13.0 City of Milton-Freewater Site Tests

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The City of Milton-Freewater is a municipality in northeast Oregon that serves about 7,000 residents. It is proud to be one of the oldest municipal electric utilities in Oregon and has power rates among the lowest in the Pacific Northwest. The city's electric utility is a pioneer in energy conservation and demand-response (DR) programs. For example, its Radio Energy Management System direct DR program began in 1986 and has helped the city keep its electric rates low (City of Milton-Freewater 2014).

The City of Milton-Freewater offered its entire municipality to be used as a Pacific Northwest Smart Grid Demonstration (PNWSGD) project site. The site's electric circuit consists of three substations—Freewater #1, Freewater #2, and Milton—and altogether 13 feeders that are supplied by these three substations. The distribution circuit is radial during normal operations, but the city can move electrical load from any feeder to be supplied by an alternative feeder during maintenance outages and after unplanned outages. The city helped the project track the times when their distribution circuit was in an alternative configuration so that analysis could focus on normal operation. The city gets its electricity from the Bonneville Power Administration (BPA).

Within PNWSGD transactive coordination system, the City of Milton-Freewater is Site 9, which was included within Transmission Zone 11 (NE Oregon). Refer to the transactive coordination system topology (Appendix B). The transactive signals represented the cost and quantity of electricity at the BPA transformer that supplies the entire city. (Some background information about the PNWSGD transactive system was given in Chapter 2.) The site's transactive feedback signal predicted the electric power received at this BPA transformer, and the transactive incentive signal (TIS) predicted the unit cost of the electric energy received from BPA at this point. This virtual point of interconnection is at the top of the Milton-Freewater layout diagram, Figure 13.1.

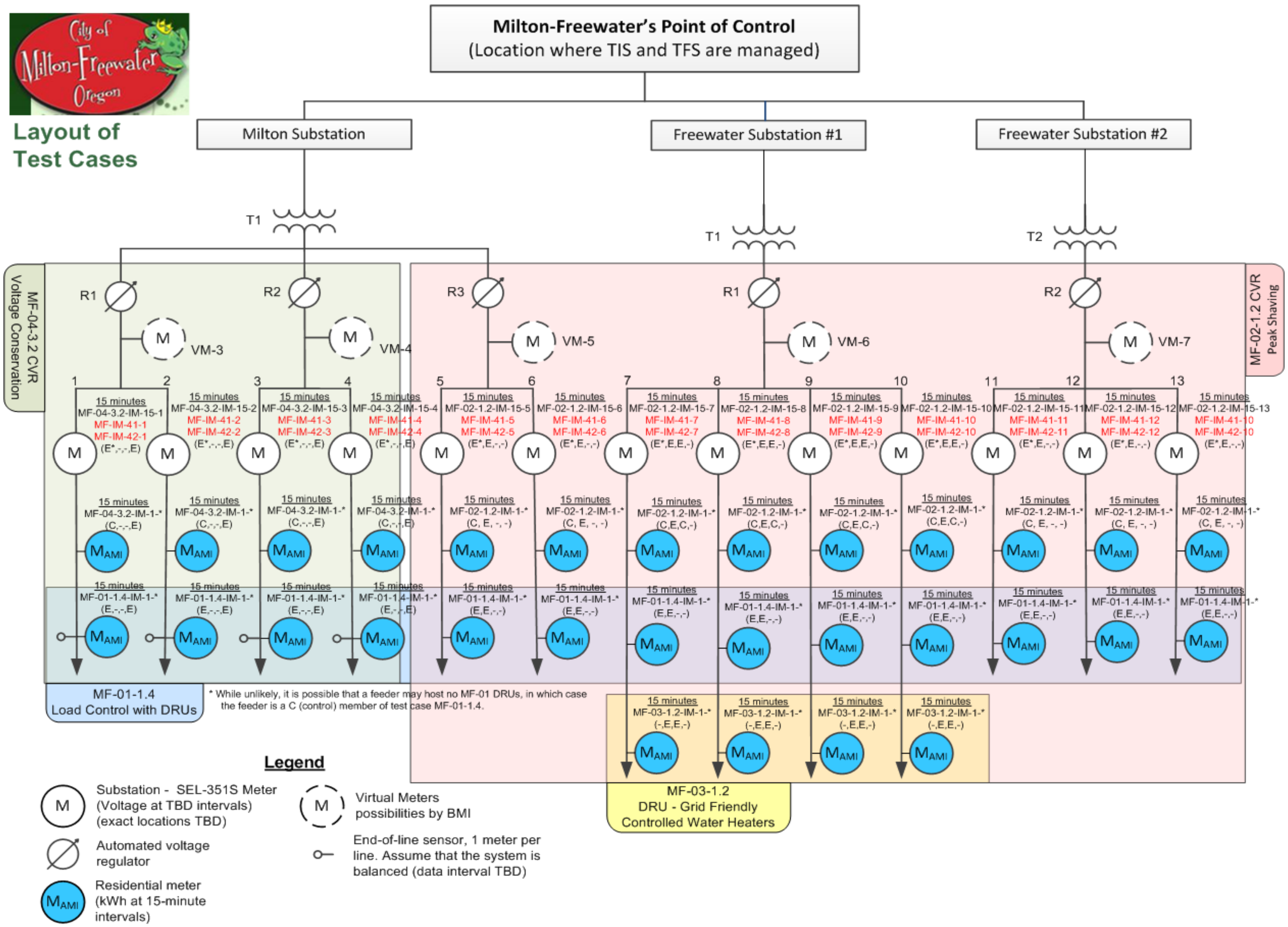


Figure 13.1. Layout of Milton-Freewater Test Populations in Relation to One Another and the City's Distribution Feeders. Premises groups are positioned to show which feeders they are supplied by, not their positions on the feeders.

The city accepted an instantiation of the IBM iCS (Internet-scale Control System) software that initialized basic system functionality and communication within the PNWSGD transactive system. The acceptance of an IBM iCS reference implementation somewhat hastened the establishment of their transactive system site. Additionally, QualtityLogic used a test harness that it had developed to enforce the conformance of the site to the project's reference implementation and its documentation. CVO Electrical Systems, LLC, helped the city establish and configure site functionality and communication.

The magnitude of the site's incentive signal was usually identical to the modeled cost of energy supplied by Transmission Zone 11 in the transactive system. However, the site also implemented the project's BPA demand-charge toolkit function, which (1) monitored and predicted peak load, (2) estimated the cost impact that was to be incurred by a newly predicted system peak, and (3) added this cost impact to the site's TIS during periods of peak demand. The revised incentive signal then caused site assets to curtail load when the incentive signal reflected the additional costs that were being incurred to supply peak demand. The site thereby could reduce its peak-demand costs for the month. At this site, the formula for monetizing peak-demand impacts was based on BPA customer demand rates (Appendix C).

Advanced metering was a component of several of the city's asset systems. The city procured and installed 3600 Landis+Gyr single-phase electric meters, 610 Elster three-phase electric meters, and 2,400 Badger Orion water meter transmitters within its Milton-Freewater service area boundary. All these meters use Aclara's Two-Way Automatic Communication Systems (TWACS®) over power-line carrier and were therefore compatible with the existing systems that the city had previously installed. Some new substation TWACS communication equipment had to be purchased and installed to support the new premises metering.

The 2,400 Badger Orion water meter transmitters were installed at locations where the city was upgrading premises metering. Because the city supplies its residents both electricity and water, the same advanced meter infrastructure could be used to read both electricity and water usage. Efficiency was gained because these transmitters communicate to the premises' electrical meters.

The city installed Aclara disconnect-switch interbase collars (Aclara 2011) on a sample of its single-phase premises meters. The collars provide a convenient means to remotely disconnect and reconnect customers, which may be useful for rental properties, vicious dogs, inaccessible meters, habitually delinquent customers, and in prepaid utility programs. Two hundred eighty-six of these were initially purchased by the city for the project. Because of their success, even more were purchased and installed during the project, and the city plans to install still more of these disconnect collars in the future.

The city installed the following four asset systems in the PNWSGD. The first three were responsive to the PNWSGD transactive coordination system.

- Demand-response units (DRUs) on water heaters and space conditioning equipment (Section 13.2)
- Dynamic distribution voltage management (Section 13.3)
- Voltage-responsive, grid-friendly DRU (Section 13.4)
- (Static) conservation voltage reduction (CVR) (Section 13.5).

The primary purpose of the first three asset systems was to respond to infrequent events. From the NorthWest power system's perspective, asset's system responses mitigate regional issues of those entities that have generated and supplied the power that was used by the city. From the city's perspective, response of system assets reduces the high costs of serving monthly peak demand. As shown in Figure 13.2, the City of Milton-Freewater residential demand peaks in the morning during winters, has similar morning and afternoon peaks during spring and fall, and has a single afternoon peak during summer. This figure represents average weekday power per premises for members of the DRU test group at Milton-Freewater (Section 13.2). Premises consume much more power during winter than during the other seasons.

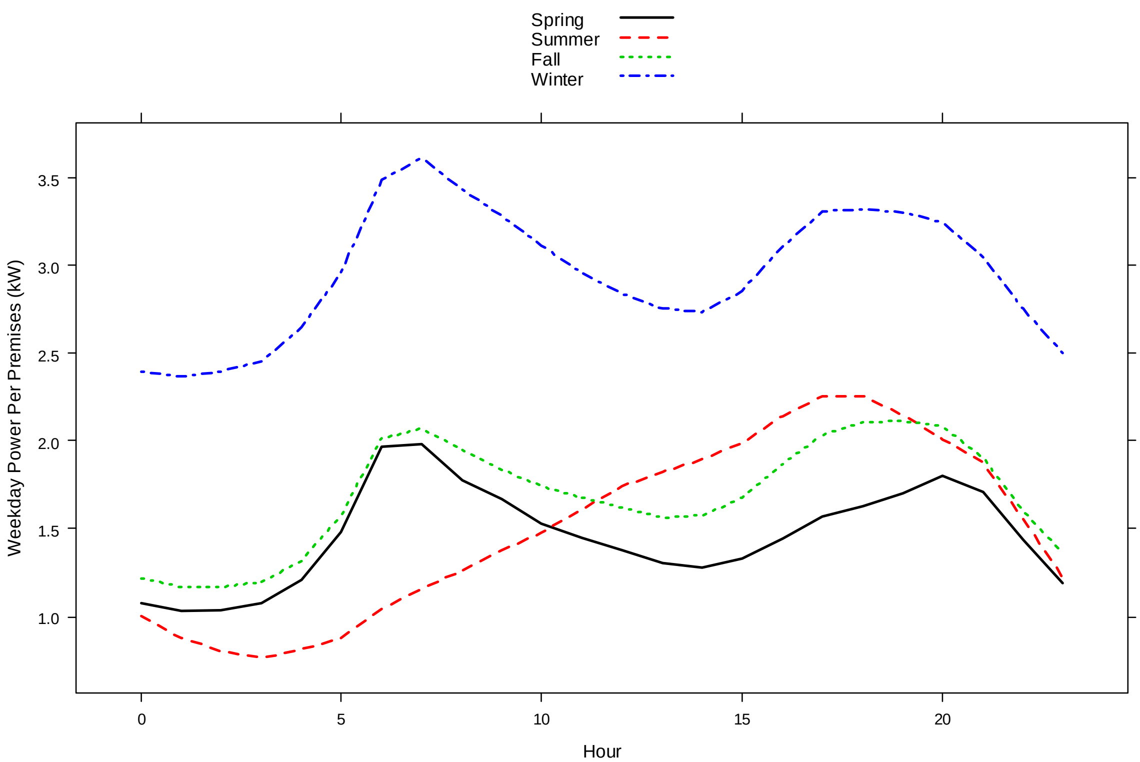


Figure 13.2. Seasonal, Per-Premises Load Shapes for the Homes among the Milton-Freewater DRU Test Groups

The data collection layer of the iCS reference model automatically submitted data to the transactive system, including system management commands, system state, predicted weather variables, predicted total site electric load, the site's versions of the TIS and transactive feedback signal, and the advisory control signals and predicted impacts (changes in load) that were exchanged with each of the three responsive asset systems.

