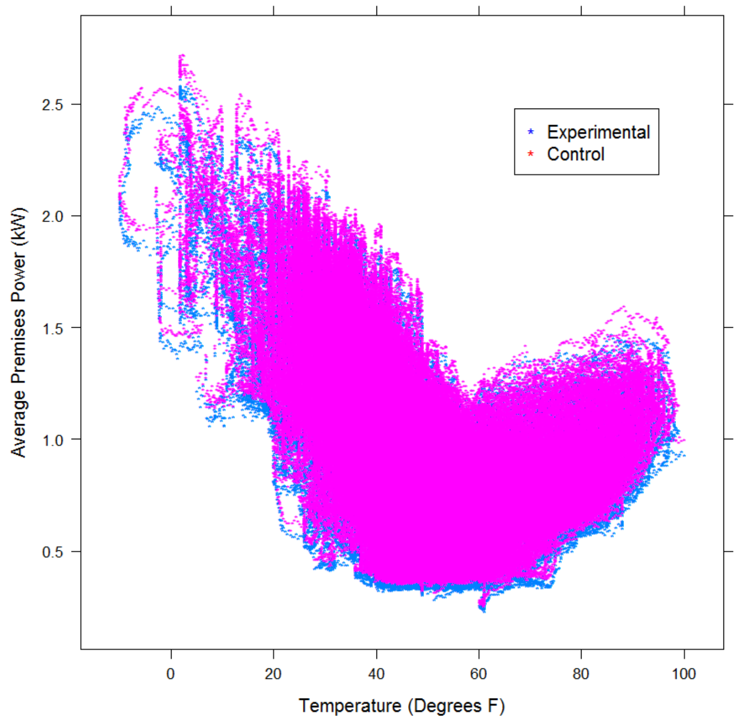


Figure 7.32. Average Premises Powers of the Test ("Experimental") and Baseline ("Control") Groups as Functions of Ambient Temperature

Avista Utilities compiled and submitted several metrics concerning the performance of its new AMI system at Pullman, Washington. Figure 7.33 presents the percentage of AMI meter reads that were successfully completed by 02:00 the next day. Using available data, these reported daily percentages were placed in increasing order and were plotted against the percent of all the available measurements. Based on available data, 100% of the meters were successfully read by 02:00 only 1.2% of the time. However, this figure shows that 98% or more of meters are successfully read 95% of the days.

The above paragraph was qualified several times by saying that it refers only to those intervals for which data was available. In fact, reported data for this metric was quite incomplete. The project looked at the days that AMI meter data had been reported and compared those counts to the days that this metric was calculated and reported. The metric was reported only 33% of the days that AMI meters were actively reporting premises energy consumption.

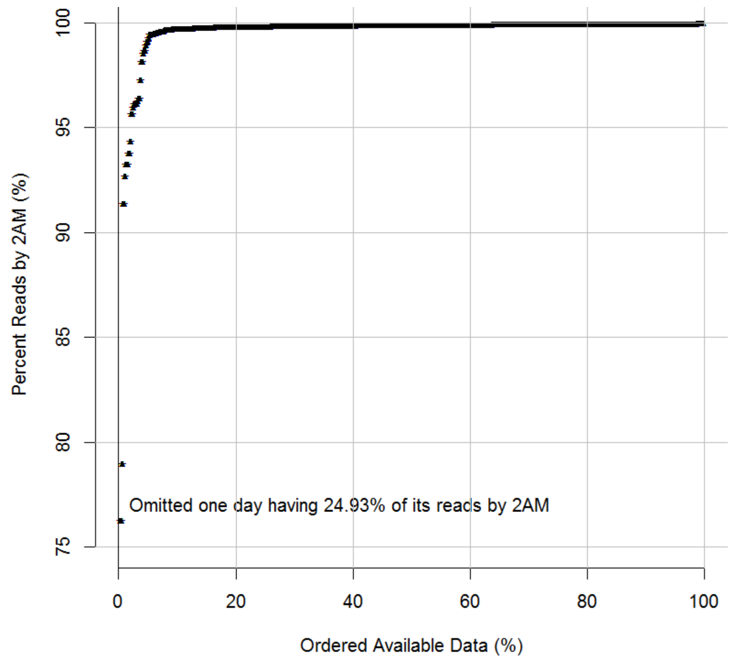


Figure 7.33. Distribution of the Available Data for the Percent of AMI Meter Reads Completed by 2 AM

Avista Utilities also estimated the numbers of truck rolls that had been avoided by its AMI meter operations department. These counts are listed my month and year in Table 7.13. The project understands these avoided truck rolls to have been automatically calculated based on types of service calls received that would have previously required a service visit that was made unnecessary by the features of the new AMI. For example, truck rolls are now unnecessary to shut off and restart electric service as college students leave and return to rental properties. And when a customer calls, the utility can remotely determine whether their meter is electrically "live" or not.

Avista Utilities also reported the avoided number of driven miles for meter operations. It turned out that this was not a unique calculation. Each avoided truck roll had been presumed to avoid exactly 15 driving miles for meter operations.

The utility's internal business case includes not only the direct costs of staff and vehicle maintenance, but also includes the unlikely but potential costly impacts should the vehicle have an accident while it is being used.

Table 7.13. Count of Avoided Truck Rolls Reported by Avista Utilities for Project Months

	2011	2012	2013	2014
Jan	-	311	205	252
Feb	-	239	261	245
Mar	0	276	288	182
Apr	0	224	281	201
May	0	270	357	222
Jun	0	217	230	0
Jul	3	263	276	0
Aug	0	219	251	0
Sep	0	146	151	-
Oct	1	160	214	-
Nov	141	177	200	-
Dec	162	199	195	-

7.5.2 Analysis of AMI and Portal Efficiencies

The project attempted to observe a change in premises energy consumption attributable to customers' access to energy web portal information, but the project did not duplicate all the facets of the web portal program that were well addressed in the Freeman, Sullivan and Co. report. In addition to energy impacts, that report reviewed how, when, and whether customers used the web portal; impacts of the web portal on gas consumption; qualitative feedback from focus group members, and customer survey findings. Among the report's highlights, 68% of survey respondents said they visited the Avista website monthly (Freeman, Sullivan and Co. report, p. 3). Only 5% of the treatment group ever accessed the pertinent website content (Freeman, Sullivan and Co. report, p. 14).

The project accepted the statement in the Freeman, Sullivan and Co. report that the test group was first given access to web portal information in April 2012. If any change occurs in the behavior of the test group, its energy consumption should change after that month. The baseline group should not have received access to web portal information, so its behaviors should not change after that month. The difference in any observed changes after April 2012 between the two groups might be attributable to the availability of web portal information.

The project carefully summed the average monthly energy consumption by each group. A simple sum might underreport the energy consumption in a month that data was incomplete. Therefore, the project first calculated each month's average power, then average powers were multiplied by the precise number of hours each month to estimate total energy consumption per premises in that month.

The month's average premises energy consumptions have been plotted against time in Figure 7.34. More than three years' data are included. The dashed vertical line marks the project's new understanding of when the treatment—access to a web portal—began for the test group. The project wished to analyze full years both before and after the treatment, lest the analysis be corrupted by seasonal variations. April 2012 was considered pretreatment to achieve this goal and have an entire year of data before the treatment.

Again, the energy consumption of the baseline premises is consistently greater than that of the test premises, based on data provided to the project. This is inconsistent with observations made in the Freeman, Sullivan and Co. report.

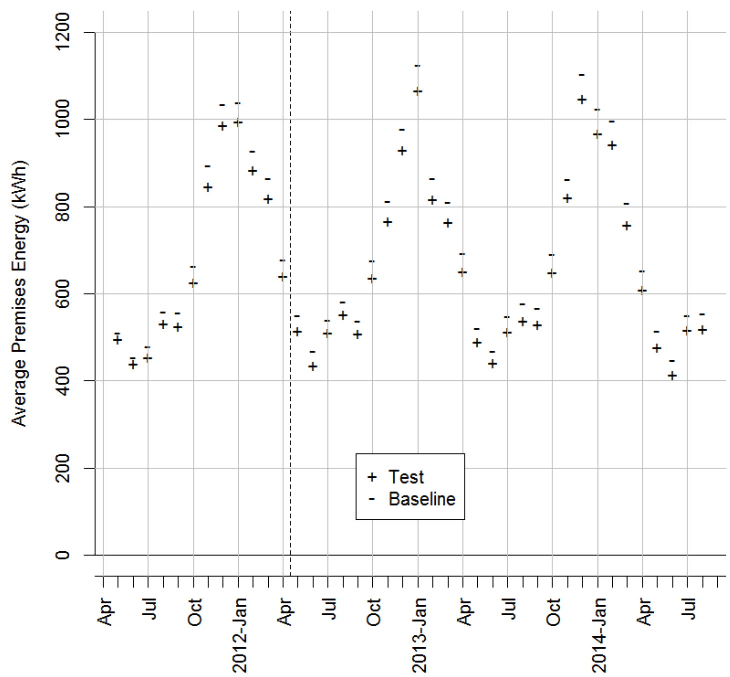


Figure 7.34. Monthly Average Energy Consumption by the Test and Baseline Premises

The monthly energy consumptions from year to year in Figure 7.34 appear to be similar. The sum energy consumption from three consecutive project years has been tabulated in Table 7.14. The years are selected to last from May through April, consistent with the years that were available and used in the project's analyses. The standard errors of the years' energy consumptions were estimated from the standard deviation of the months' energy consumptions that year. The groups' energy consumptions are similar from year to year. The differences between the yearly energy consumptions of the test and baseline groups are persistent and significant.

Table 7.14. Average Premises Energy Consumption of the Test and Baseline Groups over Three Consecutive Project Years

	Average Premises Energy (kWh)	
	Test Group	Baseline Group
May 2011 – April 2012	8246 ± 60	8666 ± 63
May 2012 – April 2013	8158 ± 56	8637 ± 58
May 2013 – April 2014	8310 ± 60	8826 ± 63

Net degree hours, heating degree hours, and cooling degree hours were calculated for each month. Again, caution was used to make sure that the calculations were not adversely affected by missing data intervals. Net degree hours were calculated by multiplying the average difference between ambient temperature and 55°F by the actual number of total hours each month. The “hot” hours add to make the net degree hours greater than zero; the “cold” hours subtract to reduce the net degree hours below zero. The calculation is “net” because many of the positive- and negative-valued intervals cancel one another, especially during shoulder spring and fall seasons.

The distinction between cooling and heating regimes was determined as the temperature at which the two lines that best represent the relationship between both groups’ monthly energies and net degree hours intersected. “Best” here refers to the linear regression model having minimal sum residual error. The intersection occurred at precisely 55°F.

Heating degree hours were determined as 55°F, minus the average of temperatures lower than 55°F, multiplied by the sum number of hours that the temperature was below 55°F that month. A similar calculation was conducted for cooling degree hours, but this calculation used temperatures and time intervals while the temperature was higher than 55°F.

If the sum of heating hours and cooling hours in a month was not equal to the actual hours in a month, the heating and cooling hours were accordingly scaled to make sure that all hours were represented in the heating and cooling degree-hour calculations.

The monthly energy usages of the test and baseline groups have been plotted against their months’ net degree days[1] in Figure 7.35. The legend, in this case, distinguishes both the group memberships and whether the months were before or after the test group’s exposure to web portal information. A vertical dashed line marks zero net degree days (or hours), where the average temperature would have been 55°F. The energy of baseline premises is again shown to be consistently greater than that of test ones. The impact of the treatment is not evident by inspection.

[1] Degree days are degree hours divided by 24.

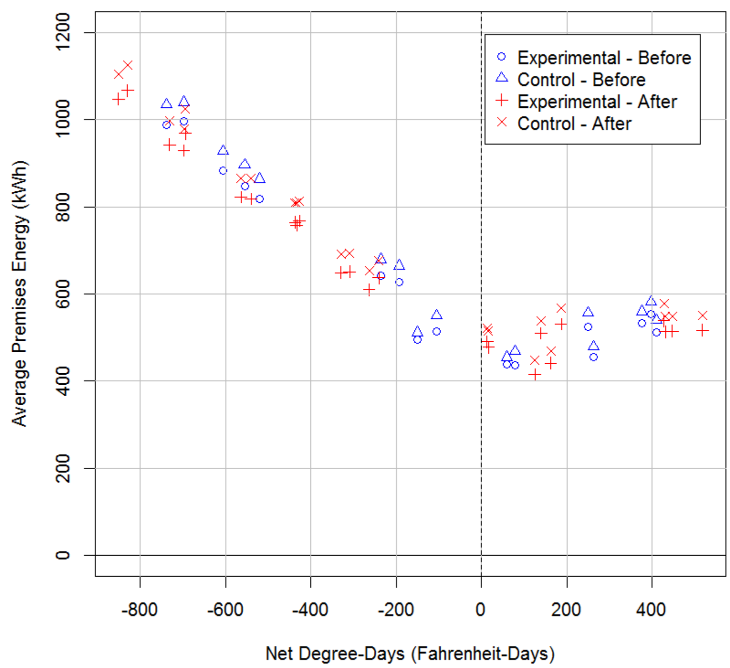


Figure 7.35. Monthly Average Premises Energies as a Function of Net Degree Days

Regression analysis was then conducted from this model. Each group's monthly energy consumptions were modeled using linear regression and R software programming tools (R Core Team 2013). The parameters included heating degree hours, cooling degree hours, and a flag indicating whether the month lay before or after the treatment.

The project first tried to emulate the experimental approach that had been used in the Freeman, Sullivan and Co. report, in which the treatment was stated to have lasted only from April 2012 to April 2013. The treatment flag parameter was modified to indicate this time period, after which all residents were said to have been given access to web portal information.[1] The baseline group's energy usages were calculated to have been reduced by 1 ± 17 kWh per month in the treatment period, and the test group energy was reduced 8 ± 13 kWh per month. The difference between the two changes that might be attributable to the access to web portal information would be a reduction of 5 ± 23 kWh per month. As was the case in the study by Freeman, Sullivan and Co., the change is not statistically significant, but it is a reduction, whereas the early study reported the opposite. If this magnitude were real and significant, it would represent a reduction of about 0.7% of the premises' energy consumption.

The project also performed the regression fit, but while presuming an additional full treatment year until April 2014. Interestingly, the presumption of an additional treatment year made virtually no difference in the end result.

The project was unable to confirm a significant change in energy consumption for residential customers who had been granted access to information from an energy web portal. A small reduction of

[1] It should also be noted that Sullivan et al. had at least another year's worth of historical data to use from 2009.

about 0.7% energy consumption was found, but the result was not statistically significant. An unusual difference between the test and baseline members' average energy consumption was noted. The Freeman, Sullivan, and Co. report observed this difference, too, but in the opposite direction.

The utility internally assessed the monetary impacts of its new AMI system features as follows:

- meter reading savings – $157,000
- customer service savings – $70,000
- servicemen callout reduction – $8,000.

The sum savings was estimated at $235 thousand per year. The project did not review or confirm these savings.

7.6 WSU Bio-Tech Generator for Outage Prevention

Avista Utilities proposed that the 800-kW Bio-Tech diesel generator at the WSU Pullman campus would become responsive to requests from the utility and would assist in outage prevention. The Bio-Tech generator had been installed and configured for parallel operation and might be the main resource in a campus microgrid. A control design was initiated to recommend when parallel operation should commence, but approval was always required from a human site operator.

New Washington State regulations regarding particulate emissions for diesel generators potentially applied to this generator, rendering it unavailable. The asset was not completed.

Table 7.15 lists estimated annualized costs for the system. Automated switchgear hardware was required and installed. It was estimated that almost $50 thousands would be needed each year to control this asset and measure and confirm its operation.