Other data (i.e., non-transactive data) were submitted by the city to the PNWSGD secure file transfer protocol site. These data included 15-minute-interval distribution meter data, premises data, and the actual engagement statuses of the asset systems. Sparse data was sometimes submitted directly from the city to data collection team members at Battelle.

The analysis of the two asset systems that managed distribution voltage anticipated an impact at the level of the distribution feeders. Figure 13.3 summarizes the three groupings of summed feeder power that were useful in analyzing distribution-level impacts. The groupings of feeders correspond to the groupings that are shown in the layout diagram, Figure 13.1. Feeders 1–4 are where the static version of CVR was exercised (see Section 13.5), and the dynamic version of voltage management (see Section 13.3) affected Feeders 5–13. The sum power on Feeders 7–10 was useful as the project attempted to isolate the impacts of voltage-responsive water heaters on these feeders (see Section 13.4) from the more passive impacts of voltage management on the larger set of Feeders 5–13.

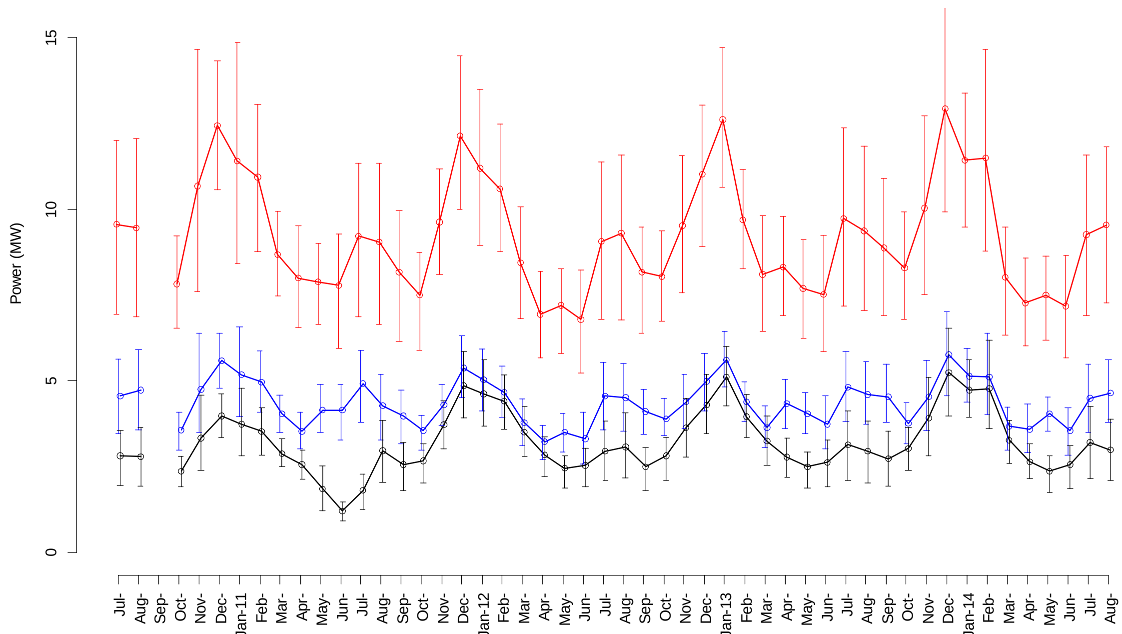


Figure 13.3. Averaged Monthly Power for Summed Feeders 1–4 (black), 5–13 (red), and 7–10 (blue). The bars represent standard deviations of the monthly data sets.

Groupings of residential meters were used to analyze impacts of the various Milton-Freewater asset systems at the premises level. The premises power was averaged for the members of each of these groups at a data interval of 15 minutes. The most important premises groupings are shown in Figure 13.1. More detail about the test and baseline groupings will be provided in the detailed discussion of each asset system.

13.1 Transactive Demand-Charges Function

The City of Milton-Freewater has long used DR programs to reduce its exposure to demand charges. Should the demand exceed a threshold value, BPA charges the city an elevated demand rate that is based on the difference between its total demand during its peak, heavy-load hour each month and its average load during all the month’s heavy-load hours. So the challenge is to observe demand, anticipate peak hours, and curtail load during these hours. During 2013, the city exceeded its demand threshold at least once during nine of the 12 calendar months.

The city's staff, after years of experience, possesses keen abilities to accurately predict these peak days and hours without automation. An automated system must do at least as well as these experienced people if it is to be adopted.

Working with the PNWSGD, the city allowed its incentive signal to be affected by an automated BPA demand-charges function. This function monitored the predicted total demand at Milton-Freewater and increased the incentive signal magnitude as new monthly peak demands occurred. Had this function worked as intended, the DRUs and other of the city's asset systems would have become automatically engaged by the elevated incentive signal. Unfortunately, the demand-charges function did not accurately predict the actual system demand magnitude and the timing of peak hours. The load that was predicted by the transactive system and actual SCADA (supervisory control and data acquisition) measurements were not tightly coupled during the project, which coupling is necessary if predicted load is to be corrected and improved over time. Therefore, while the project's approach to automation of responses during utility peak hours may be valid, the project's automation was not especially effective at engaging the DRUs at the correct times.

The transactive demand-charges function initially tried to reproduce the entire calculation used by BPA to determine peak-demand charges for its customers (BPA 2011, Section 5.3). The BPA charges are presently determined after the fact at the end of each calendar month. Some, but not all, the calculation's inputs can be known at the beginning of each month. This method proved too cumbersome to apply well, and there was resistance from utility sites to provide all the inputs that were needed to predict a reasonable demand threshold power level. In Milton-Freewater's case, the demand-charges function never achieved a workable configuration. The function output predicted that demand charges were being incurred only for a few minutes in May 2013. What proved more useful was for knowledgeable utility staff to predict a reasonable demand threshold based on their intuition and experience. The alternative approach was simple and more successful.

The demand-charges function also failed to reasonably predict a useful time interval around the times at which new demand thresholds were likely to become established. Therefore, the function made the incentive signal spiky, and it was not interpreted well by the assets that could have responded to the incentive signal. Perhaps statistical likelihood would be useful to meaningfully disincentivize load during peak hours.

Fortunately, the city retained the ability to manually engage or disengage this system, as needed, even if doing so was contrary to the advice from the transactive system.

13.2 Load Control with DRUs

The City of Milton-Freewater purchased 800 Aclara DRUs (Aclara 2012) and installed them at residences and a few commercial buildings throughout their distribution circuits. These devices control either conventional 240 volts alternating current electric tank water heaters or space conditioning units. When they receive a command to curtail load via the TWACS power-line carrier communication system, they open a switch to their electrical load and curtail or defer its energy consumption. While advanced premises metering might not be required at locations that host these DR units, premises metering is useful to confirm the impacts of load curtailments.

The main purpose for which the city installed the DRUs was to reduce demand charges that it incurs in its monthly bill from the BPA. The Aclara DRU system provides some software assistance and automation based on the city's demand metering, and this system engages subpopulations of the entire DRU population to keep system load under a desired threshold. The events initiated independently by Milton-Freewater staff (i.e., ones that were not advised by the transactive system) were found to include the control of subpopulations and feedback—features provided by vendor software. Automated responses to the project's TISs, however, did not include these features and simply controlled the entire block of DRUs. Regrettably, a vendor software error was found to have prevented many of the project's transactive system events from having been acted upon prior to about July 2014.

The city allowed customers who possessed DRUs to be subjected to no more than five curtailment events in any calendar month. The city prefers that the curtailment events not persist more than four hours, beyond which duration its customers become inconvenienced.

The estimated annualized DRU system costs are shown in Table 13.1. These cost estimates are for the entire system that would be needed to operate the DRUs. The city provided input to the project concerning how it perceives these costs. A major cost component is the 800 DRUs. The system also includes a fraction of the advanced premises meters that are colocated with the DRUs and a fraction of the cost of automating the system and connecting it to the transactive system. Lesser component costs included installation labor, operations and maintenance, and requisite software. These lesser costs were included with the costs of the listed major equipment. These costs have been annualized in the sense that we assume all equipment will be perpetually maintained and replaced after its expected lifetime.

Table 13.1. Annualized Costs of the Milton-Freewater System of 800 DRUs

	Component Allocation (%)	Annualized Component Cost ($K)	Allocated Annual Component Cost ($K)
AMI Meter System			154.7
• Residential and Commercial	33	270.3	90.0
• Water	100	64.7	64.7
DRUs	100	100.5	100.5
Transactive Node	33	9.8	3.2
Programming to Link SCADA	100	1.9	1.9
Total Annualized Asset Cost			**$260.4K**

AMI = advanced meter infrastructure

13.2.1 Characterization of DRU System Responses

The DRUs were curtailed 200 times from August 2012 through August 2014, and these event periods have been summarized in Figure 13.4. In this figure, the vertical bars represent the durations of the events (vertical distance) on the days that the events occurred (horizontal axis).

The DR vendor provided a feature that engaged and released the DRU curtailments based on feedback of total city demand. Series of multiple, short-lived events were combined by the project during analysis and were treated like a single event if they were separated by less than 1 hour of disengagement.

The multiple short events might pose a problem for analysis. First, unless the transition times are very accurate, the impacts may be applied to the wrong periods. Even if the event times are accurate, the transition times did not always align with the 15-minute measurement intervals that were employed by Milton-Freewater. Therefore, the impacts will tend to be understated.

Additionally, the project confirmed that the remaining curtailment events that did not employ the vendor feature described above were often ignored prior to summer 2014, when a software error was found and corrected by the DR vendor. This is unfortunate and will cause the project to further understate the impacts from the DRU curtailments.

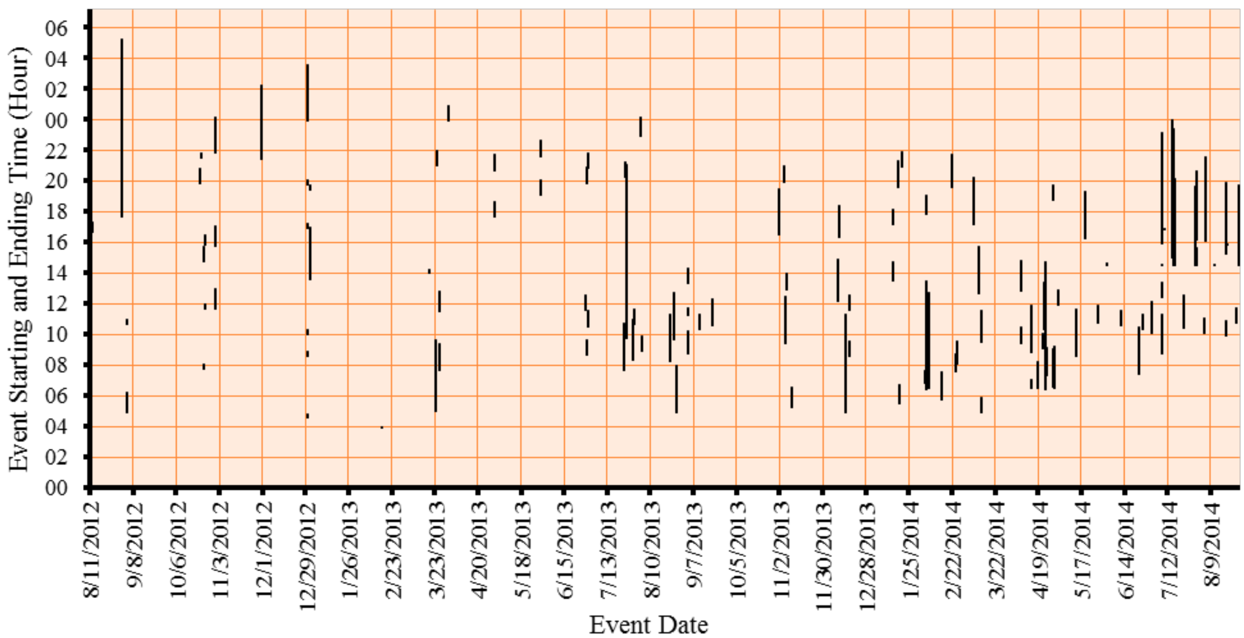


Figure 13.4. Days and Durations of Milton-Freewater DRU System Events during the Term of the PNWSGD Project

DRU curtailment periods happened to occur during the utility's actual monthly peak hours only one month during the project. The DRU curtailment times were found to have occurred 84% of the time during BPA heavy-load hours. The DRU curtailment times were found to have occurred 84% of the time during BPA heavy-load hours.