Table 7.15. Components and Annualized Component Costs of the WSU Bio-Tech Generator System

System Component	Component Allocation (%)	Allocated Annual Component Cost ($K)
Evaluation, Measurement and Validation	13	22.8
Automated Switchgear	100	14.0
Project Management Services	13	12.9
Total Annualized System Cost		**$49.7K**

7.7 Configuration Control for Optimization (FDIR)

In addition to the ability of AMI meters to identify faults or outages, Avista Utilities implemented FDIR within its DMS to help it rapidly detect faults and improve its outage recovery process. The premise is that the utility becomes alerted soon after an outage as to which customers are affected. In some instances, the precise fault circuit location is identified. The utility can then respond rapidly and send the right resources to restore customer service, which has an economic benefit for the utility and its customers. The FDIR system was fully automated by August 2013.

Toward this end, Avista Utilities installed four sets of switchgear, 45 distribution line switches, 47 G&W Viper® smart circuit reclosers, and 354 Schweitzer (SEL 2015) smart fault circuit indicators, one at each primary trunk fuse location. These fault circuit indicators report outages to the DMS and the Avista Outage Management Tool (OMT). Most of these devices include voltage and current measurement points, making them even more useful for monitoring circuit status. All installed devices of this system communicate via the 802.11 MAN to RTU devices located in Spokane, Washington.

The utility subcontracted ACS (ACS 2015) to implement its DMS software with the FDIR application. Partner HP also provided integration resources and hardware.

At the beginning of the PNWSGD, Avista Utilities anticipated a decrease in the Customer Average Interruption Duration Index (CAIDI) and an increase in the Momentary Average Interruption Frequency Index (MAIFI) reliability measures. A minimum reduction of 20% was expected for CAIDI. The OMT calculates these IEEE indices, which have been reported to the Washington Utilities and Transportation Commission since 2004, potentially providing a comparison baseline of over six years of relevant reliability indices.

The estimated value that was derived from the application of FDIR was measured by the utility in customer avoided-outage minutes, translated to dollar impacts on customers. During 40 prior months, 24 incidents had led to lockout of service. Those outages corresponded to some 88,210 customer-outage hours that would be valued at $882,100, allowing $10 per customer-outage hour. If 20% of these outages had been avoided, the annual value would be just under $62 thousand per year. Avista Utilities thought they might yield even twice this benefit in Pullman because of its circuit characteristics.

Table 7.16 lists the estimated annualized costs of the FDIR system and its components. The major expenses were an allocation of some of the costs of customer advanced metering and the software upgrades needed for the DMS. The total annualized system costs were estimated to be about $1.4 million.

Table 7.16. Components and Annualized Component Costs of the Avista Utilities FDIR System

System Component	Component Allocation (%)	Allocated Annual Component Cost ($K)	
Advanced Metering Infrastructure		511.9	
• Software and Systems	25		316.0
• Operations and Maintenance	25		100.3
• Residential Equipment			
o Control Group	33		39.2
o Target Group	33		29.7
o Target Group with DR	25		7.1
• Engineering	25		7.7
• Commercial equipment			
o Control Group	33		5.2
o Target Group with DR	33		4.3
o Target Group	25		0.7
• Training	25		1.9
DMS Software and Hardware for 700–1,000 End Points	25	420.8	
Wireless Network	25	173.2	
Automated Line Switches	50	72.6	
Fiber Network Communications	17	53.4	
Smart Transformers Equipped with Sensors, Current Transformers, and Wireless Communications	25	37.3	
Fault Indicators	100	26.8	
Evaluation, Measurement and Validation	13	22.8	
Station Reclosers and Controls	100	20.5	
Project Management Services	13	12.9	
Subcontractor – Integrated Volt/VAr Control Software	33	12.7	
Reconductoring	33	11.8	
Customer Service	25	10.5	
Outreach and Education	25	7.9	
Total Annualized System Cost		**$1,395.4K**	

7.7.1 Data Concerning Pullman Site Reliability

The project attempted to observe improvements in the site's reliability based on the reliability indices SAIFI, SAIDI, and CAIDI that were calculated by Avista Utilities and submitted to the project for each project month. These indices were calculated separately for each of the 13 Pullman, Washington, feeders, but the project's analysis used aggregated indices that had been calculated for all 13 site feeders.

None of the indices were submitted from the months of 2011. The project does not know the reason for this omission.

Figure 7.36 shows the site's SAIFI metric from January 2009 through September 2014. These calculations were completed by the utility for these project months except for 2011. February and March 2009 had unusually high SAIFI values, the magnitudes of which have not been exceeded since.[1] The greatest SAIFI is about 0.75 outages per customer that month. The following months of 2009 had much lower values. The average month's SAIFI for the site is 0.085 ± 0.021 sustained outages per customer over these 57 months. The median is 0.020 sustained outages[2] per customer. These calculated statistics did not include 2011 data.

No improvement in SAIFI should be claimed based on inspection of this figure. In fact, the last project months had larger values than usual. No data was received from 2011.

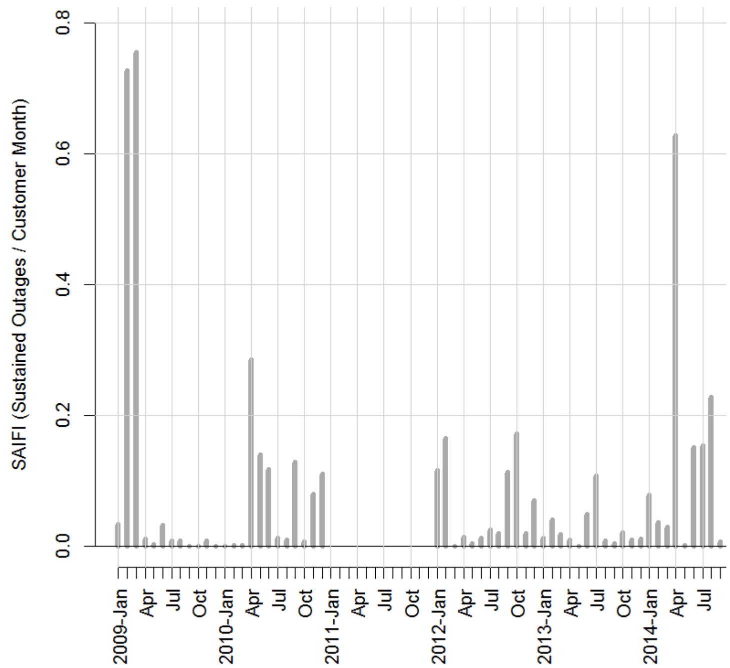


Figure 7.36. Monthly SAIFI Reliability Index for the Combined 13 Pullman Site Feeders

Figure 7.37 shows the calculated SAIDI metric for all of Pullman, Washington, from January 2009 through September 2014. The greatest SAIDI value was 94 minutes per customer in November 2010. The average month's SAIDI in Pullman, Washington, was 8.8 ± 2.3 minutes per customer, and the median was 2.3 minutes per customer per month. Again, no calculations were supplied for 2011.

[1] An analyst researched these months and found that there had been exceptional storms those months—an ice storm February 26, 2009 and a wind storm March 15, 2009.
[2] A "sustained" outage is almost always defined as one that exceeds 5 minutes.

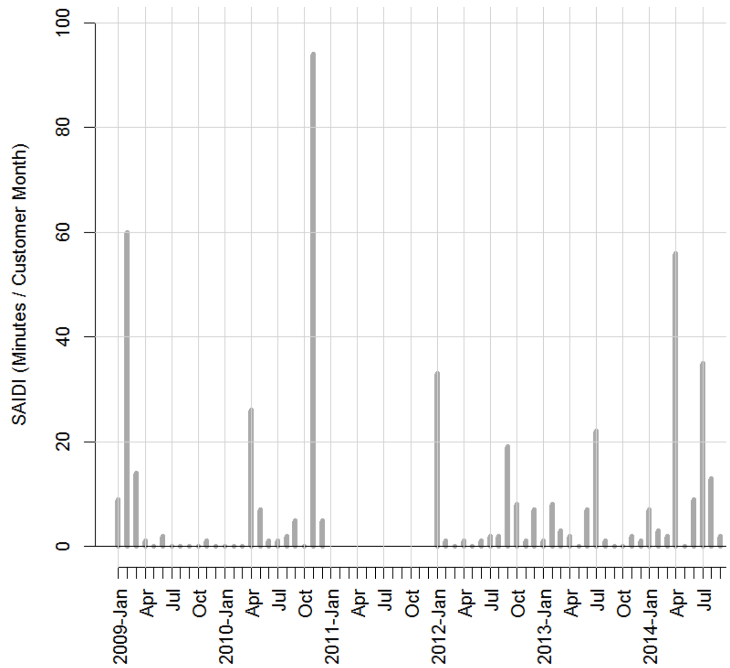


Figure 7.37. Monthly SAIDI Reliability Index for the Combined 13 Pullman Site Feeders

Figure 7.38 shows CAIDI for all of Pullman, Washington. A very large, uncharacteristic spike occurred in November 2010, when the typical customer outage was over 19 hours long. The cause of these outages was a wind storm November 16–17, 2010. The average of the months' CAIDI was 141 ± 21 minutes per outage. The median of the monthly values was 103 minutes per outage. The utility believe that had FDIR been in place, the numbers for this event would have been greatly reduced. By inspection, with the exception of the very large spike for November 2010, the CAIDI values have become greater, not less, toward the end of the project. However, the utility reports that it has had no events in Pullman during the PNWSGD that have locked out service. Therefore, no FDIR responses have become initiated during the PNWSGD.

No indices were submitted by the utility for 2011.

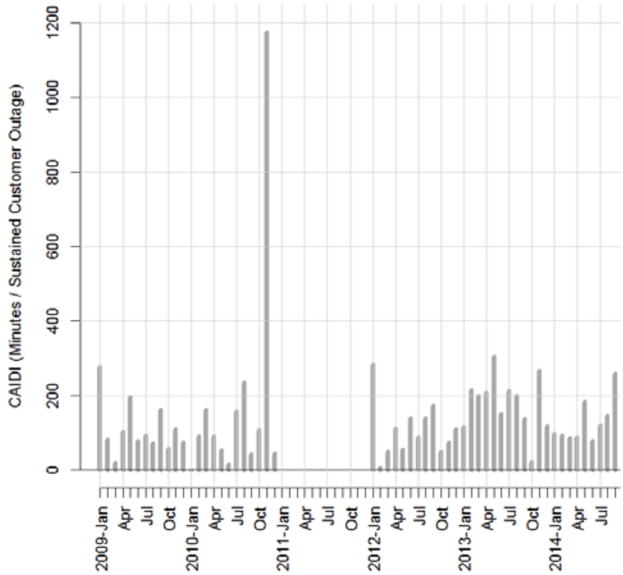


Figure 7.38. Monthly CAIDI Reliability Index for the Combined 13 Pullman Site Feeders

Recloser switches are critical components of the FDIR system, so the project reviewed a sample of recloser switch operation counts that had been submitted by Avista Utilities. Table 7.17 lists the aggregated counts by season for three of the South Pullman feeders—SPU121, SPU123, and SPU125. Data was listed only when the project had complete data for the seasons. The table also includes the sum count from the three feeders.

An exceptional number of recloser switch operations occurred during March 2012 on Feeder SPU123. There might be weak trend for fewer recloser operations during summers, but winter 2013 also had few operations. The use of smarter fault detection and recovery does not appear to be adversely affecting the counts of recloser operations. The utility confirmed that they had not observed any change in recloser operations. Anecdotally, the numbers of service lockouts has been small, but this fact might be attributable to weather.

Table 7.17. Recloser Operation Counts by Season for Three Representative South Pullman Feeders

	Feeder			
Season	SPU121	SPU123	SPU125	Total
Spring 2012	28	2,579	8	2,615
Summer 2012	2	70	0	72
Fall 2012	30	20	40	54
Winter 2012	48	36	12	96
Spring 2013	48	36	12	96
Summer 2013	4	0	0	4
Fall 2013	32	24	6	62
Winter 2013	0	0	20	20
Spring 2014	17	12	4	33

7.7.2 Analysis of Pullman Site Electricity Reliability

Given that reliability indices are highly variable over time, the project has developed an objective method to observe whether significant changes might have occurred in a time series of index data. The method separates the indices by whether they occurred before or after a given data interval—a month, in this case. The populations of indices on the two sides of the time demarcation are treated as independent sets, and Student's t-tests are applied to objectively compare the two populations. The process marches through the successive months and reports whether the indices in the following months have a significantly reduced value when compared against the preceding months. This may be novel to the project and should be considered as a practice to continuously observe whether changing distribution utility practices are improving or harming customer service.

Figure 7.39 is the result of such analysis, where these results are based on the SAIFI metrics that were shown in Figure 7.36. The first SAIFI values from early 2009 had been unusually large. Therefore, this analysis approach determined that SAIFI had, indeed, improved. The vertical axis represents a statistical p-value, in this case interpreted as the percent likelihood that following months' SAIFI value is smaller than in previous months. A horizontal, dashed red line has been placed on the figure to indicate the normal threshold at which one may have 95% confidence in the premise. Conversely, the red dashed line at 5% suggests the threshold at which the latter months' indices appear to be *greater than*, not smaller than, the indices of the preceding months.

The SAIFI performance was so good in the second half of 2009 that the calculated trend projected that SAIFI was becoming worse in the future. The t-test discounted the impacts from the two initial spikes, concluding that these were possibly outliers. In the remainder of the project, the method indicated the index was neither improving nor degrading. The fact that the likelihood values remain in the bottom half of the range suggests that SAIFI values are tending to become slightly worse.

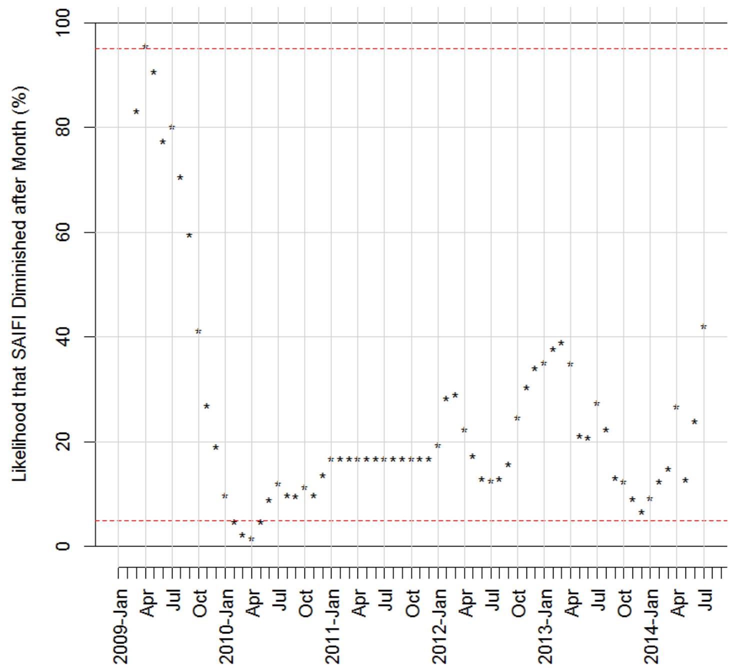


Figure 7.39. Likelihood that the SAIFIs for the following Months are Significantly Lower than those in the Preceding Months

The methods used to create Figure 7.40 are the same as was described above, but this figure is based on the site's monthly SAIDI indices. The sawtooth patterns on the two sides of 2011 were likely caused by the uncharacteristic peak index for November 2010. At no time does the likelihood exceed the 5% or 95% thresholds. No change can be confidently stated concerning the utility's management of SAIDI these months. The downward trends through much of 2012 and 2013 are troubling.