The project had requested but not insisted that DRU events be conducted at the times advised by the project's transactive system. In fact, the DRUs were found to have been curtailed for 71% of the time periods that had been advised by the transactive system. Sixty-eight percent of the time that DRU events were conducted, the events were also being advised by the transactive system. None of the advised transactive event periods were determined to have actually coincided with one of the city's monthly peak hours.

Figure 13.5 summarizes the months when the DRU curtailment events that were shown in Figure 13.4 occurred. Events were not counted if they followed the preceding curtailment by less than 1 hour. The fraction of August curtailments is overstated because there were three Augusts during the project, while there were only two instances of the other 11 months. The curtailments were fairly evenly distributed by month, but the system might be employed more frequently during winter and summer peaks.

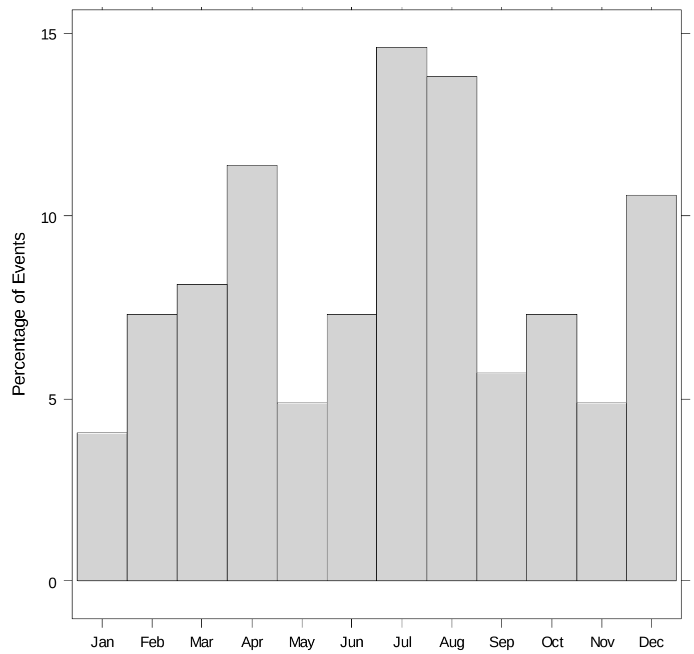


Figure 13.5. Months in which DRU Events were Called by Milton-Freewater. This histogram excludes multiple consecutive events that were separated by less than 1 hour.

Figure 13.6 summarizes the hours (local Pacific Time) that the DRU events started. The transactive system might have advised curtailment of the DRUs during any hour based on regional transmission and generation conditions, but the city benefited most directly from curtailments that coincide with the city's morning and afternoon heavy-load and peak hours.

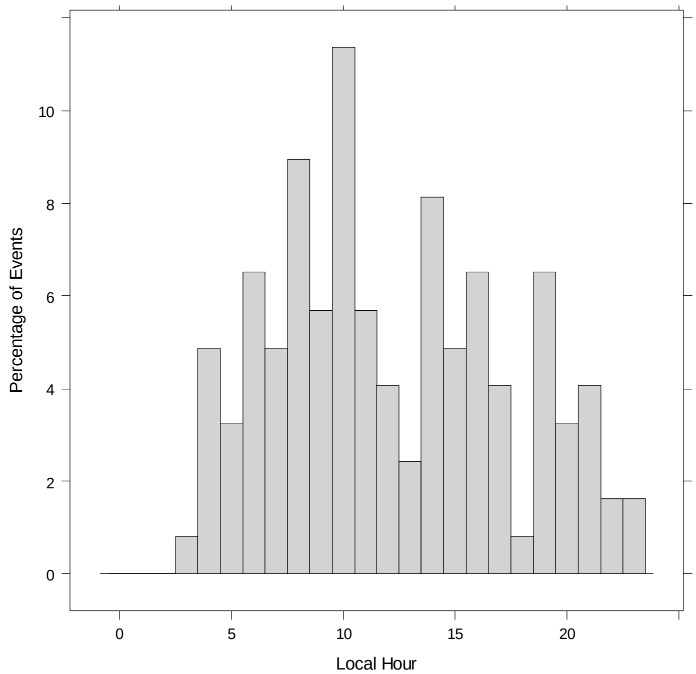


Figure 13.6. Local Starting Hours (Pacific Time) when DRU Events were Called by Milton-Freewater. This histogram excludes consecutive events that were separated by less than 1 hour.

Review of premises power data from during the curtailment events indicates that many events from late in the project exhibit the expected power reduction during events and the even-more-evident rebound afterward. The effect of the rebound is often more pronounced than the reduction and should be a reliable marker in time. However, the data from some curtailments appear to be shifted with respect to the event indicators that were given to the project by Milton-Freewater. Figure 13.7 is one such instance when it appears, based on the rebound impact marker, that the event markers are shifted 1 hour earlier than the actual event. Figure 13.8 suggests that the event might have been terminated earlier than was indicated. If the event indicators are in error, then the event and rebound impacts will be somewhat miscalculated.

It has already been stated that, because of a vendor software error, many curtailments from early in the project period might have never been acted upon. Neither curtailment reductions nor rebound increases were evident by inspection in early (i.e., prior to July 2014) DRU event data.

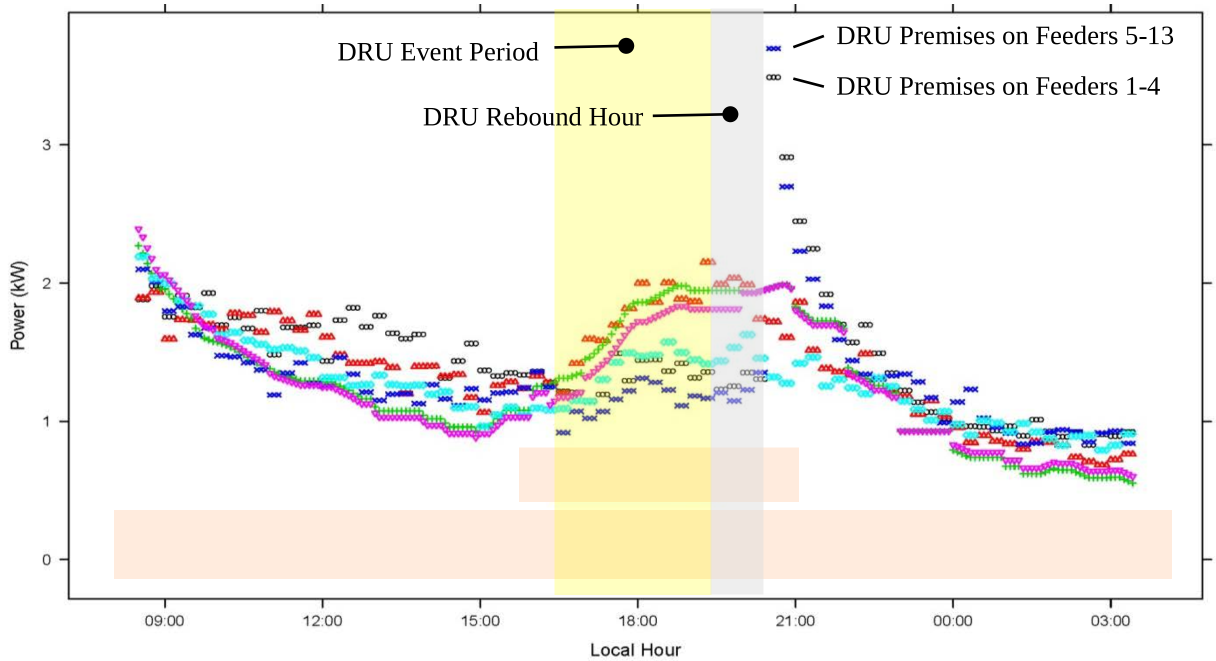


Figure 13.7. DRU Curtailment Event from November 1, 2013. The average DRU premises powers on Feeders 5–13 (blue "x"s) and on Feeders 1–4 (black circles) exhibit rebound effects, but they occur more than 1 hour after the event period (yellow shading) was reported to have ended and after the rebound hour (gray shading). The other time series are from various Milton-Freewater premises that did not have DRUs.

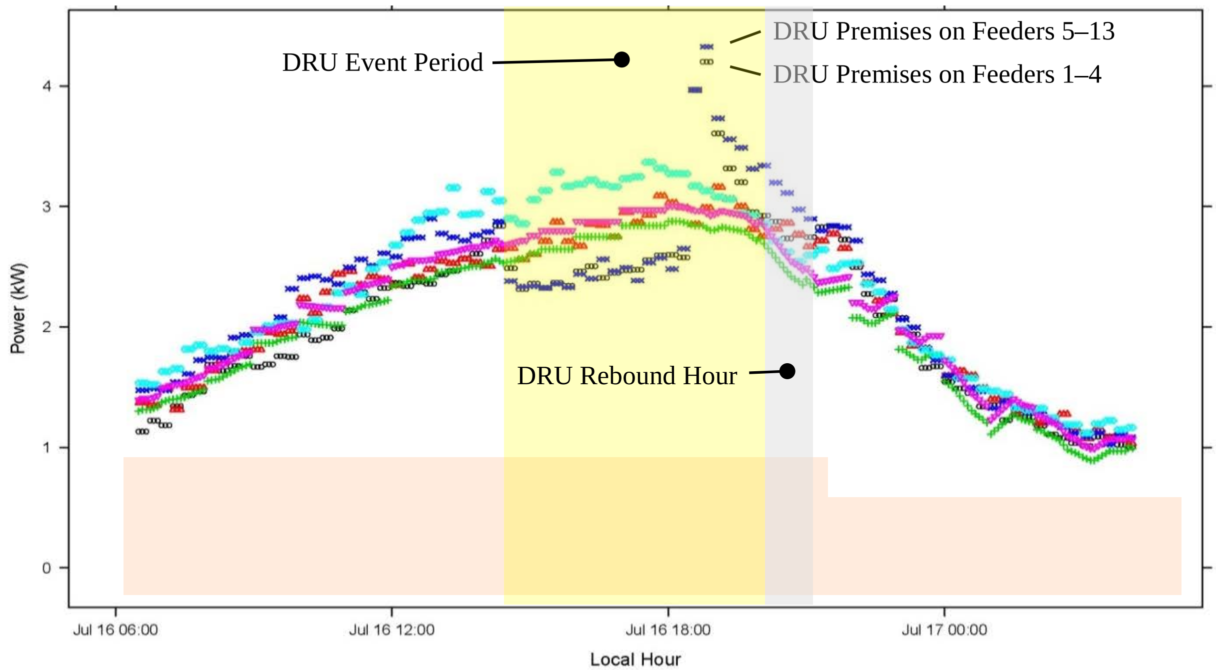


Figure 13.8. DRU Curtailment Event from July 16, 2014. In this example, the rebound effect on average premises powers from premises on Feeders 5–13 (blue “x”s) and Feeders 1–4 (black circles) occurred prior to the reported conclusion of the event period (yellow shading) and rebound hour (gray shading). The other time series are from various Milton-Freewater premises that did not have DRUs.

Figure 13.9 shows a DRU curtailment event from July 15, 2014 that was managed by vendor software using feedback from the city’s entire electric power load. The event period is shown by yellow shading and the rebound hour is shown by gray shading. The vendor’s software engaged and disengaged the DRUs multiple times during the event period, but the project reported and analyzed this period as a single event. Some degree of reduction and increase seems to accompany the curtailment and rebound periods. The rebound peaks for these events are not as great as for events that were simply turned on and then off. The project has some concerns whether the data and event indicators will accurately align for such active management with rapid transitions from the DRUs being engaged and not. If the alignment of DRU actions and event indicators is inaccurate, the impacts from curtailment and rebound will be miscalculated once again.

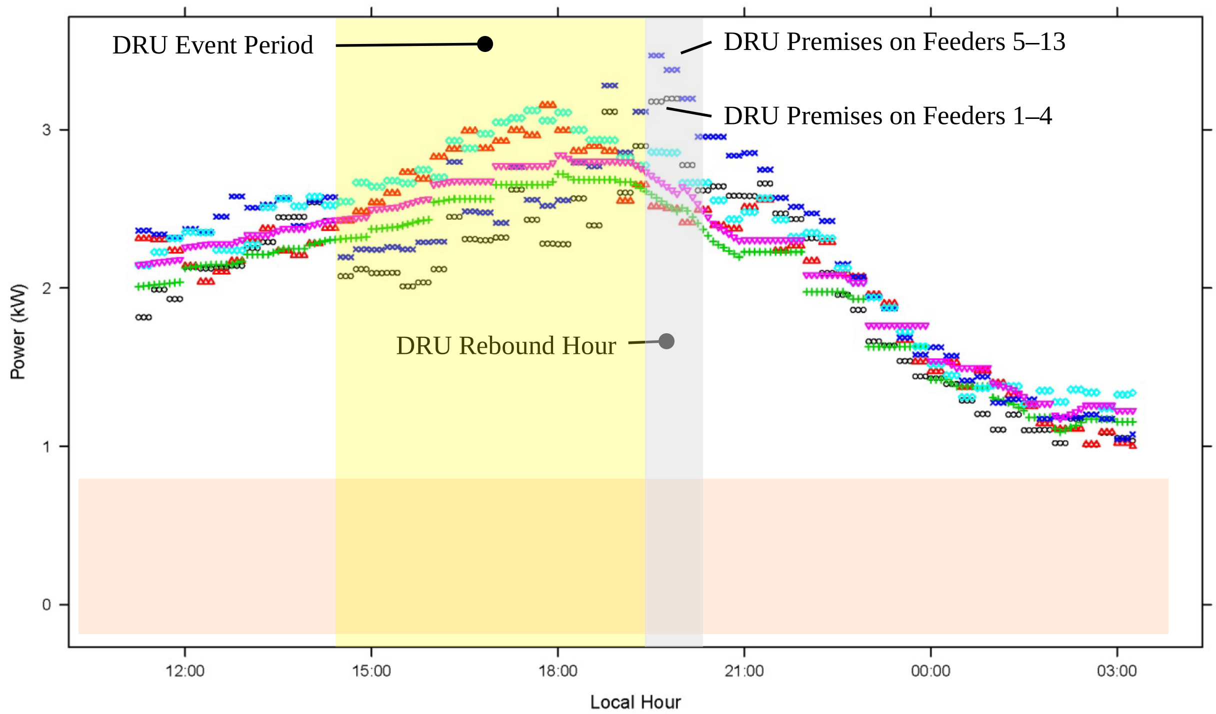


Figure 13.9. DRU Curtailment Event from July 15, 2014. This is an example of multiple events separated by less than one hour using a software control feature provided by the vendor. The averaged DRU premises loads supplied by Feeders 5–13 (blue "x"s) and Feeders 1–4 (black circles) were affected by the curtailment period (yellow shading) and rebound hour (gray shading), but the rebound effect was less pronounced. The other time series are from various Milton-Freewater premises that did not have DRUs.

The Milton-Freewater site configured a transactive function to advise the city when the DRUs should be curtailed. Predicted events further modeled and predicted the total change in city load if the DRUs were to become curtailed by the transactive system. The predicted curtailment impact from 800 water heaters should be 160–640 kW, depending on the time of day the event occurred. The transactive function used by the project to model water heaters was not yet sophisticated enough to predict the magnitude and duration of the rebound effect after the curtailment event is halted.

Altogether 95 transactive events were requested by the transactive system from the Milton-Freewater DRU system from December 2012 through August 2014. Figure 13.10 shows the distribution of these events by day of week, and Figure 13.11 shows how the events' starting times were distributed by local (Pacific Time) hour. Most of the events occurred in midmorning when electricity demand is often great at Milton-Freewater. The average advised transactive event was 1 hour 43 minutes long. The median was 1 hour 5 minutes. The durations ranged from 5 minutes to over 11 hours, but the extremes probably occurred while the project struggled to correctly configure the automation to respond to the utilities' preferences.

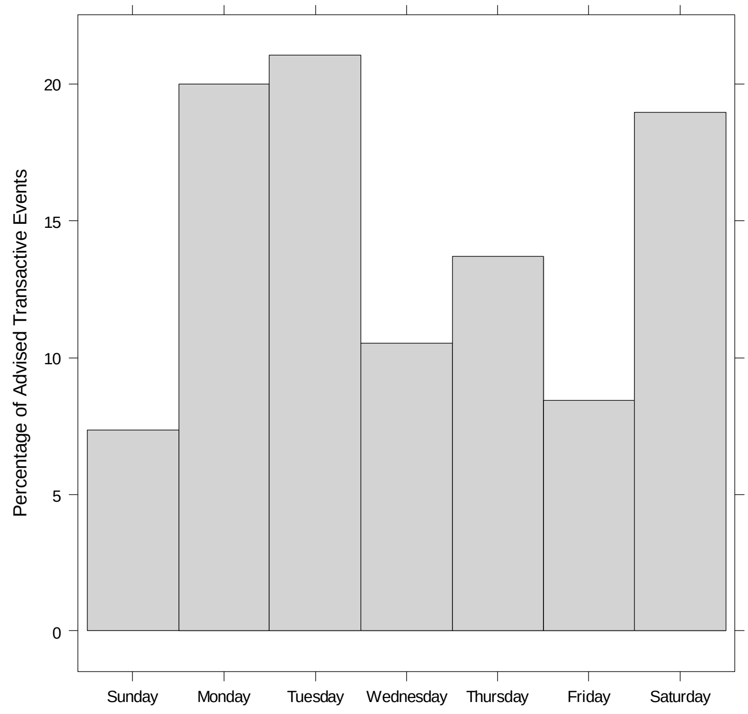


Figure 13.10. Advised Transactive DRU Events by Day of Week

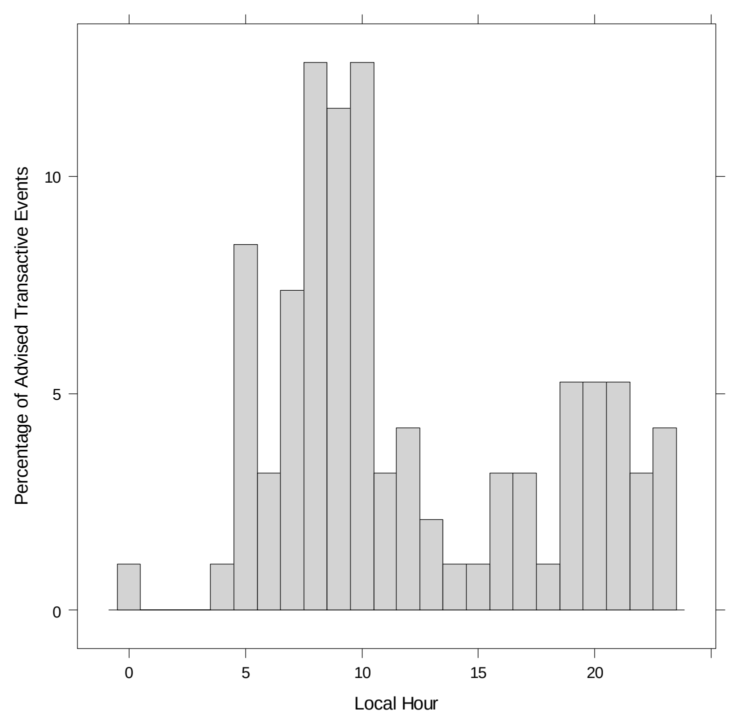


Figure 13.11. Advised Transactive DRU Events by Hour

13.2.2 DRU System Performance

Analysts attempted to verify the impacts from the DRUs by comparing a set of residential premises equipped with DRUs against a similar set of residential premises that did not have DRUs and had been normalized to have similar monthly average power and standard deviation as the experimental group. The resulting baseline emulates average premises power for premises that have no DRU. This chapter will refer to this baseline as the *control baseline*. It will be compared against average DRU premises power to infer the impacts of DRU curtailments.

See the City of Milton-Freewater Layout Diagram, Figure 13.1. Comparisons were conducted separately for Feeders 1–4, which were potentially affected by the city's CVR tests (Section 13.5), and Feeders 5–13, which were potentially affected by the city's dynamic voltage management (Section 13.3). These two sets of feeders experienced different experimental voltage management strategies that could potentially confound observations of DRU performance.

Another pair of baselines was constructed, based on linear regression models of premises having DRUs. The resulting baseline again emulates what the average premises power would have been if the premises had not had DRUs. These baselines will be called *modeled baselines*. Separate modeled baselines were created for premises on Feeders 1–4 and Feeders 5–13 because voltage was being managed differently in those two sets of feeders. Analysts used R software (R Core Team 2014) to conduct the linear regression and to create the modeled baselines. Average premises power was modeled as a function of ambient temperature, separately assessed by month, day of week, and hour of day. The event statuses concerning voltage management in Feeders 1–4 and 5–13 were also used by the regression to help avoid the potentially confounding impacts of the voltage management in those two feeder sets.

Curtailment of an electric water heater in the Pacific Northwest could defer consumption of up to 0.8 kW, on average, during peak hours. Much of the curtailed energy is expected to be consumed after the water heaters are returned to normal operation as the water heaters heat cold water that entered the bottom of the tank during the curtailment period. The maximum benefit for this system of 800 DRUs would therefore be about $54,000 per year, presuming the city could correctly predict and respond to every monthly peak hour for which it will incur demand charges.[1]

The demonstration could confirm only a fraction of the theoretically achievable benefit using its analysis methods and the data that it collected. Actual curtailment events and advised transactive events largely failed to identify the monthly hours on which demand charges were, in fact, incurred. This means that one of the major available monetary benefits was not, in fact, earned by the city. The demonstrated impacts were also reduced by asset installation and implementation, in that many of the curtailments were not acted upon early in the demonstration period due to a software error. Finally, the demonstrated impacts were reduced because the analysis results were affected by both the actual asset performance and the performance of premises metering and data collection processes.

[1] This maximum benefit assumes the following: (1) demand charges are presently incurred during nine project months each year, (2) there are 800 active water heaters, (3) each water heater defers 0.8 kW, on average, while it is being curtailed, (4) the average demand rate is $9.32 / kW, and (5) the change in peak demand from the DRU system is not large enough to completely avoid demand charges.

Residential premises metering allowed the project to compile 15-minute aggregated customer power data. The city marked these data according to the test assets that they possessed and the feeder on which the premises resided. The project aggregated the premises data according to asset ownership and separate groups for Feeders 1–4 and 5–13. The city also provided the project an event indicator when the DRUs were, according to their records, curtailed and released.

The project first reviewed the performance of the DRU's performance during the curtailment periods. The analysis was separately conducted for the two feeder groups and by baseline type. Monthly results from both the controlled and modeled baseline approaches suggest that the system performance improved and became more consistent over time during the project. This can be seen explicitly in the following plots of *cumulative* energy change and customer hours. Results for Feeders 5−13 are shown below. Similar analysis could be done for circuits 1–4.

To understand these plots, first consider Table 13.2, which shows a few representative rows out of the 185 event records contributing to this analysis.