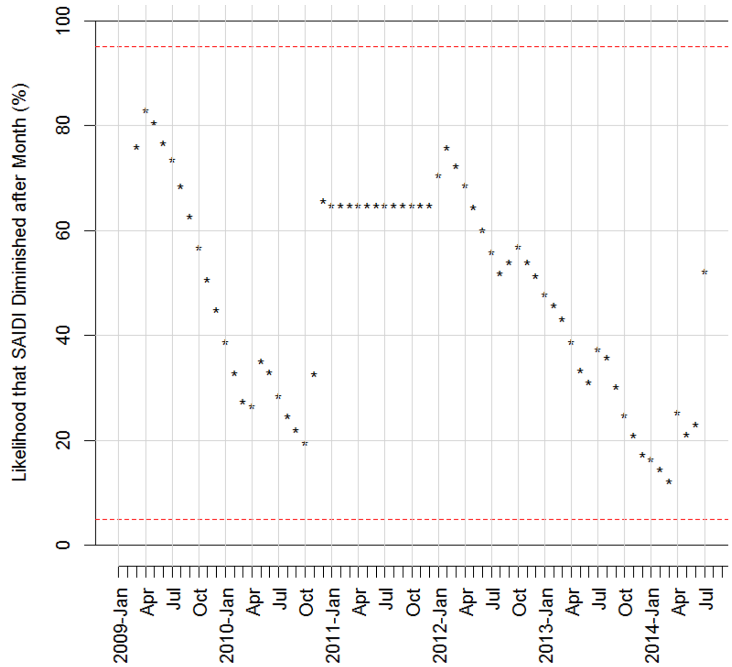


Figure 7.40. Likelihood that the SAIDIs for the following Months are Significantly Lower than those in the Preceding Months

The same analysis methods were applied in Figure 7.41 as the project reviewed trends in the CAIDI metric. The likelihood was strongly affected again by a peak CAIDI value in November 2010. While this outlier remained in the future, the method concluded that the index was getting worse. As soon as the peak month was in the past, the method's output jumped to a more reasonable likelihood value. The likelihood rose and fell predictably, based on what had been observed in Figure 7.38, but the t-tests never closely approached thresholds at which convincing changes could have been verified.

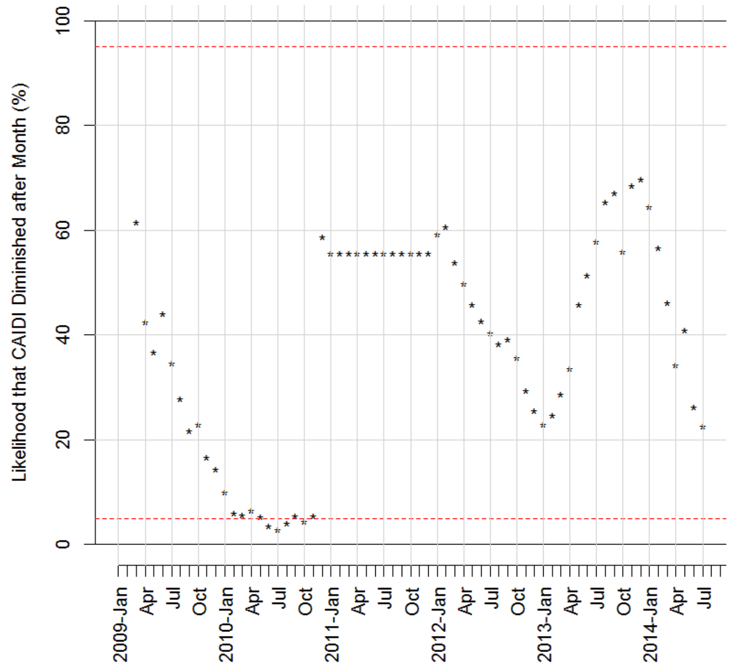


Figure 7.41. Likelihood that the CAIDIs for the Following Months are Significantly Lower than those in the Preceding Months

The project was not able to verify that the new FDIR system, or any other distribution management practices, for that matter, had significantly impacted the CAIDI reliability index that had been targeted for improvement. Similarly, no significant improvement in the site's SAIFI or SAIDI indices could be verified. Avista reported substantial improvements in reliability with 353,336 avoided outage minutes for customers beween August 2013 and December 2014. Customers also experienced an annual average of 17 percent fewer outages and more than 12 percent shorter outages during the same time period. Further, Avista believes a lack of severe weather-related outages during the grid demonstration project prevented full exercising of the FDIR system.

7.8 Controllable HVAC Fan Load at 39 Campus Buildings

The negotiated interaction between Avista Utilities and the WSU campus, including system integration was performed by Spirae. (Spirae, Inc. 2015), was documented in the Spirae-Washington State University Interface Control Document.[1] This document defined five response tiers that corresponded to five campus assets, of which Avista would be allowed to request control:

- Tier 1 – HVAC load shed (discussed in this section, 7.8)
- Tier 2 – Chilled water load shed (discussed in Section 7.9)

[1] Unpublished engineering document authored by Spirae, Inc., 320, East Vine Drive, Suite #307, Fort Collins, CO 80524, USA. Last known version 1.5 was revised April 6, 2015.

- Tier 3 – Grimes Way steam plant diesel generator dispatch (discussed in Section 7.10)
- Tier 4 – Grimes Way steam plant first natural gas generator dispatch (discussed in Section 7.11)
- Tier 5 – Grimes Way steam plant second natural gas generator dispatch (Section 7.11).

These assets were to remain under manual control. The campus's assets may at times be unable to change their operations upon receipt of requests from the utility. The parties defined a set of four signals with which responses could be requested, acknowledged, and informed between the parties:

- Avista-generated request signal (AGRS)—a utility request to the campus for the engagement of one of the asset "tiers"
- AGRS acknowledgement signal—the campus's acknowledgement upon receipt of an AGRS request from the utility
- AGRS response signal—further indication from the campus back to the utility that the campus either intends to act on the request or cannot respond
- Asset active signal—confirmation from the campus to the utility that the asset is indeed responding.

As described, the process may be initiated by Avista Utilities. The PNWSGD project had asked that the requests to the campus be made responsive to the transactive system. Transactive toolkit functions were established and configured for each of the five tiers. The utility was invited to further define its own objectives for the Pullman, Washington, site, which would have further refined the times at which the transactive system would have advised responses.

The five university assets were initially treated as a single asset system by the project. Table 7.18 lists the estimated annualized costs needed to make the five campus assets responsive to Avista Utilities and the PNWSGD project's transactive system. As these campus asset systems are discussed in the remaining sections of this chapter, the reader will be referred back to this table.

Table 7.18. System Components and Annualized Costs for the Combined WSU System, Including Controls of HVAC Load, Chiller, Diesel Generator, and Two Gas Generators on the WSU Campus in Pullman, Washington

Asset System Component	Component Allocation (%)	Allocated Annual Component Cost ($K)
Transactive Node System	33	114.4
WSU Engineering Labor	100	60.1
Evaluation, Measurement and Validation	13	22.8
Project Management Services	13	12.9
Outreach and Education	25	7.9
Total Annualized Cost		**$218.1K**

The remainder of this section addresses only Tier 1, concerning control of 39 HVAC systems on the WSU campus. Early in the project, the utility estimated that 145–552 kW of daytime load could be reduced in the summer by changing the operation of campus HVAC circulation fan systems. In winter, daytime power was projected to be reducible by 345–369 kW.[1]

Some conservation was anticipated through reduction of fan energy during unoccupied building hours. Unoccupied hours are typically considered 19:00 to 06:00, but may vary by building.

Because the utility had additionally requested demand responses for up to 50 hours per year, the campus planned to cycle through available HVAC fan loads upon receiving these requests, including during buildings' occupied periods, for short, 15–20-minute periods. They estimated that total fan loads could be reduced about 25% without adversely affecting air quality for the buildings' occupants. The requested reductions were to last 15, 30, or 60 minutes. Subsequent requests were not allowed within 3–4 hours after the prior event had concluded.

7.8.1 Data Concerning Control of the WSU HVAC Fan Loads

The project reviewed the statuses of the four DR signals that had been developed collaboratively by Avista Utilities, WSU, and Spirae. The AGRS turned out to be more of a permissive signal than targeted DR requests were. The signal remained fixed in its active ("1") state or in the special status, "Engagement with transactive control." In the end, there were only 39 5-minute intervals when all four signals were in their active ("1") states. The status of the final indicator alone—the active signal confirmed by WSU—was adequate to indicate whether the fan power reduction should be active or not.

The system was exercised only four months during 2014—January, February, June, and July. Two-thirds of the events occurred during February 2014.

The 39 intervals represent 3 hours and 15 minutes of engagement, spread over 12 event periods. These 12 events' starting times and durations are listed in Table 7.19. The shortest duration was 5 minutes; the longest, 30 minutes. The average duration was about 17 minutes. The events occurred exclusively on work weekdays between 10:35 and 15:50 local Pacific Time.

[1] These power reduction estimates and further information here about the anticipated response of the WSU HVAC system were found in the unpublished project document, Avista Utilities Subproject Description.

Table 7.19. Times and Durations of the Twelve Events when WSU HVAC Fan Usage was Reduced

Event	Year	Month	Day	Day of Week	Local Starting Time (hh:mm)	Duration (h:mm)
1	2014	Jan	30	Thursday	10:35	0:05
2	2014	Feb	6	Thursday	13:50	0:05
3	2014	Feb	7	Friday	13:05	0:15
4	2014	Feb	11	Tuesday	10:00	0:15
5	2014	Feb	12	Wednesday	13:50	0:15
6	2014	Feb	19	Wednesday	10:00	0:15
7	2014	Feb	20	Thursday	11:00	0:15
8	2014	Feb	21	Friday	12:00	0:15
9	2014	Jun	9	Monday	13:55	0:15
10	2014	Jun	23	Monday	15:05	0:30
11	2014	Jun	24	Tuesday	15:20	0:30
12	2014	Jul	28	Monday	12:20	0:30

Avista Utilities compiled a set of WSU campus meter readings for the observation of impacts from the 39 campus HVAC systems. McKinstry installed these meters for the utility and campus. Five-minute aggregated power data was supplied to the project covering a period from late April 2013 until September 2014. This data time series is shown in Figure 7.42. Data quality was generally good, but the data was found to have “stuck” on nonzero values throughout much of December 2013 and January 2014. These “stuck” intervals were removed from the data set prior to analysis and are not shown in the figure.

The power data has a strong weekly pattern. Power consumption was significantly reduced on weekends. Upon focusing in on individual months and weeks, analysts also observed very different consumption patterns on national holidays and certain other days, such as the Friday following Thanksgiving Day. By simple inspection, the four calendar months for which both 2013 and 2014 data exists are different. Power consumption in 2014 appears to have increased significantly above the levels in 2013.

Based on all the reported power data, the average power consumption was 2.795 ± 0.002 MW. The standard deviation of the power measurements was 0.56 MW.

The effect of temperature on power consumption, though noticeable, was small.

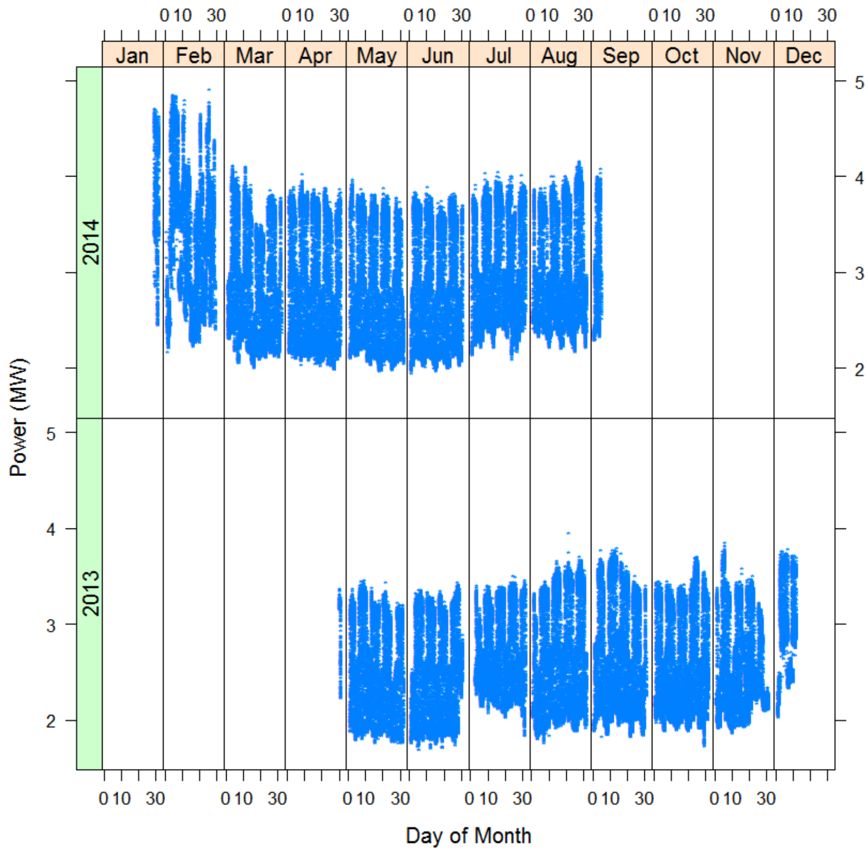


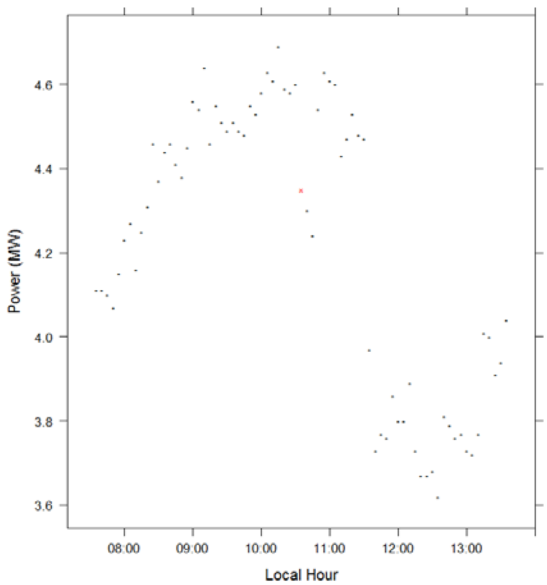
Figure 7.42. Power Data Supplied to the PNWSGD by Avista Utilities from which WSU HVAC Fan Reductions were Analyzed

7.8.2 Analysis of the WSU HVAC Fan Loads

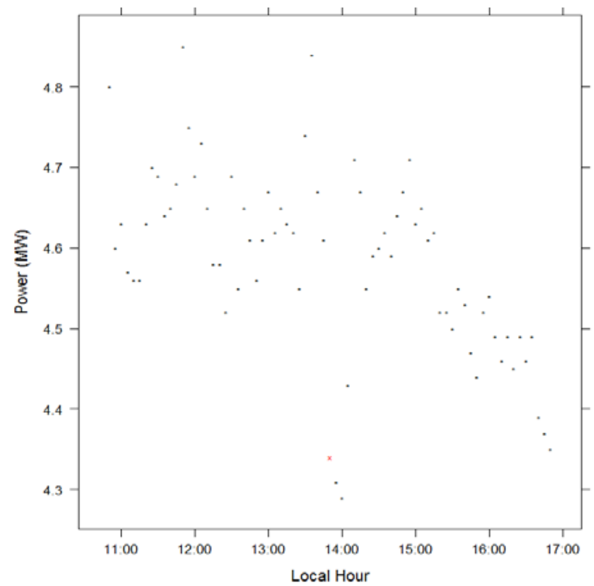
The power consumption during the 12 events, plus and minus about 3 hours each side of the event, are shown in Figure 7.43. This time series is the same that had been shown in Figure 7.42 above, but only narrow time windows around each reported event are shown in the panels of Figure 7.43(a-l). The power during event intervals is marked by a red “x,” as is shown in the single legend in the last panel (l).

It was reassuring to analysts that the reduction in load was often evident by inspection of these plots. The only exception is Event 10, Panel (j), where no event intervals appear to have reduced power. However, a reduction of similar magnitude and the right duration appears to have occurred one hour earlier that event. It is likely that the time of that event was misreported by one hour. By inspection, the power reductions appear to be typically on the order of 0.2–0.3 MW.