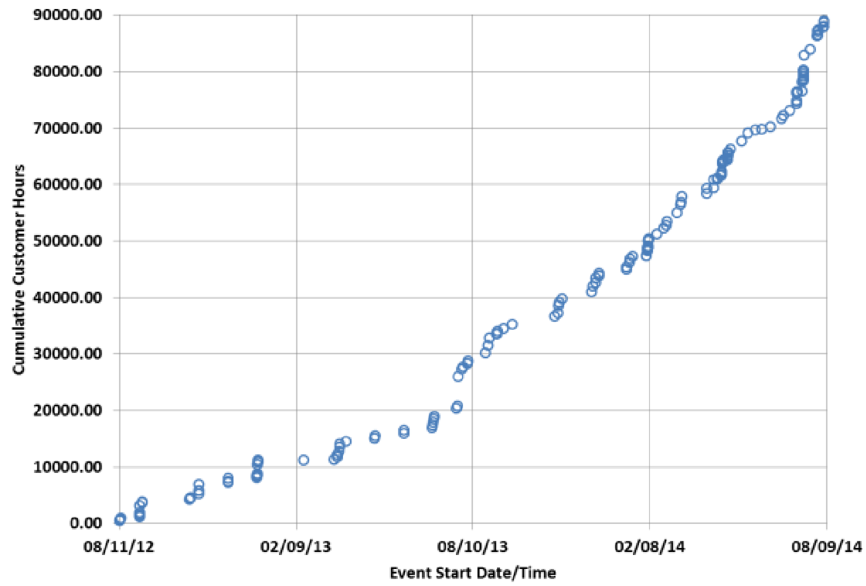
Table 13.2. Representative Rows from a Table for Accumulating Customer Hours and Total Energy Impact by Event and Cumulatively

Event Index	Event Start Date and Time	Event Duration (Hours)	Average Number of Premises	Customer Hours[a] (Hours)	Cumulative Customer Hours (Hours)	Event Energy[b] (kWh)	Total Cumulative Energy[b] (kWh)
1	8/11/2012 4:55	1.33	403.8	538.4	538.4	58.0	58.0
2	8/11/2012 22:40	0.67	404.0	269.3	807.8	21.6	79.6
3	8/12/2012 16:40	0.67	388.0	258.7	1066.4	40.1	119.7
4	8/31/2012 17:40	0.33	403.3	134.4	1200.8	29.7	149.4
…	…	…	…	…	…	…	…
185	8/11/2014 14:30	0.08	468.0	39.0	89055.9	−4.6	−5486.9

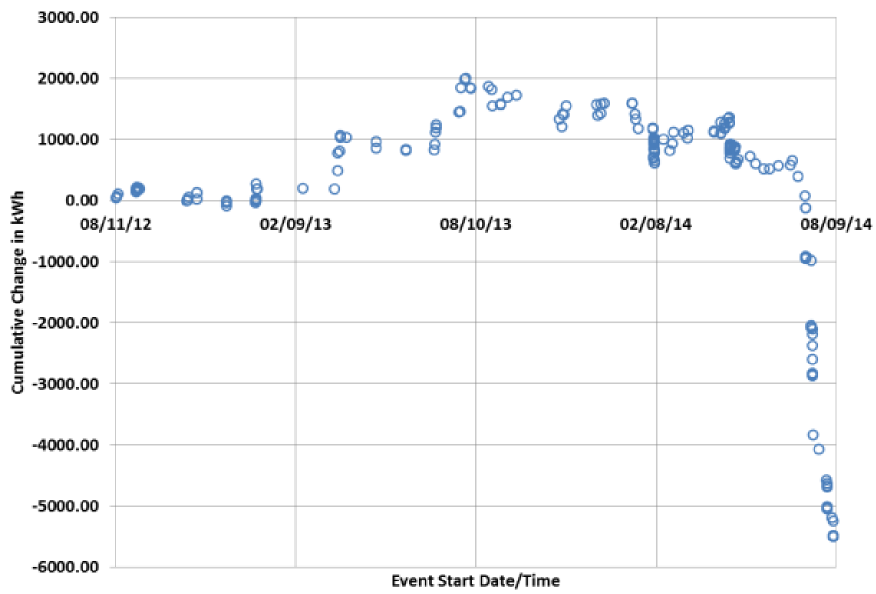
(a) Customer hours were calculated as the product of event duration and average number of premises.

(b) Positive energy values in these columns mean that the DRUs were analyzed to have *increased* energy consumption, as was the case for the first events that are shown here.

The next figure shows two of the columns from the above table. Plots of cumulative customer hours and total cumulative change in energy versus the events' starting times are shown in Figure 13.12a and Figure 13.12b, respectively. The cumulative customer hours show a steady increase as the DRUs were exercised during the project term. The accumulation of customer hours accelerated some over time. However, the cumulative energy benefit was random, even harmful, until late in the project, according to the project's analysis methods and data. A consistent energy benefit was illusive until late summer 2014.



(a) Cumulative Customer Hours



(b) Total Cumulative Change in Energy

Figure 13.12. Cumulative Sums over Time of (a) Customer Hours and (b) Total Analyzed Change in Energy during Event for the 185 Events in this Analysis

Figure 13.13 is a very instructive that combines the cumulative customer hours and cumulative energy impacts that were shown in Figure 13.12. The plot shows DRUs providing little or no reduction in energy in the beginning periods of the project, with gradual improvement, presumably as problems are resolved, and finally steady performance. The slope of the red line toward the end of the project is about 0.27 kW per customer, meaning that each DRU was reducing its owner's electric load by about 0.27 kW during the project's last events.

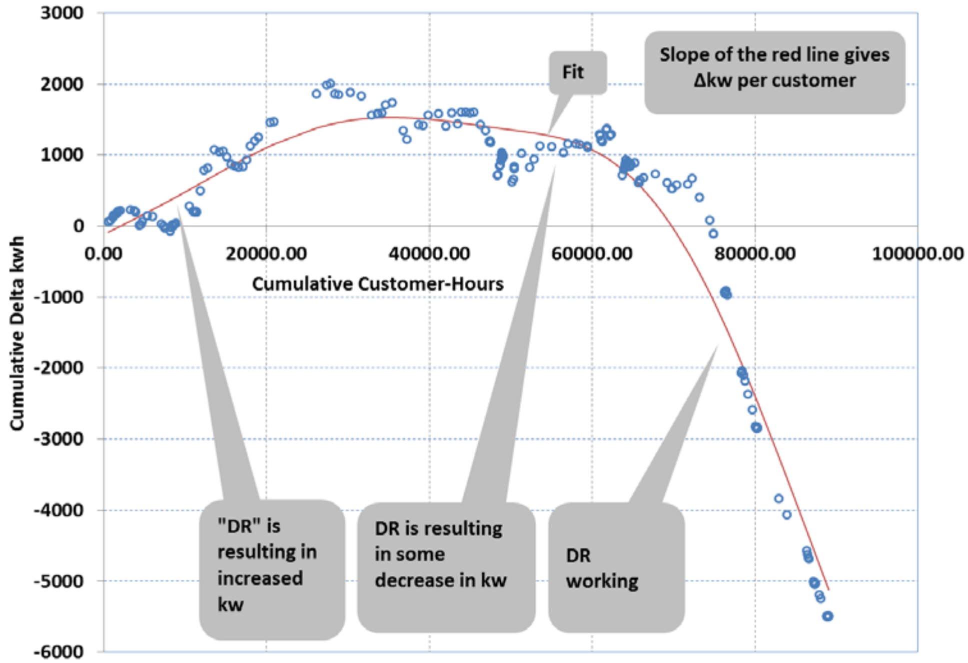


Figure 13.13. Cumulative Energy Impact versus. Cumulative Customer Hours for the Milton-Freewater DRUs during the Term of the PNWSGD

Figure 13.14 shows many of the same observations, but a statistical impact on average premises power during DRU events is shown for each project month. The monthly results were predominantly reductions in power after the first half or so of the project term. The entire figure represents averaged changes in power per premises during events upon comparing with modeled baselines. The impact is defined as the average DRU premises power consumption during the months' events minus the averages from the corresponding baselines. The blue markers are results for Feeders 1–4, and the dashed black markers are for Feeders 5–13. The heavier vertical bars approximate standard error and the longer bars approximate 95% confidence intervals for results from the given months.

The confidence intervals correspond to statistical confidence in the calculated average impact, based on a Student's t-test. The intervals are a little too optimistically stated because they presume independent samples, which is not fully true. The standard deviations of the differences are much larger than the intervals shown for the averaged results. The project was unable to determine why results in November 2012 and June 2013 showed large *increases* in power, which appear to have been outliers among the other results.

The results at the far right-hand side of Figure 13.14 are for *all* curtailment periods during the project, as calculated using the modeled baselines. The overall averaged results are reductions per DRU premises of 110 ± 10 W for Feeders 1–4 and 100 ± 10 W for Feeders 5–13 during the curtailment periods. The agreement between the results for the two feeder sets is strong.

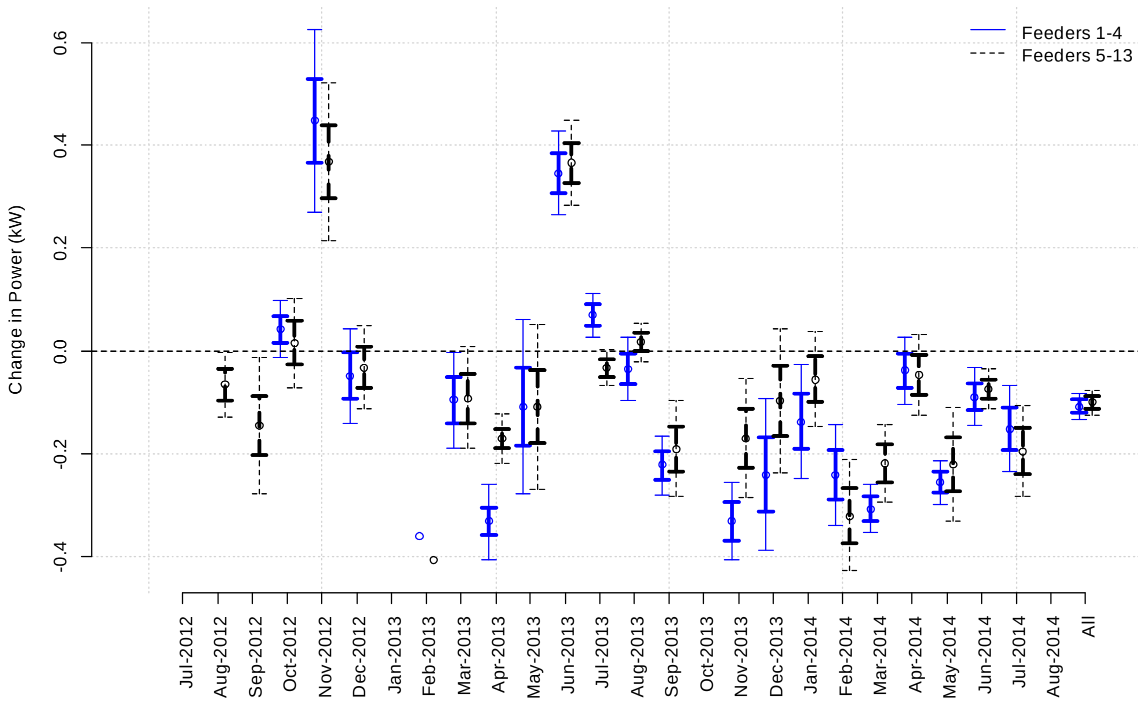


Figure 13.14. Event Statistics by Project Month Based on the Modeled Baselines for Feeders 1–4 (blue) and Feeders 5–13 (black dashes)

A similar analysis was conducted concerning impacts during DRU curtailments using the controlled baselines. The monthly summaries are shown in Figure 13.15; however, the reader should refer back to the discussion from Figure 13.14 concerning the interpretation of the diagram, which will not be repeated.

Again, there appears to be a trend toward improvement (i.e., more power reduction) and consistency over the period of the demonstration. The comparison of the populations was affected by the variability in both the test and normalized control populations. The method proved resilient against pervasive data issues that sometimes fooled the modeled-baseline approach.

The largest *positive* results occurred in the Feeder 5–13 test population for months March 2013 and June 2013. The results in the last two demonstration months, July and August 2014, showed convincing reduction in premises power during the DRU curtailments. Overall, the comparison-baseline approach estimates the per-premises reductions to be 110 ± 10 W for Feeders 1–4 and 60 ± 10 W for Feeders 5–13.