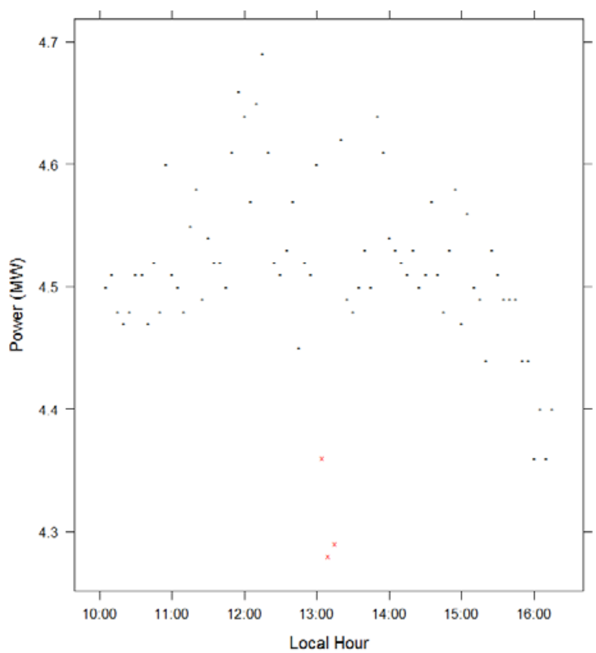
Other events in this set also appear to include reporting errors. For Events 1 and 2 (Panels (a) and (b)), power reduction appears to have extended beyond the intervals that had been reported. Event 12 (Panel (l)) appears to have been terminated earlier than was reported. All these types of reporting errors could adversely affect verification of the impacts of demand responses using this DR asset.



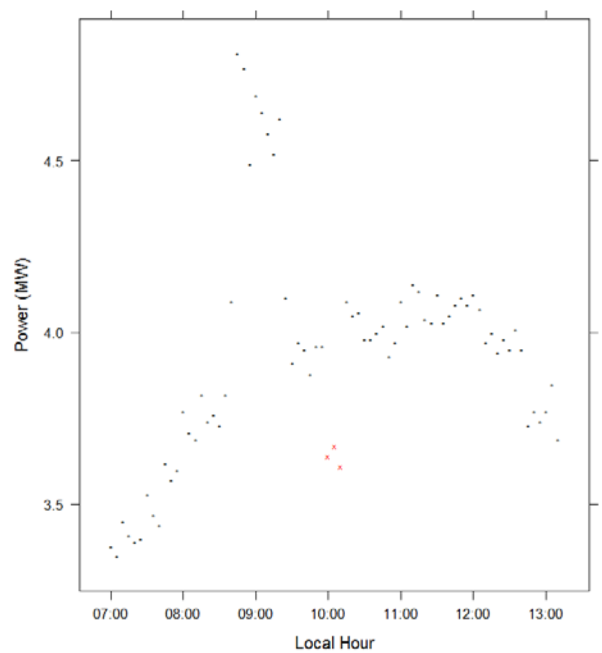
(a) Event 1: January 30, 2014



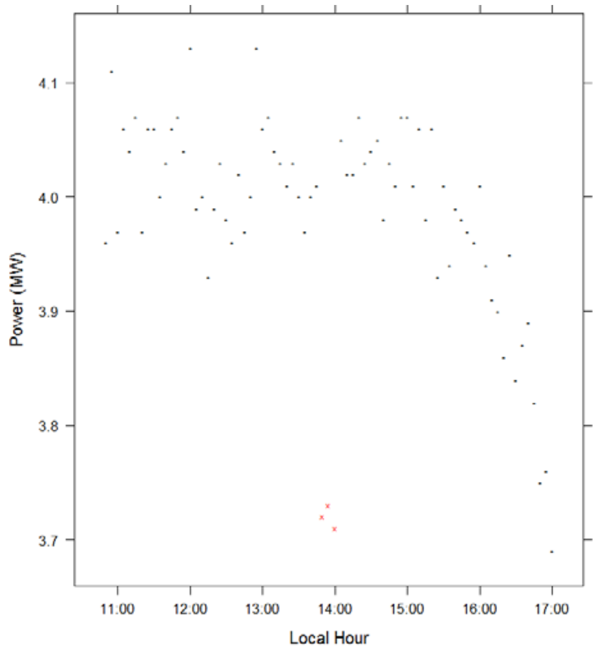
(b) Event 2: February 6, 2014



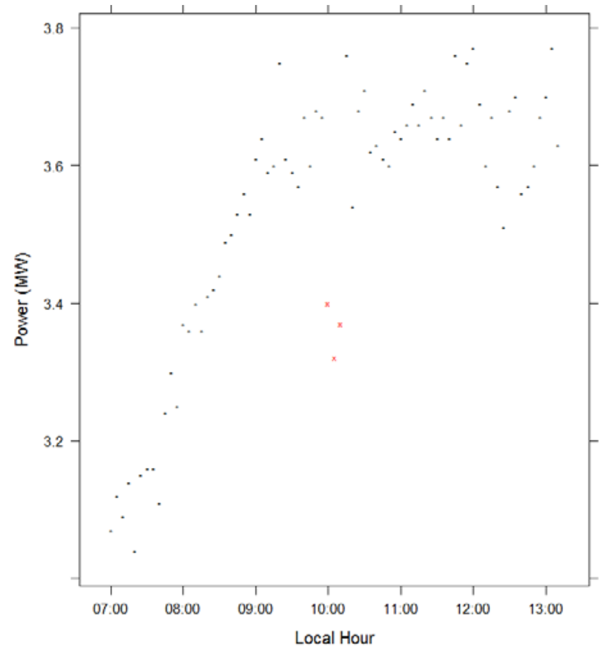
(c) Event 3: February 7, 2014



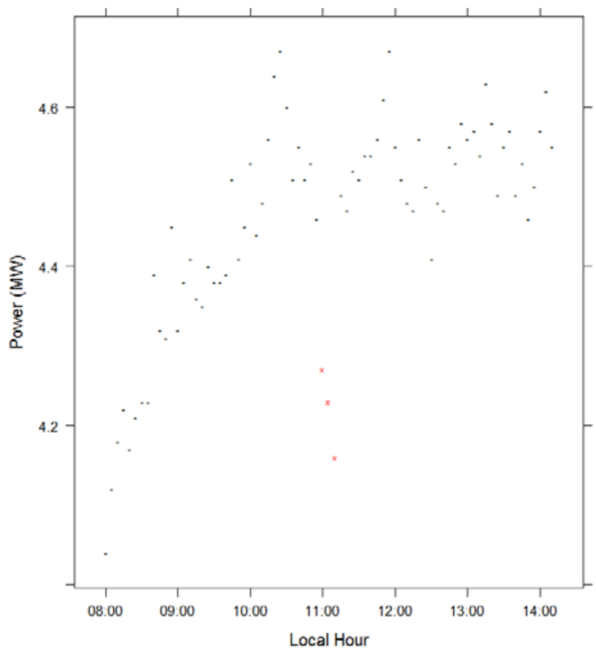
(d) Event 4: February 11, 2014



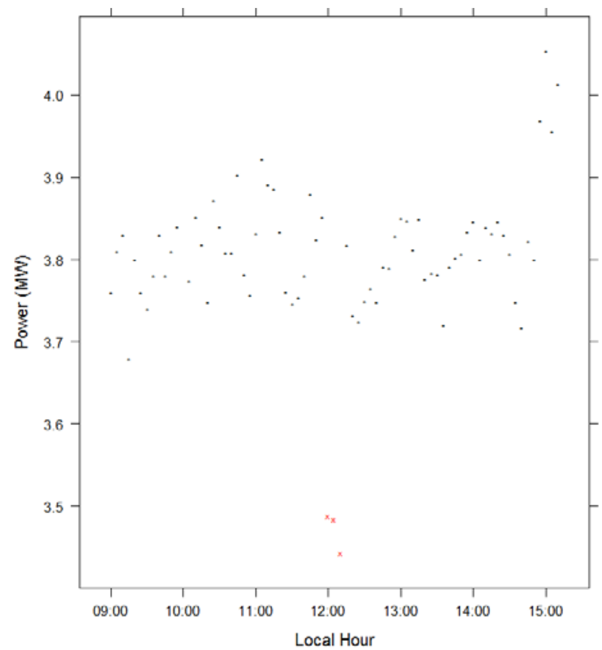
(e) Event 5: February 12, 2014



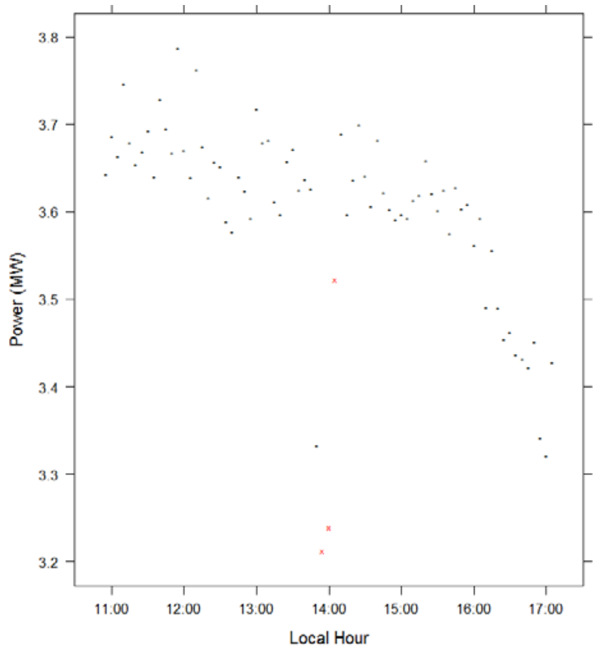
(f) Event 6: February 19, 2014



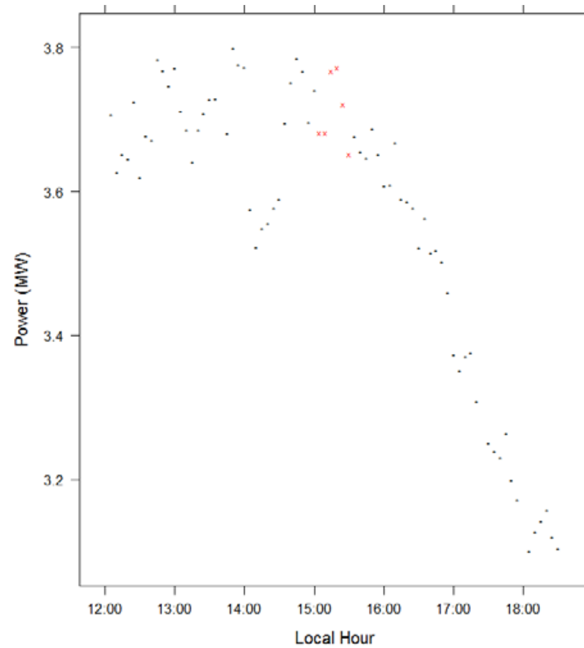
(g) Event 7: February 20, 2014



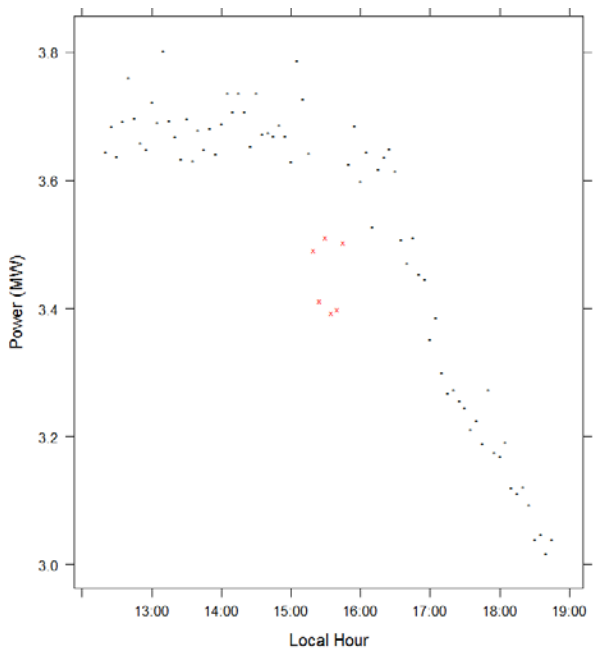
(h) Event 8: February 21, 2014



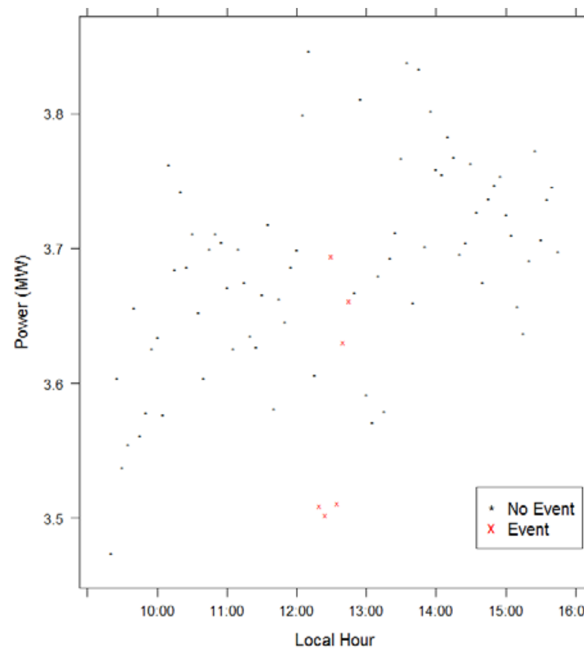
(i) Event 9: June 6, 2014



(j) Event 10: June 23, 2014



(k) Event 11: June 24, 2014



(l) Event 12: July 28, 2014

Figure 7.43. Power Time Series from 3 Hours Prior to the Reported Reduction in WSU HVAC Fan Load to 3 Hours after the Events. Event data intervals have been marked and colored differently according to the legend that is shown in the last panel (l).

To more rigorously quantify the magnitude of the HVAC fan power reductions, project analysts created a regression model of the reported power time series. The regression model was greatly improved and simplified after some interesting characteristics of this time series had been identified. First, the aggregated power on the campus was significantly reduced during weekends. Fortunately, no events occurred during weekend days, so weekends may be omitted from analysis. Holidays, too, were found to have very reduced and different consumption patterns. Additionally, consumption during days surrounding holidays, such as the day after Thanksgiving Day, were abnormal. Again, no events occurred on these days, so they could be omitted from analysis. There was no clear impact evident from the changes between student semester terms and student vacation periods. Removal of weekends and abnormal days was probably more impactful that temperature for this aggregated power time series.

The importance of considering day types and holidays for this analysis is demonstrated by Figure 7.44. In this figure, daily power load has been plotted a function of local time of day, Pacific Time. The days of the week have been shown in seven panels from left to right. The special days, including weekends, holidays, and days following holidays, are plotted in the top seven panels. The remaining "normal weekdays" are plotted in the bottom seven panels. The patterns are remarkably similar for the "normal" weekdays, although there might be a small reduction on Fridays. The data has been further parsed by season, which shows the remaining seasonal and temperature dependence of the data.

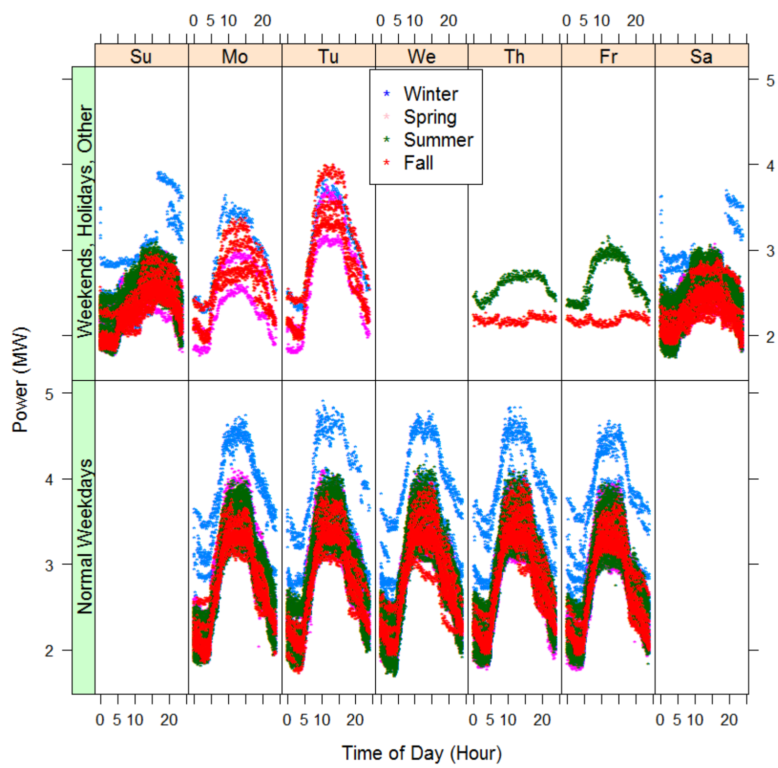


Figure 7.44. WSU Power Data as a Function of Time of Day, Grouped by Weekday and Season. The data for "normal weekdays" (bottom strips) is quite regular and predictable after weekends, holidays, and other unusual workdays have been excluded (top).

Only the “normal weekday” data was used for the regression analysis. A linear regression model was created in software tool R as a function of temperature and by event status, year, month, and hour. Fitting to year was determined to be necessary because the power levels in 2014 were significantly greater than those in 2013. The reason for this load growth is not known to the analysts. The regression fit was strong. Based on the regression that R performed on this data, the impact of events was a power reduction of 239 ± 21 kW.

The regression model was then used to create a comparison baseline that emulates the aggregated power as if the events had not occurred. The baseline was in good agreement with the measured power levels, as is demonstrated by Figure 7.45.

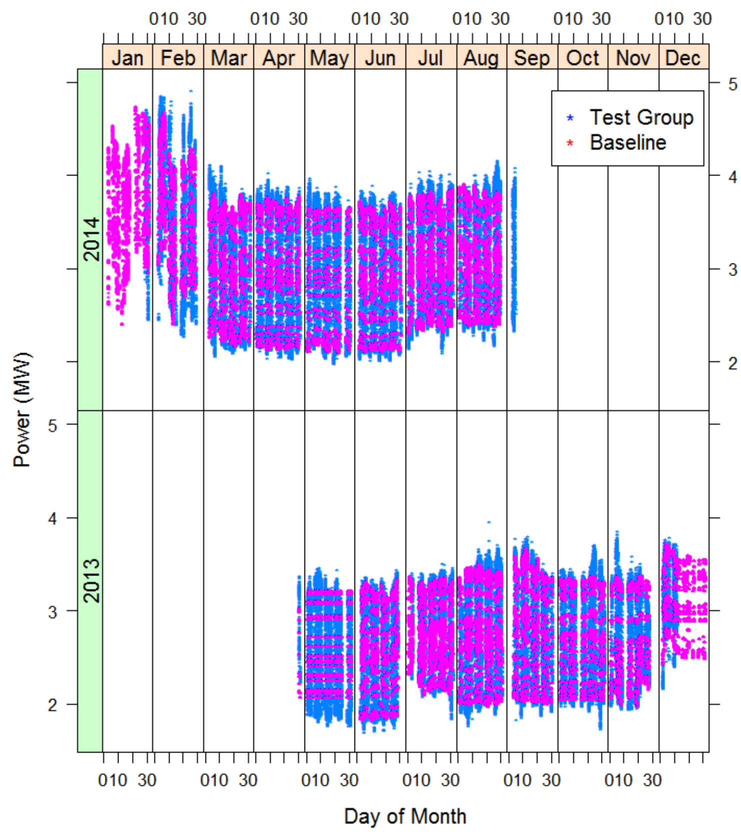


Figure 7.45. Power Measurements and the Modeled Power Measurements that Resulted from Regression Analysis

Student’s t-tests were then used to compare the change in power during events against the change in power during non-event periods. The change in power here refers to the difference between the measurements and the baseline modeled powers. The impacts during events, during the rebound hour following events, and during entire event days were analyzed using Student’s t-tests.

Based on a Student’s t-test comparison between measured power and the regression fit on this power time series that emulates having no events, power was reduced by 239 ± 41 kW during events, on average. The 95% confidence interval is estimated to be from −157 to −321 kW. This estimate reproduced the average magnitude that had been stated by the R model, but the variability was more conservatively calculated. The average magnitude of the power impact is probably conservatively estimated here because of the multiple instances of misreported event periods, as was discussed in Section 7.8.1.

The system was active during only four calendar months, but the impact during these months has been estimated and is shown in Table 7.20. The estimated conserved energy is simply the product of the numbers of hours that the system was reported to have been reducing HVAC fan usage multiplied by the estimated reduction in fan power during the events.

Table 7.20. Estimated Impacts on Power and Energy during Times that the HVAC Fan Usage was Reduced, by Month and for All Months

	Duration (h:mm)	Δ Power (kW)	Δ Energy (kWh)
January	0:05	−14.6	−1.22
February	1:35	−354 ± 72	−561 ± 114
…	-	-	-
June	1:15	−109 ± 43	−136 ± 54
July	0:30	−236 ± 38	−118 ± 19
…	-	-	-
All Months	**3:25**	**−239 ± 41**	**−816 ± 140**

A similar analysis was conducted to estimate any rebound impact that might have occurred during the hours that followed the conclusions of the 12 reported events. No rebound impact should be reported because the impact was not statistically meaningful. The rebound impact might be anywhere between an increase of 32 kW and a continued reduction of 49 kW (i.e., between −49 and +32 kW), based on an estimated 95% confidence interval.

Analysts further looked at the overall impact when comparing days that events had and had not occurred. Surprisingly, a small but significant power reduction was observed throughout days that events had occurred compared with power consumption on days that events had not occurred. On average, the reduction was 43 ± 4 kW throughout these event days. This is about 1.5% of the average aggregated power measurement. Because the typical event lasted only about 17 minutes, the reduction in power during events can account for only several of these average kilowatts during event days. Perhaps other measures may have been taken on these days, in addition to the reduction of HVAC fan loads, to further reduce consumption at the WSU buildings where these measurements were taken.

In conclusion, the project was able to confirm that significant load reduction accompanied the reduction of campus HVAC fan loads. The estimated magnitude of the power reduction closely matched the magnitude that had been anticipated by Avista Utilities early in the PNWSGD project. The project's estimates may be conservative because of occasional misreporting of event periods, which misreporting would also affect the utility's efforts to validate DR from this and other WSU assets. Avista Utilities estimates that energy had been reduced 1,500–3,000 MWh per year through the more efficient management of the WSU air handlers, a reduction worth $87,500–$175,000.

7.9 Nine WSU Controllable Chiller Loads

Avista Utilities and WSU identified nine building chiller loads that could be made responsive to DR requests from the utility. The chillers are used to cool campus buildings. The load can be deferred for short periods without noticeably affecting the comfort of building occupants. The collaboration between Avista Utilities, WSU, and Spirae to request, acknowledge, and confirm the response from this and four other assets was described at the beginning of Section 7.8. The controllable WSU chiller load was the second tier of the five controllable WSU assets within the engineering design documentation.

WSU would allow its chiller loads to be deferred for 30 or 60 minutes. After a successful event, the chillers require 1 hour to recover and recool their building spaces.

The project requested that the demand responses be aligned with the automated requests from the transactive system at the Pullman site. The utility was invited to configure the toolkit function that represented this asset so that it would automatically request responses at the times the utility desired.

The annualized costs for the control of this asset were included in Table 7.18.

7.9.1 Data Concerning the WSU Controllable Chiller Loads

There were five events during the project when WSU confirmed that they had decreased chiller load. According to the signal handshakes that had been established between the utility, campus, and system integrator Spirae, all four signals were necessarily set to "1" for a successful DR event. The project had expected to see targeted utility requests for these responses, but the utility's requests remained in a permissive state much of the time. The status of the confirmatory "active" signal from the campus was adequate to track whether the chillers had, in fact, become engaged.

The starting times and durations of the five events are listed in Table 7.21. The first event, in September 2013, was only 10 minutes long and was probably a test of the system. Each of the remaining four events was conducted in June 2014 and was 1 hour long.

Table 7.21. Starting Times and Durations of the Five Events Reported to the Project Concerning WSU Controllable Chiller Loads. The first appears to be a test event.

Event	Year	Month	Day	Day of Week	Local Starting Time (hh:mm)	Duration (h:mm)
1	2013	Sep	3	Tuesday	15:45	0:10
2	2014	Jun	5	Thursday	14:10	1:00
3	2014	Jun	9	Monday	12:00	1:00
4	2014	Jun	23	Monday	14:00	1:00
5	2014	Jun	24	Tuesday	15:10	1:00

Avista Utilities submitted a series of aggregated power measurements that included the chiller loads. Data was collected from late April 2013 to September 2014. This data is shown in Figure 7.46. As one might expect, the chiller load is very seasonal. It falls to almost nothing from late fall through early spring. The load is active some of the day during shoulder months, and the load is quite large throughout summer days.

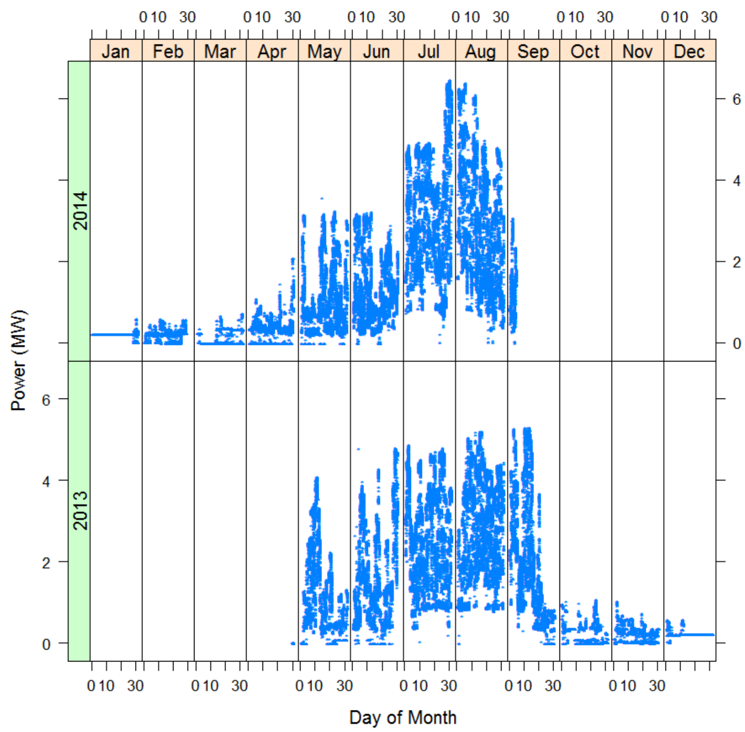


Figure 7.46. Aggregated Power Data Time Series of 5-Minute Data Supplied to the Project Concerning the Controllable WSU Chiller Load

7.9.2 Analysis of the WSU Controllable Chiller Loads

The first event was considered a trial engagement. Project analysis narrowed the investigation to June 2014, the month the remaining four events had been reported. Figure 7.47 displays the aggregated chiller load for all the days of June 2014. The reported event periods are colored red. Even at this resolution, some load reduction is evident.

However, the diurnal patterns of the load are quite irregular, perhaps not easily predictable. Discontinuities occur in midafternoons, when the load jumps 1 MW or more. The load as abruptly returns to lower levels in the evenings. The jumps and drops in load do not happen in the same hours during the month. The unusually low, flat power load in the middle of the month was confirmed to correspond with relatively cold days that month. The last days of the month did not return to the patterns of the first days, even though the temperatures in late June became similar to those of early June. Summer school sessions were launched and continued through this month, so it did not seem that the different patterns could be attributed to different building occupancies.

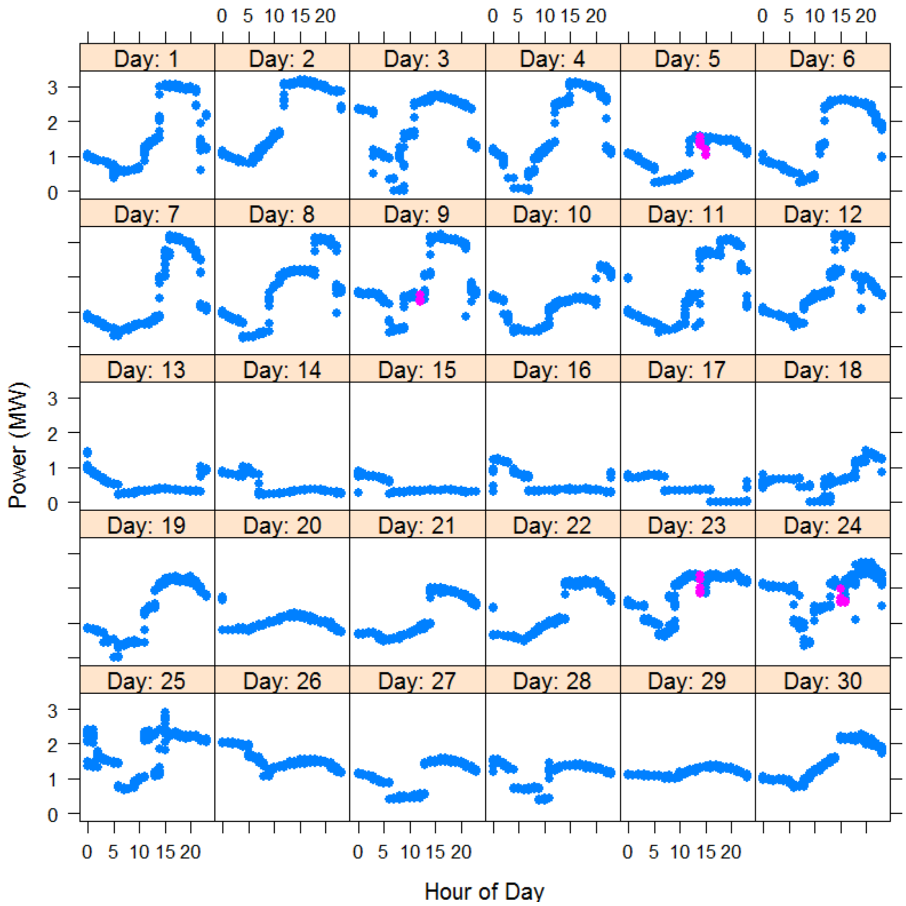


Figure 7.47. Aggregated Power Time Series for Days of June 2014, when the Events were Reported to have Occurred. The event periods have been colored red.

An interesting representation of chiller load emerged when the project tried to understand the connection between local hour of day, ambient temperature, and the aggregate chiller loads. Figure 7.48 is a contour plot of the aggregate chiller load as functions of local hour (horizontal axis) and ambient temperature (vertical axis). All available data was used in creating this graphic, including months of cold Pullman, Washington, weather that were uninteresting and were cropped from the bottom of the figure. If a trajectory of paired hours and temperatures is tracked for any given day, the trajectory's path through the contours creates a decent model of the power that the chillers consume, in aggregate. There will be inaccuracies to the degree that the discontinuities may create variability in the modeled power.

What this all means for the analyst is that the chiller power is extremely difficult to predict or model accurately.