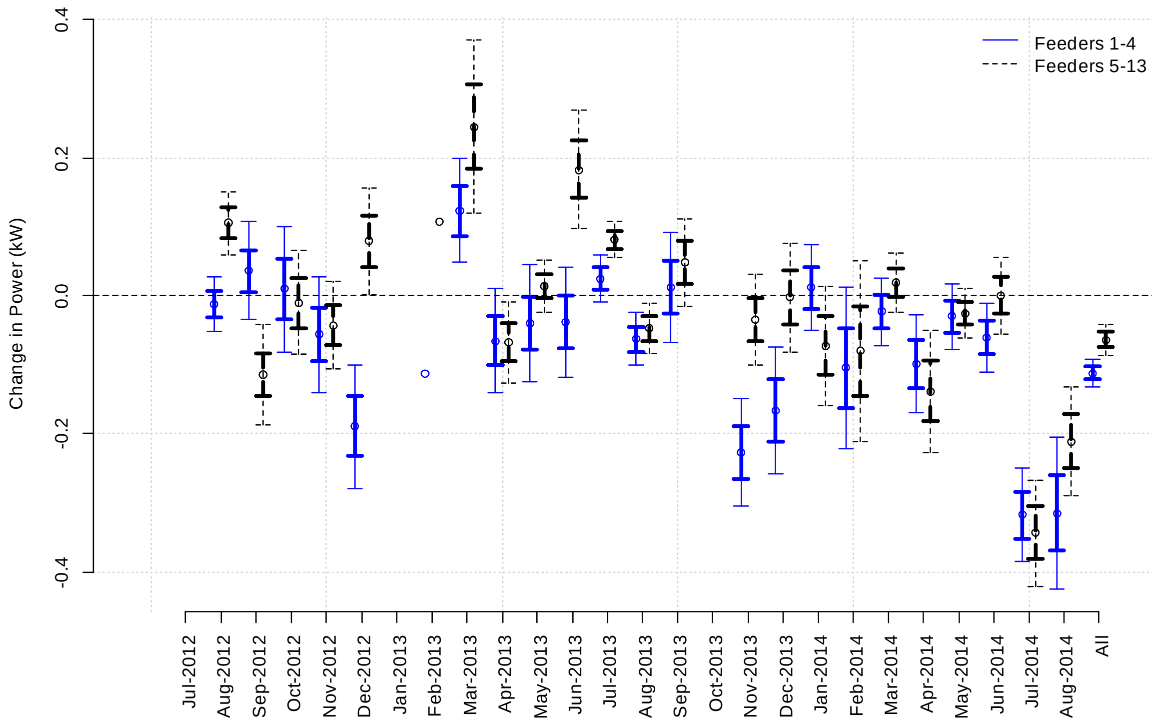


Figure 13.15. Event Statistics by Project Month Based on the Controlled Baselines for Feeders 1–4 (blue) and Feeders 5–13 (black dashes)

The best single estimate of the confirmed per-premises reduction in power during DRU curtailments initiated by the project is therefore a reduction of 100 ± 10 W. Here the variability has been stated as the standard deviation of the results from the two methods. This is less than one-half of the reduction that should be expected according to typical diurnal power consumption by tank electric water heaters. This estimate would have been greater had the demonstrated system performance early in the project matched that at the end.

The project next looked at the rebound impact, which will be defined as the average change in premises power during the hour that immediately followed the conclusion of any DRU curtailment. The month-by-month variability of the impact from the modeled-baseline approach is large, as shown in Figure 13.16. A reason for the increased uncertainty is that data is limited to a single hour per event. No clear pattern in time may be discerned in this figure as the project term progresses. However, based on all project data and using the modeled baselines, the average power increased 40 ± 20 W and 60 ± 20 W, on average, during the rebound hours for Feeders 1–4 and Feeders 5–13, respectively.

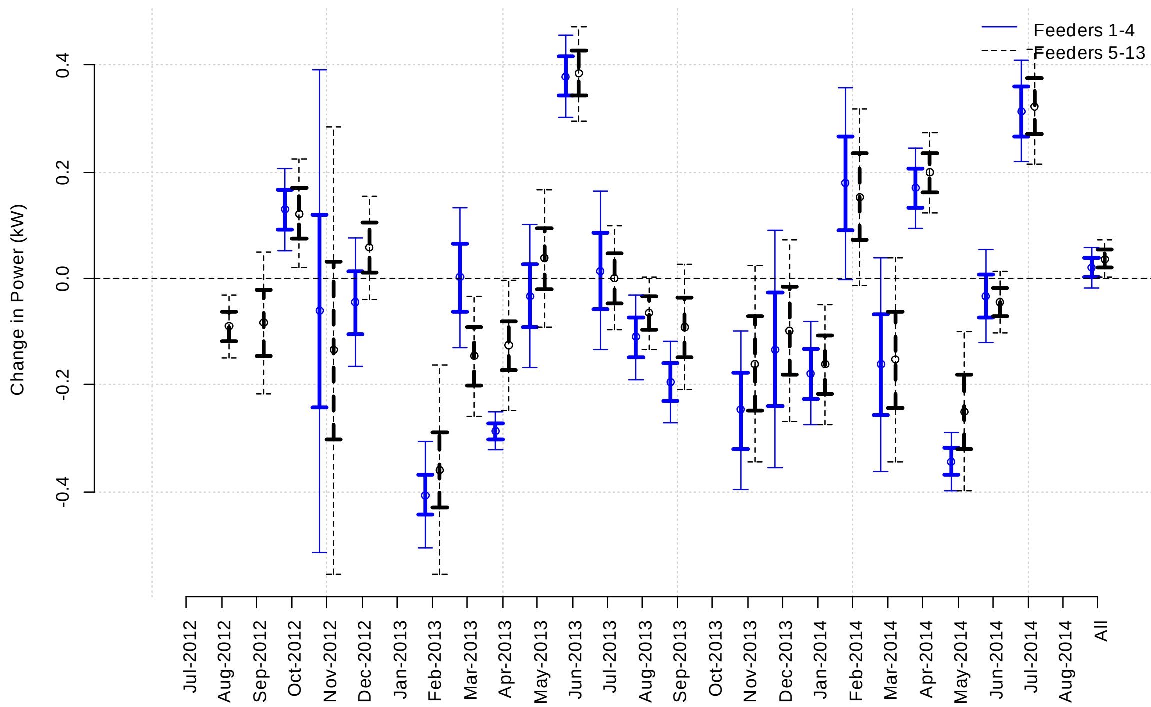


Figure 13.16. Rebound-Hour Statistics by Project Month Based on the Modeled Baselines for Feeders 1–4 (blue) and Feeders 5–13 (black dashes)

Using the controlled baselines, the rebound-hour impact may be estimated as an increase per premises of 70 ± 10 W and 110 ± 10 W for Feeders 1–4 and Feeders 5–13 during the hours following DRU curtailments (Figure 13.17). Using this controlled baseline, we observe a trend toward greater and more consistent rebound impacts toward the end of the project.

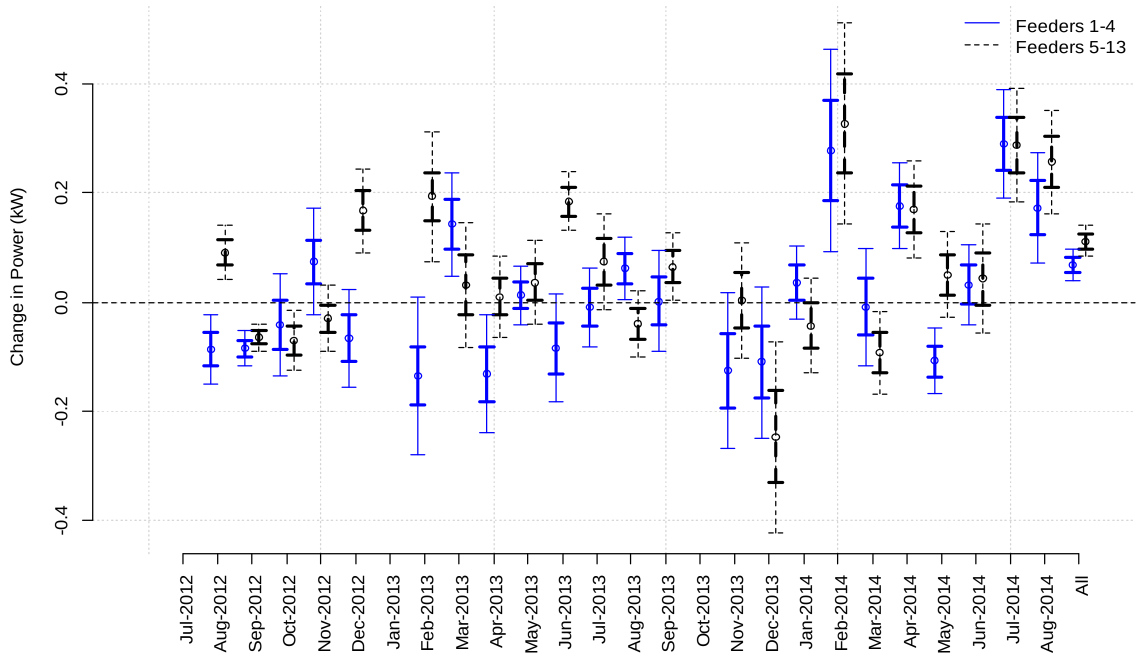


Figure 13.17. Rebound-Hour Statistics by Project Month Based on the Controlled Baselines for Feeders 1–4 (blue) and Feeders 5–13 (black dashes)

The modeled baselines yielded smaller, more conservative estimates of the rebound impact than did the controlled baselines. Upon averaging the results from both baselines and for both sets of feeders, the project reports an average increase of power per premises of 70 ± 30 W during rebound hours. Again, the variability used here is the standard deviation from the results of using the two baseline types. This result is probably conservative. The deferred energy demands from the curtailment of water heaters may result in short-term peaks like those evident in Figure 13.7 and Figure 13.8 when the water heaters are released from curtailment. The spike may be even greater than the averaged magnitude that is being reported here for an entire hour following DRU curtailments.

Next, the project evaluated the entire days on which DRU curtailments had occurred. Upon reviewing results from using the modeled baselines (Figure 13.18), a small average reduction might be reportable for Feeders 1–4 (7 ± 4 W), but neither a reduction nor an increase can be confidently reported for Feeders 5–13.

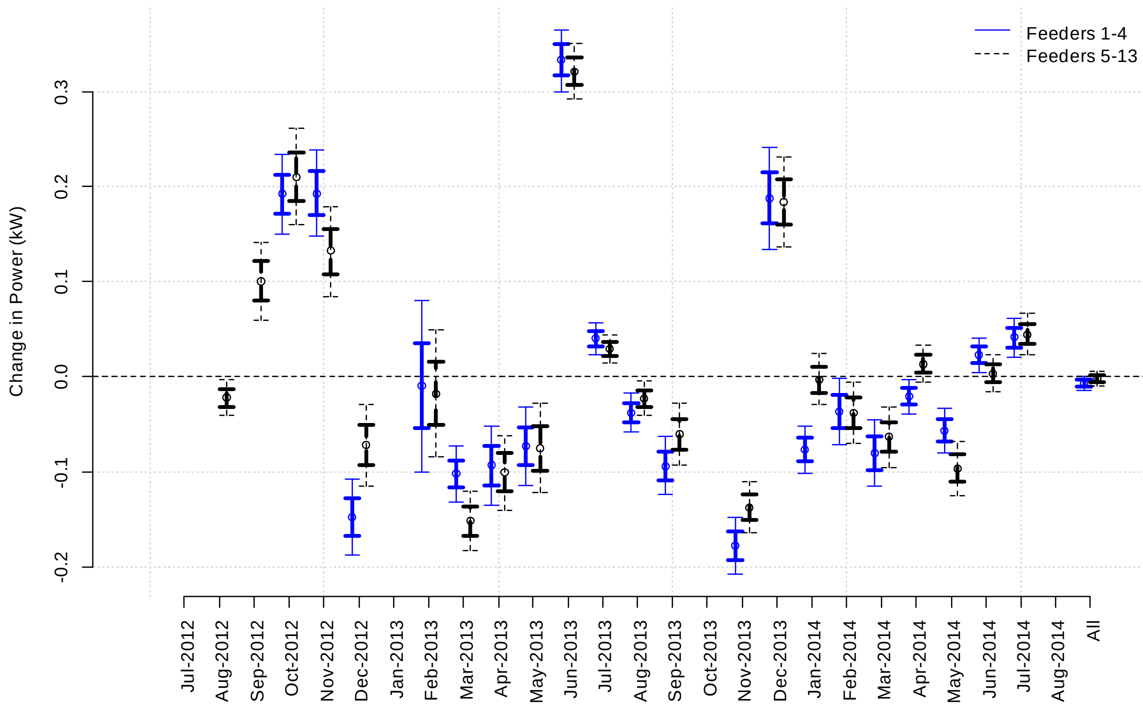


Figure 13.18. Event-Day Statistics by Project Month Based on the Modeled Baselines for Feeders 1–4 (blue) and Feeders 5–13 (black dashes)

The impact of DRU events throughout event days was inconclusive using the comparison-baseline approach (Figure 13.19). Contradictory results were obtained for the two feeder sets. A moderate decrease seemed to occur for Feeders 1–4 (10 ± 2 W), but an increase of similar magnitude occurred for Feeders 5−13 (8 ± 3 W).

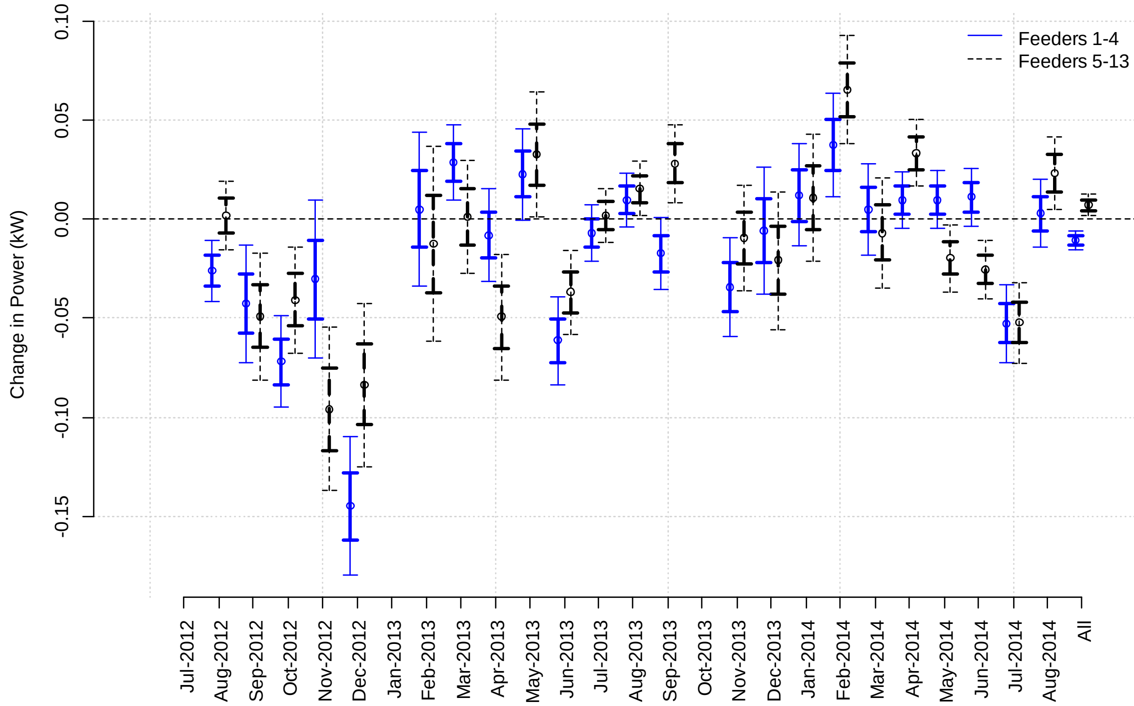


Figure 13.19. Event-Day Statistics by Project Month Based on the Controlled Baselines for Feeders 1–4 (blue) and Feeders 5–13 (black dashes)

The project therefore reports that there was virtually no impact confirmed concerning any change in the energy that was consumed on days that DRU curtailments had occurred (a reduction of 2 ± 2 W). This result is probably sensible. It means that the energy that was curtailed during DRU events is most likely simply deferred to another time that same day. Little or no actual conservation occurred.

Table 13.3 summarizes the value of the supply energy that is curtailed while the DRU events are active. The sum energy during the HLH and LLH may be used to estimate the value of this energy using BPA's load-shaping rates (Appendix C). Only a small amount of energy, about 7 MWh per year is avoided during the year's events, and the wholesale value of this energy to the city is about $232 ± 23. This impact would likely have been greater had the performance of the DRUs early in the project matched their performance at the end.

Table 13.3. Estimated Supply Energy and the Value of Supply Energy Displaced each Calendar Month by Milton-Freewater's DRU Events

	HLH		LLH		Total	
	(kWh)[(a)]	($)[(b)]	(kWh)[(a)]	($)[(b)]	(kWh)[(a)]	($)[(b)]
Jan	−378 ± 83	−14 ± 3	−64 ± 11	−2 ± 0	−442 ± 84	−16 ± 3
Feb	−890 ± 280	−33 ± 10	−27 ± 1	−1 ± 0	−920 ± 280	−34 ± 10
Mar	−520 ± 110	−16 ± 3	145 ± 71	4 ± 2	−380 ± 130	−12 ± 4
Apr	−880 ± 250	−23 ± 6	−47 ± 8	−1 ± 0	−930 ± 250	−24 ± 6
May	−461 ± 62	−10 ± 11	23 ± 5	0 ± 0	−438 ± 62	−9 ± 1
Jun	240 ± 140	5 ± 3	263 ± 22	4 ± 0	500 ± 140	9 ± 3
Jul	−2,400 ± 490	−73 ± 15	0	0	−2,400 ± 490	−73 ± 15
Aug	−1,010 ± 190	−34 ± 6	44 ± 24	1 ± 1	−970± 190	−33 ± 6
Sep	−190 ± 80	−6 ± 3	0	0	−190 ± 80	−6 ± 3
Oct	141 ± 42	4 ± 1	−29 ± 25	−1 ± 1	112 ± 49	4 ± 1
Nov	−610 ± 120	−22 ± 4	126 ± 72	4 ± 2	−480 ± 140	−18 ± 5
Dec	−290 ± 180	−11 ± 7	−237 ± 66	−8 ± 2	−530 ± 190	−19 ± 7
Totals	**−7,250 ± 720**	**−232 ± 23**	**200± 130**	**0 ± 4**	**−7,050 ± 730**	**−232 ± 23**

(a) The energy is negative in these columns if the net energy consumption was reduced according to the project's analysis methods and project data.

(b) The dollar amounts in these columns are negative if the utility has reduced its purchase of wholesale supply energy according to the project's analysis.

Table 13.4 was created to help estimate the impacts of the DRUs on Milton-Freewater's demand charges. A preliminary table (not shown) was created to compile the average impact that DRU events had during the HLH hours of every calendar month. The city provided the project a list of historical hourly peak hours that could then be compared with the preliminary table. The peak hours were used to weight the hourly impacts each calendar month. If no events had been exercised on any of the peak hours in a given calendar month, the DRUs were given no credit that month for reducing demand charges. Also, no credit was given toward reduction of demand charges any month that the city had not, in fact, incurred demand charges. The estimate of peak-demand impact is probably still generous or optimistic because it presumes that the utility will accurately apply the DRUs during not only the correct hours, but also during the right day of each month.

The impact of the DRUs on average HLH hours (aHLH) were calculated simply by summing the energy impacts during all of a month's HLH hours and dividing by the number of HLH hours in that month.

Finally, the effect on monthly demand charges was calculated by multiplying the differences between the demand and aHLH components by the BPA demand rate (Appendix C). If the system of DRUs were operated as it was during the PNWSGD, and if the events were accurately placed coincident with the monthly peak hours, the city might reduce its BPA demand charges by $4,400 ± 1,300 per year. This impact, again, would likely have been greater had the performance of the DRUs early in the project matched the quality of their performance at the end.

Table 13.4. Estimated Impact of Milton-Freewater's DRUs on the Utility's Demand Charges

	Δ Demand[(a)] (kW)	Δ aHLH[(a)] (kWh/h)	Δ Demand Charges[(b)] ($)
Jan	0	0	0
Feb	−292 ± 93	−2 ± 0	−3,161 ± 1,014
Mar	124 ± 46	−1 ± 1	1,116 ± 411
Apr	−257 ± 66	−2 ± 0	−1,941 ± 502
May	0	0	0
Jun	0	0	0
Jul	−145 ± 34	−6 ± 0	−1,252 ± 306
Aug	−47 ± 38	−2 ± 1	−451 ± 381
Sep	0	0	0
Oct	217 ± 8	0	2,025 ± 75
Nov	−65 ± 12	−2 ± 1	−662 ± 126
Dec	−10 ± 18	0	−115 ± 206
Total			**−4,400 ± 1,300**

(a) A negative demand value in this column means that the demand determinant was reduced, according to the project's analysis and data.

(b) Negative dollar amounts in this column mean that the utility's demand charges were decreased, according to the project's analysis.

13.3 Conservation-Voltage-Regulation Peak Shaving

The City of Milton-Freewater configured nine of its distribution feeders (Feeders 5–13) to reduce their voltages by 4.5% (3 transformer tap settings) during events when curtailment was advised. These events typically lasted several hours. The voltage was returned to normal at the conclusion of each event.

The main impetus for short-term power reduction for the city was avoidance of BPA demand-charge increases. The city's cost impact from demand charges was represented and predicted by a transactive function, so this objective should have been met to the degree that monthly peaks were accurately predicted by the function.

Energy consumption might also have been moved out of heavily loaded hours, when energy is more expensive, to lightly loaded hours. However, the project failed to represent the different costs of heavily and lightly loaded hours at this site through its transactive system, so this objective was not achieved by the transactive system.

If voltage-responsive DRUs (Section 13.4) had not been collocated on these distribution feeders, the city would have perhaps allowed more frequent voltage reductions, and for longer durations. However, the city did not want customers who had voltage-responsive DRUs to be inconvenienced. So, the transactive system at this site was configured to allow few, short voltage-reduction events. The voltage-responsive DRUs necessarily responded to the voltage reduction on Feeders 7–10. Great care was needed by analysts to isolate independent impacts from the voltage reduction itself and the consequent curtailment of the voltage-responsive DRUs.

The city’s distribution system is relatively urban. Conductor lengths are short. Based on prior analysis, the city asserted that there was no significant risk that reducing supply voltage by 4.5% would degrade customer power quality. Their system, in their assessment, did not require persistent end-of-line feedback monitoring of end-of-line voltage to be built into their control system.

The annualized costs of system modifications have been summarized in Table 13.5. The city already had installed the tap-changing transformers that were needed for this voltage management system. A fraction of the additional software and engineering costs to automate the tap changers and to make them respond to the project’s transactive system was shared among this and other site asset systems. The city also elected to apply one-third of the costs of updated premises metering to this asset system.

Table 13.5. Costs of the Milton-Freewater Voltage Management on Feeders 5–13

	Shared Usage of Component (%)	Annualized Component Cost ($K)	Allocated Annual Component Cost ($K)
Residential and Commercial Advanced Meters	33	270.3	90.0
Programming for Automatic Control of Voltage SCADA	50	11.0	5.5
Transactive Node	33	9.8	3.2
Total Annualized Asset Cost			**$98.7K**

13.3.1 Characterization of the CVR Peak-Shaving System Responses

The City of Milton-Freewater reported to the project the times during which it had reduced voltage on Feeders 5–13 by three tap settings, or 4.5%. This list of events was found to be somewhat inaccurate when the project compared the list against distribution voltages measurements that had been reported by Milton-Freewater to the project. Figure 13.20 demonstrates this inaccuracy. The times that voltage had been intentionally reduced are evident, and these voltage fall well below 1.0 per unit. The data during reported event times are shown in red. Some voltage reductions were accurately reported, but there are also many unreported voltage reductions and reported events that had evidently not been responded to. The cause of these inaccuracies is not known.