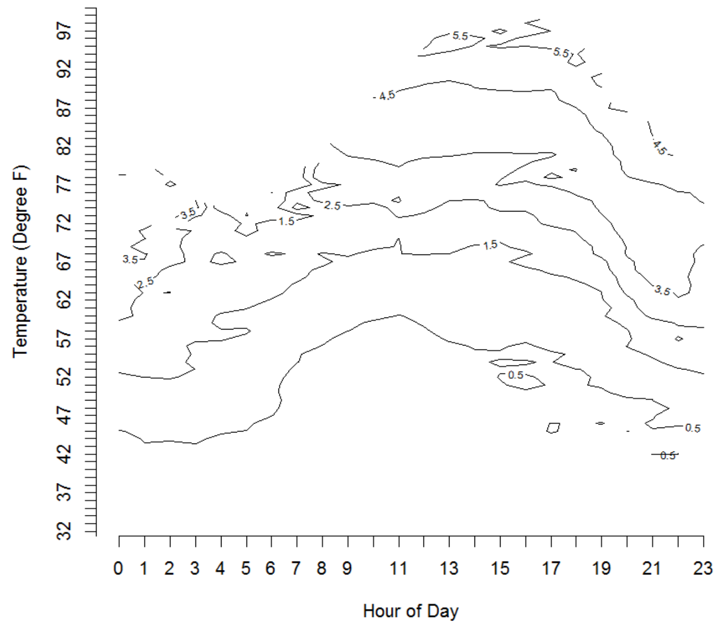


Figure 7.48. Contour Plot of Aggregate Chiller Power (MW) as Functions of both the Local Hour (Pacific Time) and Ambient Temperature

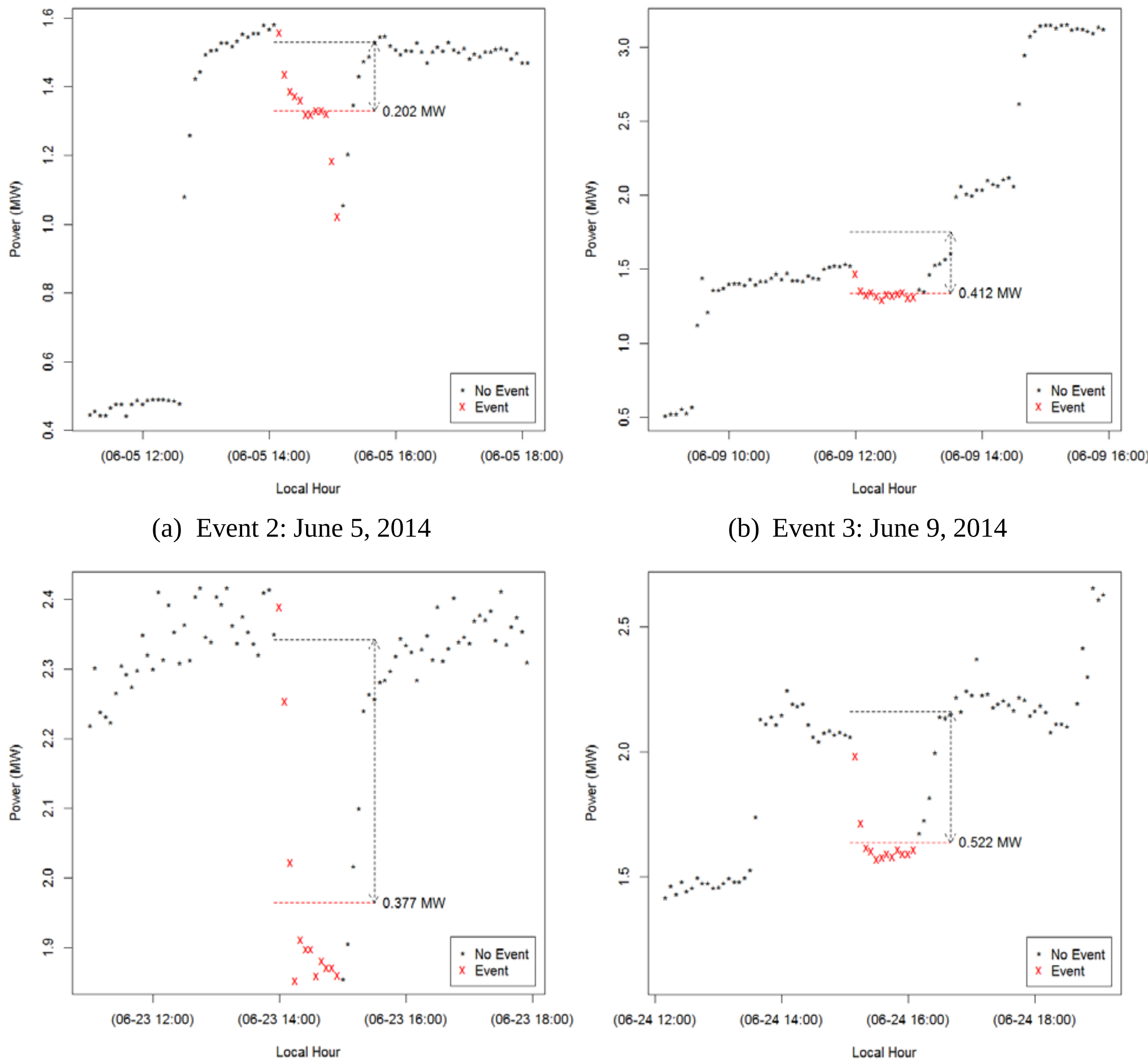
Reluctantly, analysts explored using a notch approach, a direct measurement of the change in power that occurs during events. Such methods are notoriously subjective, but proved fruitful for estimating the impact of the WSU chiller events.

Figure 7.49 focuses still more narrowly on the event periods and the 3 hours before and after the events. The four June 2014 events are shown. Data during the reported event periods is indicated by a red "x." Power reductions are evident by inspection.

Some delay is evident in the initiation and termination of the events, based on the notched power reductions. It appears to take about 15 minutes (three 5-minute data intervals) before an event achieves its fully reduced power level. When the event is terminated, it takes about 35 minutes (seven 5-minute data intervals) before the power returns to the higher, normal power level.

Dashed red lines were drawn at the average event power levels in Figure 7.49, using all the reported event intervals in the averages. Dashed black lines were generated to estimate the normal power level, and each of these lines is the average of the aggregated power levels from 1 hour before the first event interval to another hour duration that began between 35 and 95 minutes after the last event interval had ended. The power differences between the two lines are shown for each event.

The precise method for defining the two levels was subjectively determined and is arguable. Regardless, the representations appear reasonable. The red line might underestimate the depth of the curtailment, but that conservative impact might be fair if the asset required a "warmup" period, as appears to be the case. The black line (normal power level) provided an adequate measure when the power was changing during an event, as was the case for Event 3, Figure 7.49(b). It estimates the normal, unreduced power as an average of the prior and following power levels.



(a) Event 2: June 5, 2014

(b) Event 3: June 9, 2014

(c) Event 4: June 23, 2014

(d) Event 5: June 24, 2014

Figure 7.49. Power Time Series from 3 Hours before Reported Events until 3 Hours after Reported Events. The first, short event in September 2013 was likely a trial event and has been omitted.

The average of calculated impacts from Figure 7.49 is 0.38 ± 0.07 MW. The standard deviation of these differences was 0.13 MW.

The project explored regression models to confirm the estimated power curtailment, but the regression method was rendered inaccurate by the irregular seasonal and diurnal variations in the aggregate chiller power loads. Given that there were very few events to observe, the regression models could not be trusted to calculate impacts in line with those that could be directly observed in for the events in Figure 7.49. The project could not determine how the utility might eventually deploy this asset, but the project confirmed that this asset can defer about 0.38 MW of load for an hour at a time through its responses.

7.10 1.4 MW WSU Diesel Generator

Avista Utilities worked with WSU to develop and communicate DR signals for the control of a 1.4 MW diesel generator at the Grimes Way steam plant on the Pullman, Washington, university campus. The engineering design of this collaboration was described above in Section 7.8. The control of the diesel generator was Tier 3 of the five sets of control signals that were developed jointly by Avista Utilities, WSU, and Spirae. The agreement between the utility and campus laid out mutually acceptable expenses that would be reimbursed by the utility when the generator became activated by the demand responses.

Each engagement was for a 60-minute period. Successive hourly engagements were permitted, but a 6-hour wait was required after any request if the request were denied or if the engagement of the generator was unsuccessful.

The PNWSGD project worked with Avista Utilities to have the DR requests correspond to the advisory signals of the transactive system. A transactive toolkit function was established to anticipate and automate control of the asset based on the transactive system’s incentive signal. The project encouraged the utility to configure the toolkit function to help it determine useful DR events for the diesel generator.

If the utility could control the diesel generator, its generation might displace energy that would otherwise need to be procured by the utility.

The annualized cost for the control of this asset was included in Table 7.18.

7.10.1 Data Concerning the WSU Diesel Generator

The utility submitted to the project the status of each of the four DR signals by which requests, acknowledgements, and confirmations of demand responses were conveyed. Given that the utility had requested 50 or fewer responses from the asset, the project had expected to observe relatively infrequent active requests. That was not the case. The request signal seemed to be more of a system status signal that remained constant for extended periods.

Based on the condition of the Tier 3 asset active signal, the project inferred that control of the diesel generator might have been modified by the DR system no more than twice. The starting times and durations of these two engagements are listed in Table 7.22.

Table 7.22. Generation Events that were Initiated by the Transactive System for the WSU Diesel Generator

Start Time (yyyy-mm-dd hh:mm)	Day of Week	Duration (h:mm)
2014-06-06 10:00	Friday	1:00
2014-07-16 11:15	Wednesday	1:15

Power generation data from the WSU diesel generator is plotted in Figure 7.50. Data was provided for this generator from May 2013 until September 2014. A nonstandard data practice was employed by Avista Utilities, representing all of what the project presumes to be periods of non-generation as not available ("NA"). The project replaced these missing data intervals with zeros. There is some risk that the times that the generator was idle cannot be clearly distinguished from periods of truly unavailable data.

The two short events of Table 7.22 have been marked in Figure 7.50, but there was no generation during the two events. The project cannot explain the discrepancy or the overall lack of successful DR events. The utility was not terribly surprised by this lack of events. Given its portfolio of available resources, the generator was unlikely to often have been an economical resource during the PNWSGD.

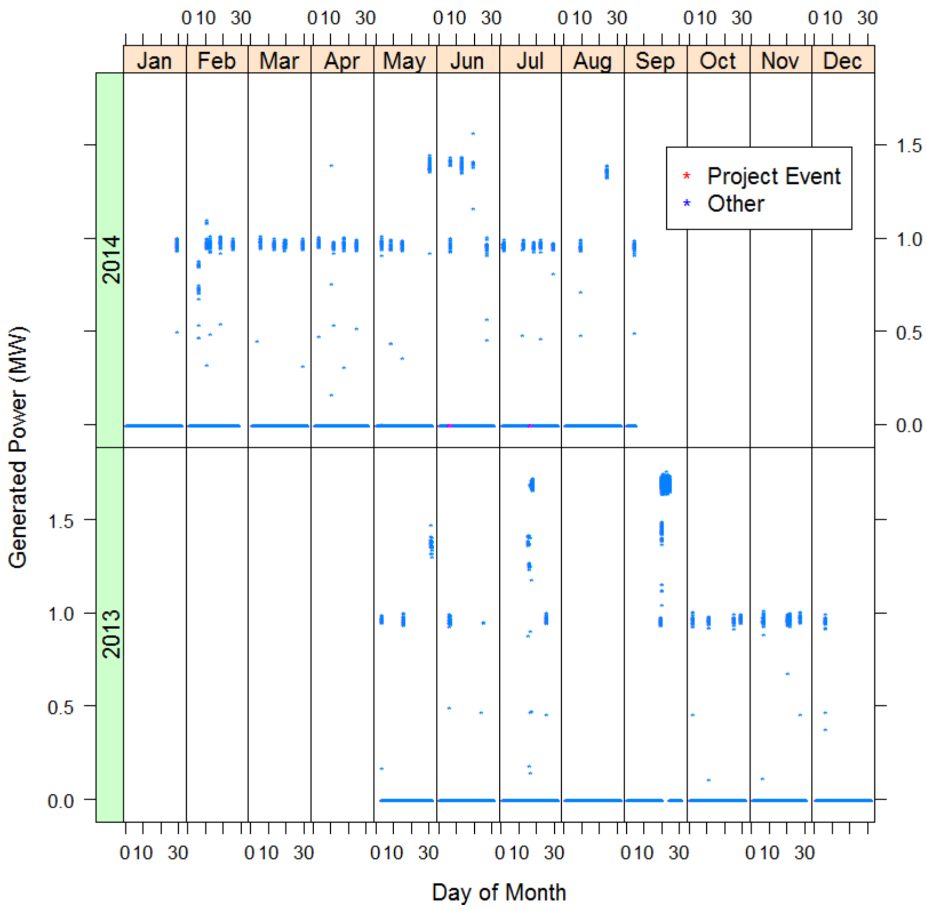


Figure 7.50. Power Generated by the WSU Diesel Generator. Two events were identified, but the generator did not generate during these times.

7.10.2 Analysis of the WSU Diesel Generator Performance

Analysts investigated the distribution of nonzero generated power during the project's 5-minute data intervals. Discrete generation levels were evident in Figure 7.50 and were confirmed in the histogram of Figure 7.51. While the generator had been understood to have 1.4 MW power generation capacity, the generator's power data was as great as 1.76 MW in a 5-minute interval. Four distinct operational power levels are evident, centered at about 1.7, 1.4, and 0.9 MW, with a remaining bin of intervals below 0.8 MW. The vertical red lines in Figure 7.51 separate the four operating modes.

The diesel generator is off, not generating, most of the time, but the overwhelming numbers of intervals having zero power generation were not shown in the distribution of Figure 7.51. The project has assumed that intervals to which "NA" was applied during the data collection period were, in fact, intervals having zero power generation.

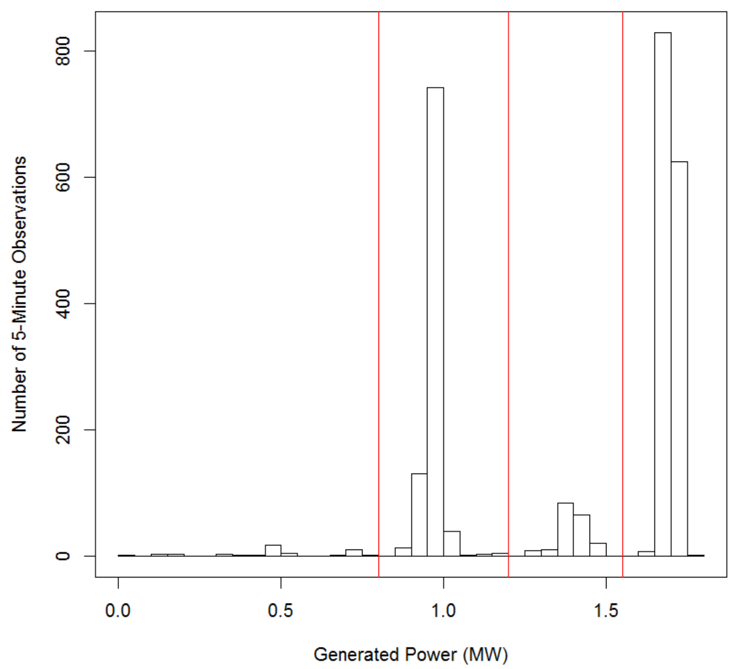


Figure 7.51. Distribution of Nonzero Power Levels that were Generated each Five Minutes by the WSU Diesel Generator. The vertical red lines divide what appear to be four distinct operational modes for this generator.

No significant difference was found between the operation of the diesel generator on weekends and weekdays.

The diesel generator was not energized by the DR signals during the project, but the project reviewed the correlation between generation and the transactive systems' advisory signal for this asset. Figure 7.52 is a side-by-side comparison of the diesel generator's power generation histograms at times that the transactive system had advised no response (i.e., the advisory control signal was zero, left) and had advised increased generation (i.e., the advisory control signal was 127, right). No compelling difference between the histograms is evident.

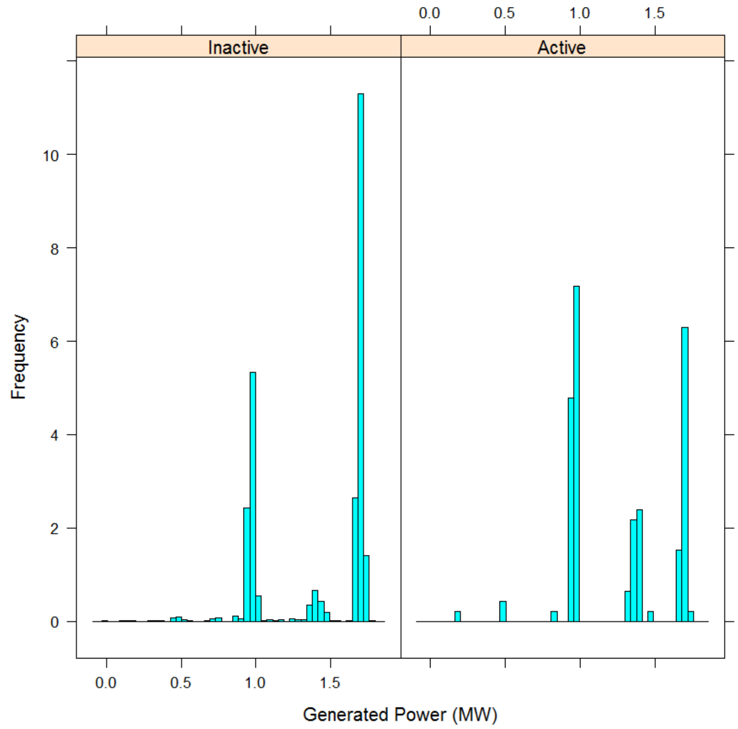


Figure 7.52. Histograms of Nonzero Power Levels Generated by the WSU Diesel Generator when the Transactive System was Actively Requesting Generation (right) and Not (left)

The campus's control strategy is evident from Figure 7.53. This is a contour plot of the average generated power (kW) as a function of month (horizontal axis) and local hour of the day (vertical axis). The hours extend from 0 to 23. The hour 0 is the local hour that begins at midnight, local time. Based on available data, generation peaked in September. Only the September of 2013 is represented in the data. The generator was engaged similarly throughout all hours of the day that month. The generator was used much less other months, but there was some tendency for the campus to engage the diesel generator between 09:00 and 13:00 other months.

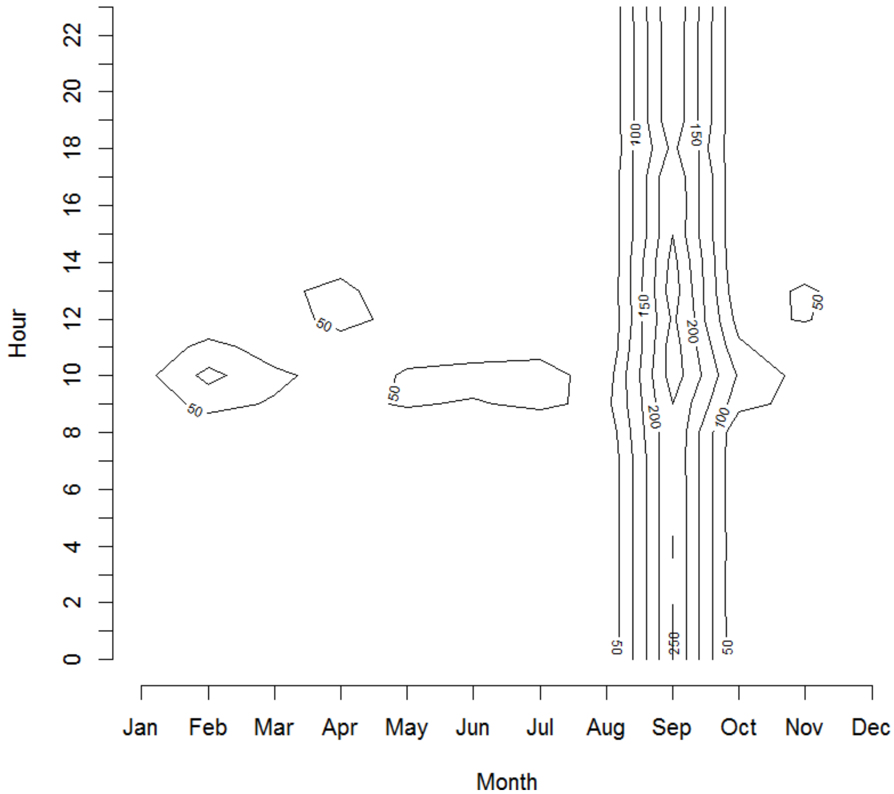


Figure 7.53. Contour Plot of Average Power Generation (kW) of the WSU Diesel Generator as a Function of Calendar Month and Local Hour of Day

In conclusion, the project has little evidence that the WSU diesel generator was ever engaged by the DR mechanisms that were developed jointly by Avista Utilities, the WSU campus, and Spirae. The connection between the asset and the PNWSGD project's transactive system was weak or nonexistent. The project collected operational data concerning the DR system's signals and the generated power for 16 project months, and some operational trends were observed from that data.

If the utility can affect control of the diesel generator, the control of the asset could displace up to 1.75 MW of electrical load, providing that the campus will agree to modify its existing schedules and purposes for dispatching the generator. If 50 hours of operation were successfully procured and timed by the utility, it could displace up to 87.5 MWh of the utility's most expensive energy supply per year. The value is even greater if the generation permits the utility to protect equipment or avoid outages.

7.11 Two 1.1 MW WSU Natural Gas Generators

The project has elected to combine discussion of the performance of the two natural gas generators at the Grimes Way steam plant on the WSU campus. Avista Utilities, WSU, and Spirae designed and implemented a set of DR control signals to request, acknowledge, and confirm generation from these two generators. Details about the DR system are discussed in Section 7.8. The two gas generators were represented by the fourth and fifth of the five asset response tiers of the DR system.

The two gas generators are similar. The DR specification refers to them as generators #2 and #3, but they will be simply described as the first and second WSU natural gas generators in the remainder of this section. The DR agreement stated that responses were to be addressed one hour at a time. Subsequent events were allowed after the successful completion of a prior event, but events were not to be requested within 6 hours after a request was either denied or unsuccessfully initiated.

As was the case for the WSU diesel generator (Section 7.10), the project invited Avista Utilities to make the WSU natural gas generators responsive to the PNWSGD transactive signals. Transactive toolkit functions were established for each of the two generators. The utility was invited to configure the functions so they would automatically advise reasonable events to which the generators could respond.

The annualized costs for the control of this asset were included in Table 7.18.

7.11.1 Data Concerning the Two WSU Natural Gas Generators

The utility submitted all four of the DR system signals with which the demand responses could be requested, acknowledged, and confirmed. As was the case for the WSU diesel generator (Section 7.10), the project had expected relatively few DR requests from the utility to WSU and these assets. Instead, the request signal was mostly static. The full handshake ran to completion only three times for the first WSU natural gas generator, and there were no complete, confirmed DR events for the second. The local starting times, days of week and durations of the three confirmed DR events of the first natural gas generator are listed in Table 7.23.

Table 7.23. Generation Events that were Initiated by the Transactive System for the First WSU Natural Gas Generator

Start Time (yyyy-mm-dd hh:mm)	Day of Week	Duration (h:mm)
2014-01-30 13:40	Thursday	1:00
2014-06-06 10:00	Friday	1:00
2014-07-16 11:15	Wednesday	1:15

Figure 7.54 shows a time series of all power generation data received from Avista Utilities for the first gas generator, and Figure 7.55 is the power generation data for the second. Data was provided for a period from May 2013 to September 2014. The project was supplied “NA” for the data intervals when the generators were idle. This is a poor data practice because it prevents analysts from differentiating periods of no generation from intervals when data was truly unavailable. The generators are believed to have been idle, not generating, most of the time.

Of the three reported events in Figure 7.54, the first gas generator appears to have been generating power during only two of the three events. The generator was likely idle in late January 2014 when the first event occurred. The utility provided some insights why there had been so few events: First, one of the gas generators was out for 3 months due to an emissions problem. The utility was reluctant to use the PNWSGD transactive signal because it was difficult for them to test and validate. They implicitly trusted the AGS signal that they generated themselves. Unfortunately, the AGS was not completed until the month before the PNWSGD ended collecting data. Avista Utilities will always dispatch assets that maintain lowest portfolio cost with best result for customers.

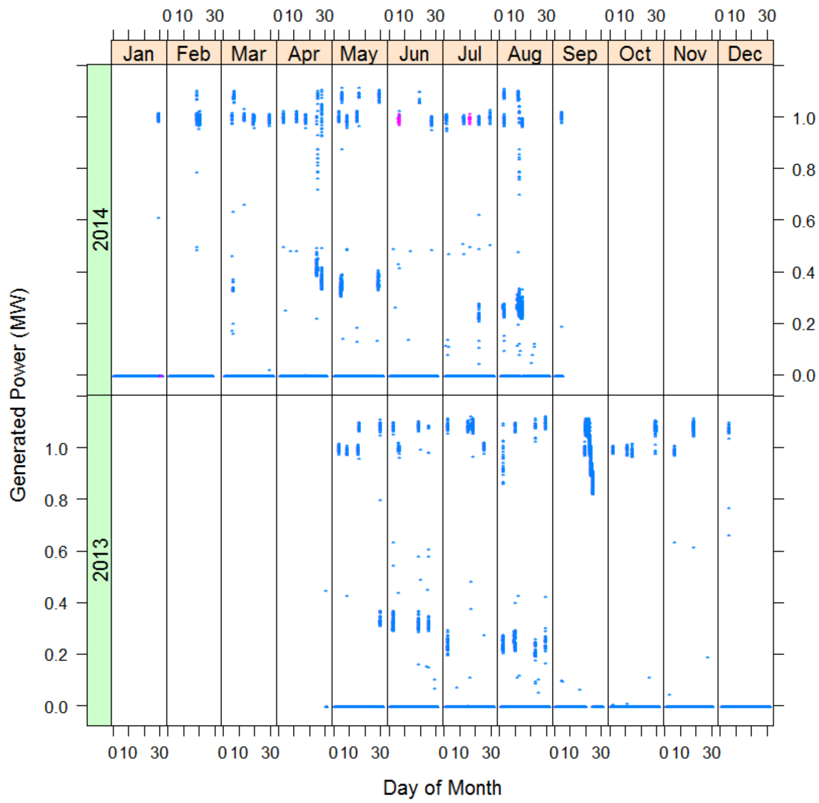


Figure 7.54. Power Generated by the First WSU Natural Gas Generator. Three of the events, marked in red, were reported to have been initiated by the project's transactive system.

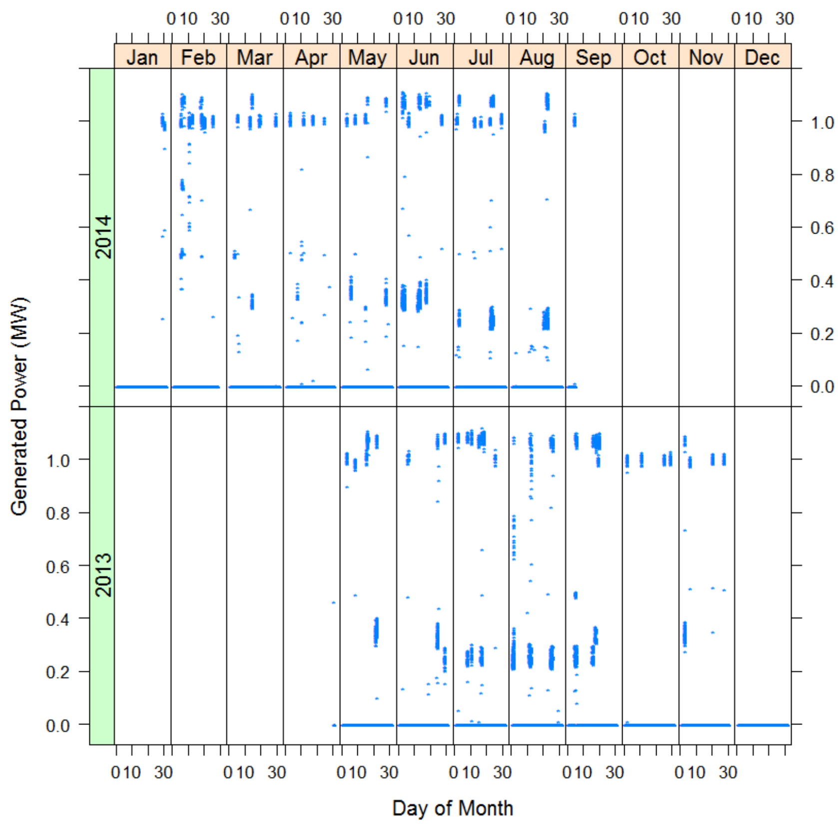
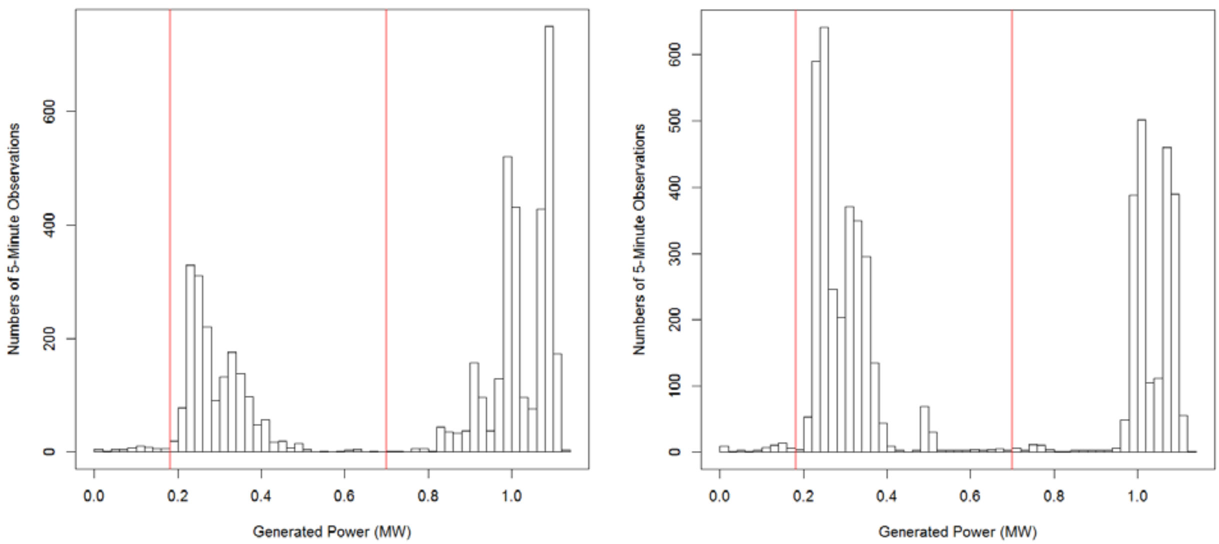


Figure 7.55. Power Generated by the Second WSU Natural Gas Generator. No events were reported to have been initiated by the project's transactive system for this generator.

Transactive event periods were advised by the transactive system for these generators with roughly equal frequency by day of work week. No events were advised during weekends by the transactive system, in accordance with the way the advisory function had been configured. Over 90% of the advised event periods occurred during 2013, and most of the event periods occurred between May and September that year. The periods that transactive responses were being requested did not overlap at all with the three "confirmed" events that were understood to have occurred for the first WSU natural gas generator.

7.11.2 Analysis of the Two WSU Natural Gas Generators

As was the case for the WSU diesel generator (Section 7.10), WSU tended to operate the gas generators at discrete power generation levels. These levels were evident from the time series of Figure 7.55, but they are more evident in the histograms of Figure 7.56. The overwhelming numbers of 5-minute data intervals when the generators were idle have been omitted from Figure 7.56. The remaining intervals reveal that each of the two generators is operated at three power levels—very low and idle, generation between about 0.2 and 0.4 MW, and full power generation of about 1 MW or more. The vertical red lines have been added to the histograms to emphasize the separation of these apparent operational modes.

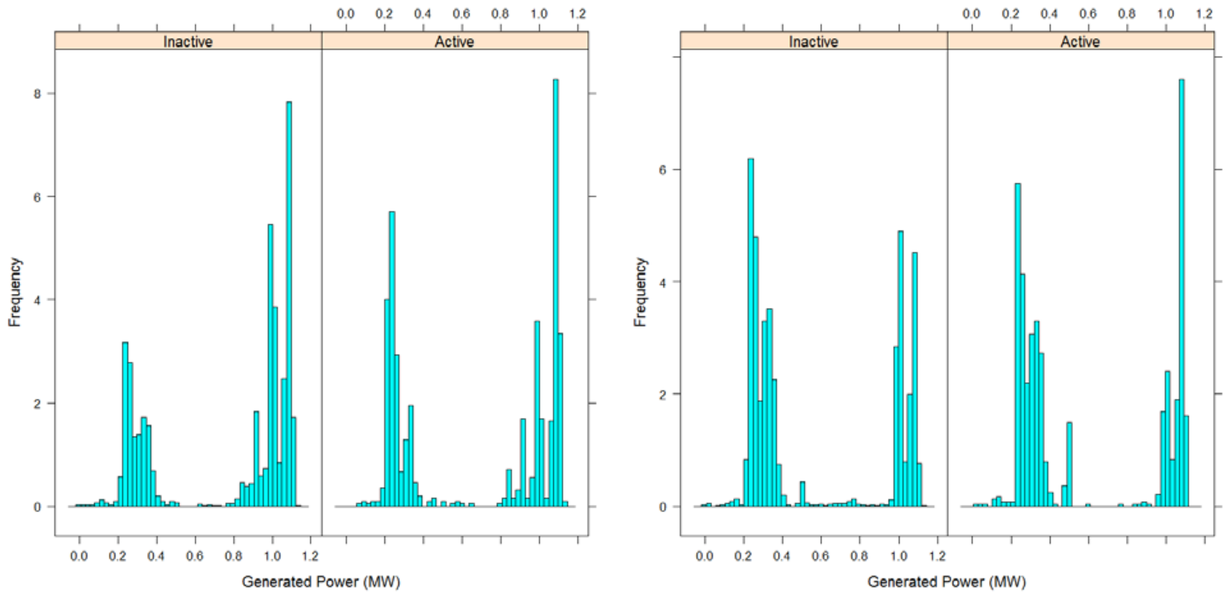


(a) First WSU Natural Gas Generator

(b) Second WSU Natural Gas Generator

Figure 7.56. Distribution of Nonzero Power Levels that were Generated each Five Minutes by the (a) First and (b) Second WSU Natural Gas Generators. The vertical red lines divide what appear to be three distinct operational modes for these generators.

Analysts reviewed the correlation between operation of the WSU natural gas generators and the project's transactive advisory signals that had been generated for these assets. Side-by-side comparisons of histograms are made in Figure 7.57. The first generator is addressed in panel (a) and the second in (b). For each of the two generators, two histograms are shown. The left histogram represents the active power generation at times that the transactive system is advising no response, and the right hand side histograms represent intervals when the transactive system has advised the assets to generate power. The differences between the two paired histograms suggest little or no correlation between the times the generators operated and the advice from the transactive system.



(a) First WSU Natural Gas Generator (b) Second WSU Natural Gas Generator

Figure 7.57. Histograms of Nonzero Powers Generated by the (a) First and (b) Second WSU Gas Generators when the Transactive System was Actively Requesting Generation (right) and Not (left)

The contour plots of Figure 7.58 and Figure 7.59 show that different operational strategies were employed by WSU for the engagement of the two generators. Each shows average power generation by month (horizontal axis) and local hour of the day (vertical axis). The first WSU natural gas generator (Figure 7.58) was apparently left operational for long periods during September 2013. There is almost no difference in the average hourly usage that month. The generation is also engaged during morning and early afternoon hours in early spring months and summer.

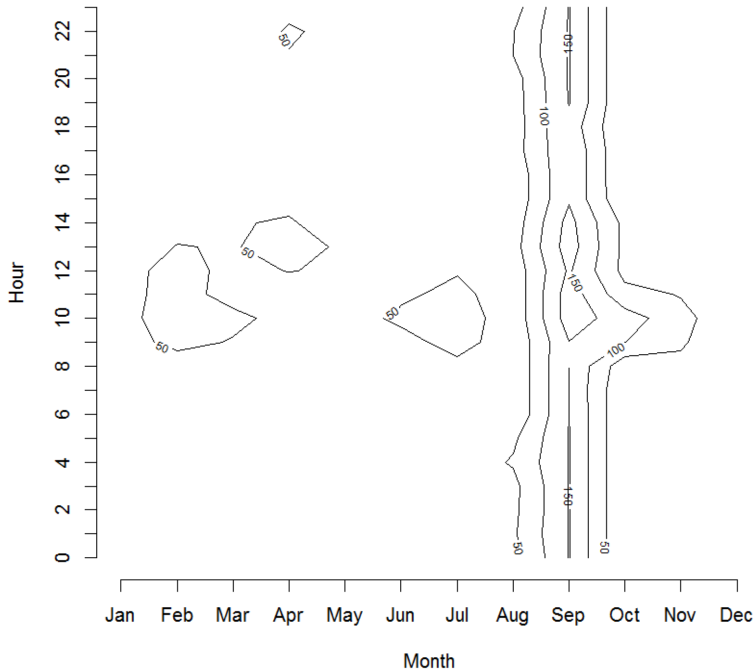


Figure 7.58. Contour Plot of Average Power Generation (kW) of the First WSU Natural Gas Generator as a Function of Calendar Month and Local Hour of Day

Unlike the first WSU natural gas generator, the second (Figure 7.59) was not heavily used in September 2013. It was employed heavily, however, in late winter months of 2014 in the late morning and early afternoon.

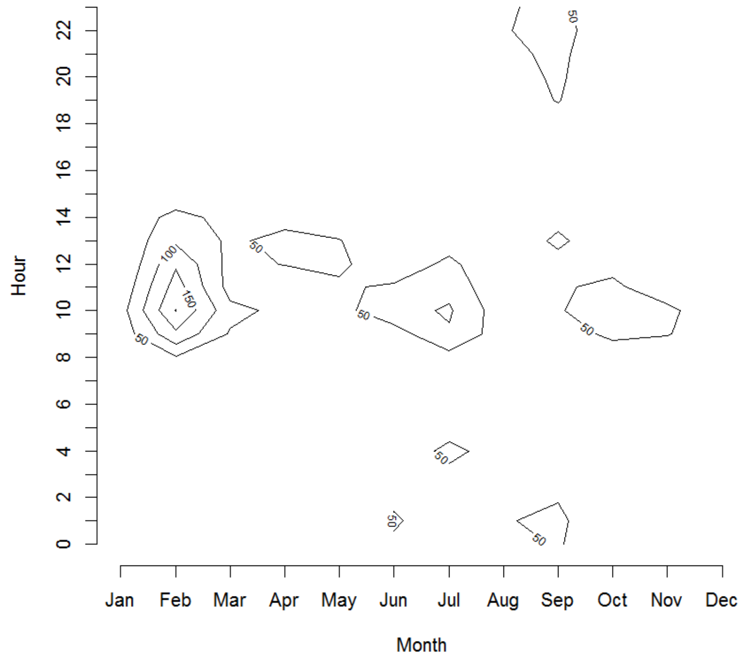


Figure 7.59. Contour Plot of Average Power Generation (kW) of the Second WSU Natural Gas Generator as a Function of Calendar Month and Local Hour of Day

The project's conclusions from this section are very similar to those for the WSU diesel generator (Section 7.10). Based on its data, the project cannot confirm that the natural gas generators were usefully engaged during the project by the DR system that was established by Avista Utilities, WSU, and Spirae. The connection between these generators and the project's transactive system was weak or nonexistent.

The project collected a set of DR system signals and interesting data concerning power generation from the two gas generators. Some existing operational strategies were gleaned from the power generation time series.

If Avista Utilities can modify the operation of these two generators for 50 hours each year, it might displace up to 110 MWh of its most expensive electricity supply each year. This presumes that the university campus has the flexibility to modify the scheduled dispatch of the generators and would accept such DR requests, which was not demonstrated.

7.12 Other Project Activities and Assets

Avista Utilities' participation in the PNWSGD was diverse and extensive. They wish to highlight some additional project activities and project assets that were not already discussed in this chapter.

7.12.1 Distribution Management System

In 1999, Avista initiated a project to complete an accurate field inventory and populate a geographic information system with electric and gas facility models. The inventory process was very thorough and yielded an accurate electric and gas model. This model is referred to as "AFM." Avista also created digital tools for editing and designing against the model as well as the outage management system, which allows distribution dispatch personnel to represent field operation of equipment within the model. Currently, the outage management system does not directly control field devices. This model provides the basis for another key component of the smart grid infrastructure, the DMS.

Avista, as a part of its Smart Grid Investment Grant project, purchased a DMS provided by ACS. The PNWSGD funded implementation of the DMS for Pullman and integration with other back-end systems such AFM, Spirae black box, AMI and DR virtual power plant. The funding for each project, the Smart Grid Investment Grant and PNWSGD, is separated by contract and by product(s). Only software license costs were borne by the PNWSGD project in the form of a purchase agreement and a software license agreement. Software license costs are for products that provide the required functionality as an out-of-the-box solution for the PNWSGD. The PNWSGD project requires a higher level of capability and substantial integration that was not yet available from vendors in final product form. Therefore, PNWSGD functionality was provided contractually via a professional services agreement. The PNWSGD project covered these additional costs, which include integration with the virtual power plant system, the AMI system, smart transformers, smart faulted circuit indicators, and the transactive signal.

The DMS communicates and controls smart devices without human intervention. Dynamic transactive system commands and configuration control for system optimization originated with the DMS either directly or as a result of a request from the Spirae black box and data from the meter data management system that is a part of the AMI.

7.12.2 Fiber Backhaul Communications

Field and customer devices communicated locally via the site's 802.11 wireless network. The 802.11 network, in turn, reached Avista's Spokane headquarters by traversing a fiber backhaul network. That backhaul network path was already complete to the Shawnee substation, which is within seven miles of Pullman as measured by the transmission corridor. Avista partnered with the Port of Whitman to jointly fund the Shawnee-to-Pullman segment parallel to railroad rights-of-way, the total distance of which was up to 15 miles. The project was scoped for as many as four access points along this corridor, possibly located at the three substations—Pullman, South Pullman, and Terre View—as well as at the utility's Pullman service center. Up to 25 additional miles of fiber were required to connect these additional backhaul sites. Routing occurred on existing transmission structures, distribution structures or WSU conduits.

The fiber communication backhaul was a critical component required to provide measurement and status data for the DMS, the AMI back-end systems, and the DR system, and direct communication to customer displays and devices. Communication is a very important enabling technology for smart devices, and it is probably the most critical set of smart grid enabling assets. The fiber backhaul communications network provides for minimal latency and maximum reliability, security, and bandwidth for future growth such as security and mobile workforce applications.

The utility subcontracted with the Port of Whitman for siting, trenching and deployment of the fiber. Avista personnel designed and terminated the fiber.

7.12.3 802.11 a/b/g Wireless Communications

Avista procured and installed an 802.11 a/b/g wireless network provided by Tropos. The wireless network provided coverage for all field assets and AMI meters connected to the feeders sourced out of the Pullman, South Pullman, and Terre View substations.

The 802.11 wireless type is used heavily by business and consumers and is considered a mature technology. Approximately 90 wireless access points were installed on utility poles, some of which were colocated with field devices. All smart switches, fault circuit indicators, smart transformers, and capacitor bank controls communicate via this wireless network with the DMS and /or RTUs at Avista central headquarters in Spokane, Washington.

The Itron AMI meters used a bridge device to transition from the 900 MHz Open Way radio frequency to the 802.11 wireless network.

7.12.4 Avista-WSU Curriculum Project

It is critical to Avista Utilities that there are talented, educated engineers and technicians available to hire. Avista worked closely with WSU to modernize power electrical engineering laboratory courses in Pullman during the five-year program. These improvements were thoroughly described in an unpublished report from the university to the utility.[1] The highlights of the report discuss new laboratory classes “Renewable Energy” (EE492) and “Power System Protection” (EE494). Additionally, a new professional science master’s degree program is offered, and online teaching classroom capabilities have been improved.

7.13 Conclusions and Lessons Learned

Avista greatly modernized the Pullman site distribution system and considers its participation in the PNWSGD to have been very successful. During the project, the utility implemented IVVC on many of the 13 feeders. The project was able to confirm that these efforts would indeed conserve about 2% of the electrical load in Pullman. Power factors were significantly improved on at least 9 of the 13 feeders. Avista values this conservation at over $0.5 million per year, based solely on the value of avoided energy purchases. The utility initially encountered delays as it calibrated the system’s sources of end-of-line voltages, but they were eventually able to measure customer voltage within the 0.5% accuracy that was needed by the voltage optimization system.

A couple of miles of reconductoring was necessary to reduce system losses and maintain the flexibility needed for optimal circuit topology. The utility estimated that 29.6 MWh will be conserved each year due to the improved conductors.

[1] A Bose, CC Liu, R Olsen, V Venkatasubramanian, A Srivastava, A Mehrizi, B Carper, R Zamora, J Opheim, and J Yates. 2014. “Final Report: Avista-WSU Curriculum Project.” Washington State University, Pullman, Washington, September 25, 2014 (Unpublished).

The utility replaced its oldest, least efficient distribution transformers with about 400 smart transformers. Regrettably, the transformers were not monitored in a way that would have permitted the project to confirm such energy savings from improved energy efficiency. The smart transformers provided new voltage and status metering points. The newly available information now facilitates transformer health assessment, finding of energy loss and theft, and operation of the distribution system closer to acceptable voltage limits.

About 70 smart, communicating ecobee thermostats were supplied to a group of Pullman residential customers. Recruitment of these participants was challenging. The project was able to tentatively confirm a very, very small conservation during the project's transactive events. Questions remain about when and whether these events were, in fact, communicated to the thermostats and Avista conducted additional DR events that were unknown to the project. Regardless, the utility learned much about recruitment and customer acceptance of this type of program. Those customers who had received thermostats were generally satisfied with their program experiences.

Avista investigated how its customers would use energy web portals and whether they would conserve energy given transparent information about their own energy consumption habits. Small, but statistically insignificant, energy conservation was found for customers who were provided access to a customized energy web portal. This finding was consistent with that in the contracted Freeman, Sullivan, and Co. report. Regardless, by Avista Utilities' assessment, the modern features of AMI were attributed by them with saving $235 thousand per year in Pullman through a combination of remote meter reading, improved customer services, and reduced service site visits. By the utility's estimation, 2,714 truck rolls per year are being avoided with the AMI's ability to confirm power status and remotely open and close accounts.

The utility installed an FDIR system to more quickly respond to outages and reduce the duration of outages that its customers experience. The project observed that these improvements were not evident in the reliability metrics SAIFI, SAIDI, or CAIDI. The utility's conclusion may be more optimistic based on automated reports of avoided customer outages from its upgraded DMS. By the utility's estimation, the FDIR system reduces 12,000 to 16,000 customer outage hours per year, valued at $10 per customer outage hour. The more efficient identification of and response to outages also reduces vehicle miles and emissions.

The utility worked closely with WSU to make a set of campus loads responsive to DR requests from the utility. The assets included reduction of building air circulation fan load, reduction of cooling-loop pump load, and control of three onsite diesel and gas generators. The project confirmed that about 240 kW was conserved by the curtailments of air circulation fans, and about 380 kW was conserved through control of the chiller loops. The project was able to find no evidence that the times that the generators were operated had been influenced by project signals, but if Avista can procure control of these assets, it might procure up to 3.7 MW of distributed generation.

Overall, the utility estimated that its activities under the PNWSGD project reduced greenhouse gas emissions by 2,367 tons of CO_2.

While Avista Utilities encountered immaturity among the smart grid assets that it deployed during the PNWSGD, these challenges were mostly overcome, and the Pullman, Washington, distribution system has been significantly modernized by its participation in the PNWSGD project.