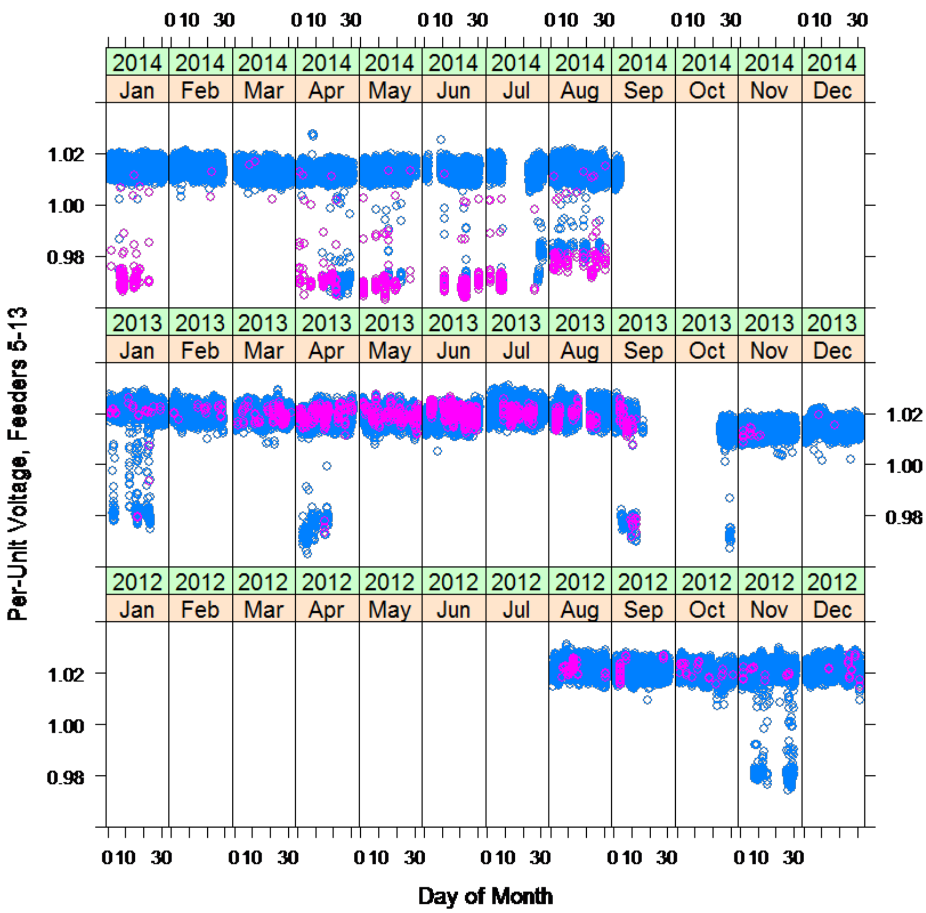


Figure 13.20. Correlation between Periods when the Average Distribution Voltage on Feeders 5–13 is Reduced (blue) Versus the Periods when it is Reported to have been Reduced (red)

Fortunately, a histogram of averaged per-unit voltage on these feeders showed a fairly clear distinction between the feeders' normal and reduced voltages. The voltage was found to have been controlled to an intermediate level, perhaps one transformer tap reduction, during September 12–16, 2013 and again July 18–21, 2014. These two periods were discarded from the analysis so that a clean comparison could be made between only two settings. The resulting histogram of per-unit voltages is shown in Figure 13.21.

Project analysts elected to infer the true events from the magnitude of the distribution voltage. After the data was scrubbed, those voltages less than or equal to 1.005 per unit were inferred to have been intentional reductions. It is the inferred events, not the reported ones, that were used for analysis and in the discussion that follows. Overall, 217 events were inferred to have been initiated from August 2012 through August 2014. The voltage was found to have been truly reduced 40% of the hours that the voltage had been reported to have been reduced. Events were reported for only 33% of the hours that the voltage had, in fact, been reduced, according to the project's data.

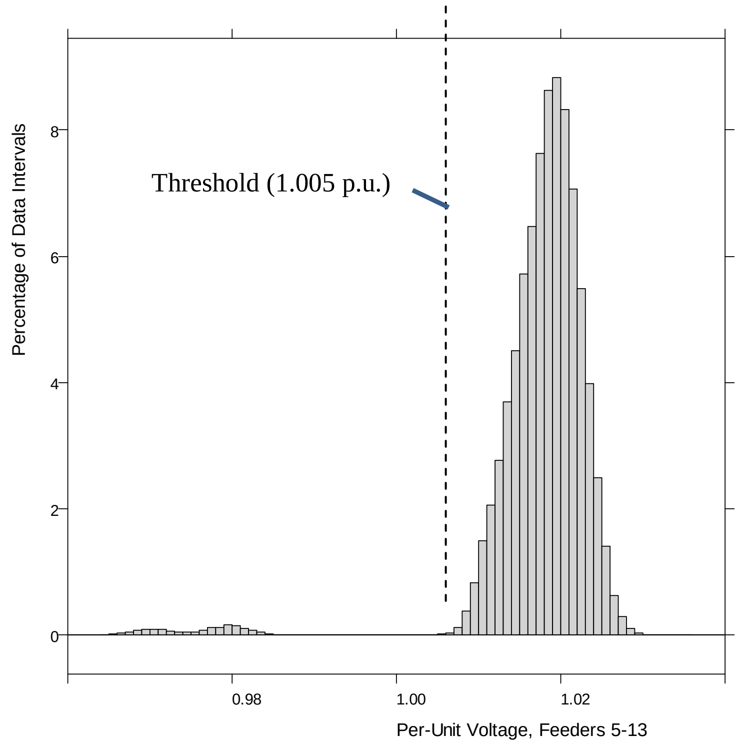


Figure 13.21. Per-Unit Distribution Voltages on Feeders 5–13 after Two Periods having an Intermediate Voltage were Removed

Because the events were necessarily inferred, it is plausible that some of the inferred events are spurious. Figure 13.22 shows that just over 14% of the events were only 15 minutes in duration, the shortest measured interval. However, 5% of the events were only two 15-minute intervals in duration. The project applied no further filtering to determine whether the inferred events might have been intentional or not. The longest inferred interval was 16 hours and 45 minutes long.

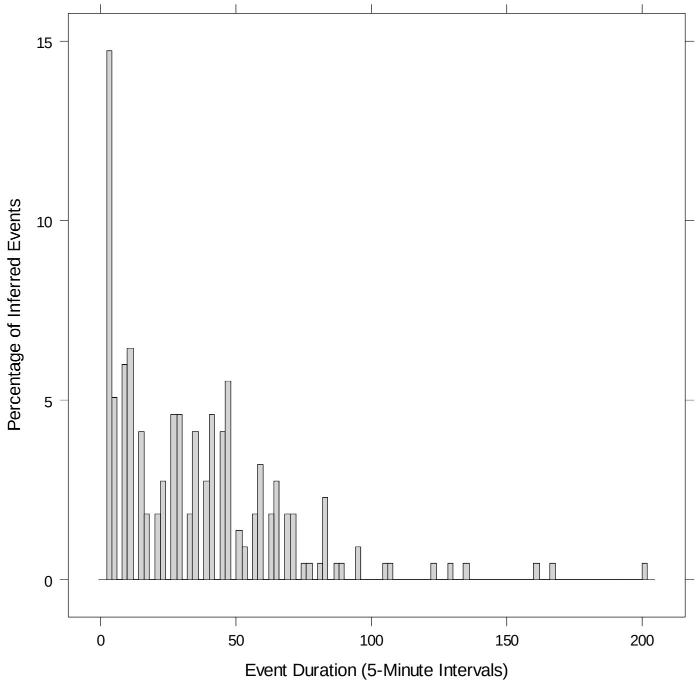
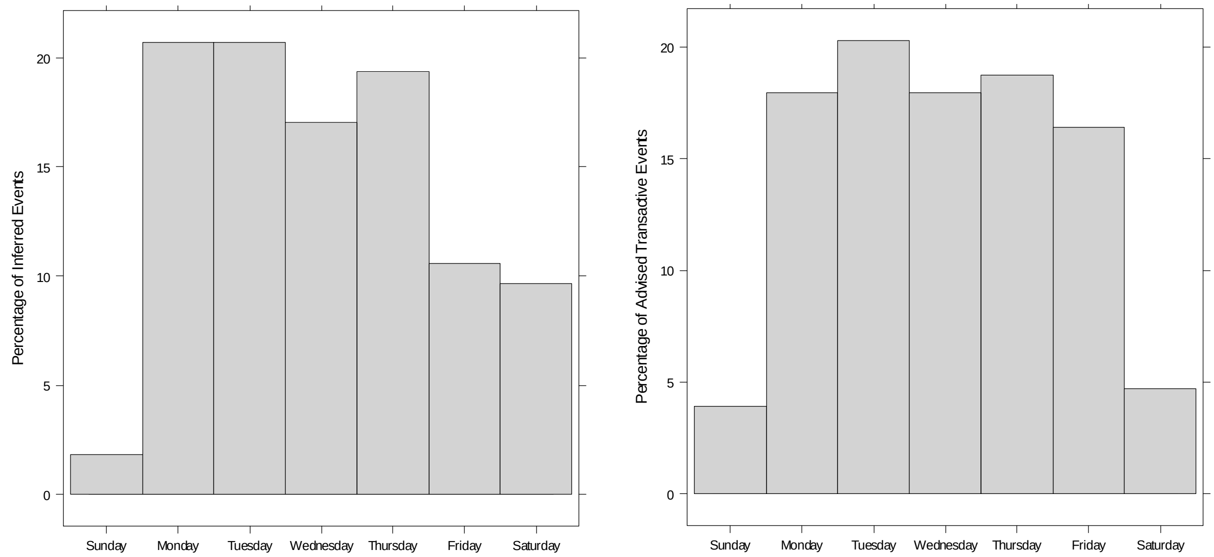


Figure 13.22. Durations of the Inferred Events when Voltage had been Reduced on Feeders 5–13

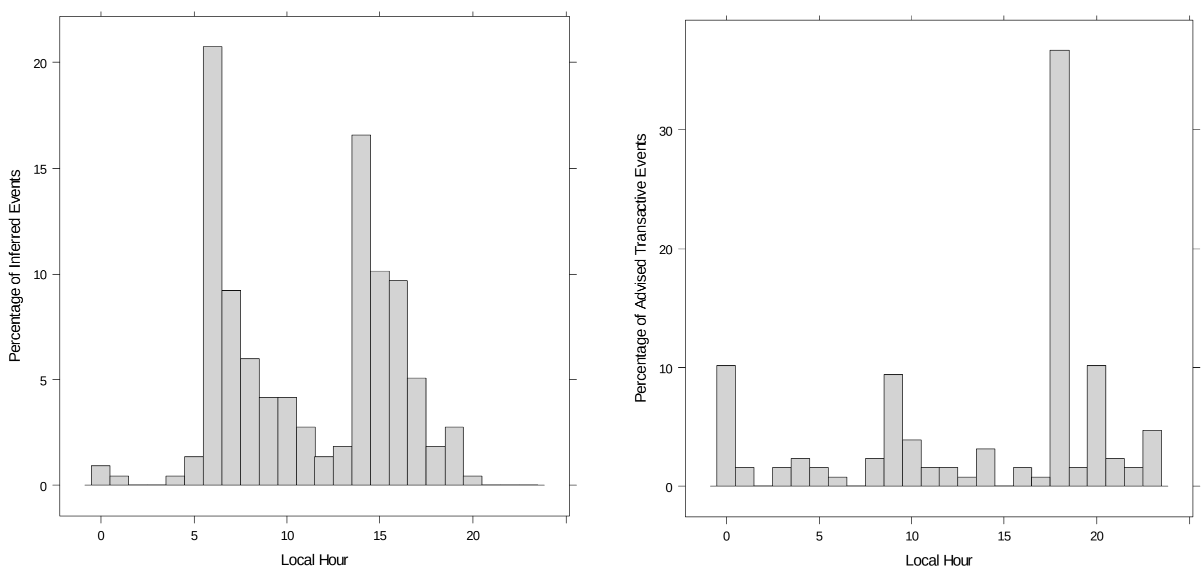
Because this asset system is primarily installed to avoid increased peak demand and its charges, events should mostly occur during heavily loaded hours, which are the only hours that demand charges may be incurred from supplier BPA. This expectation is somewhat confirmed for both inferred events (Figure 13.23a) and advised transactive events (Figure 13.23b). Some of the Sunday events (by definition, BPA heavy-load hours cannot occur on Sundays) may have occurred while Milton-Freewater was working to tune its system. The likelihood that a transactive event will be advised to occur on given weekdays is configured by the code that generates the advice to the asset system. As for other of the project's asset systems, such configuration was often delayed or never finalized.



(a) Inferred Events (b) Advised Transactive Events

Figure 13.23. Days of Week that (a) Inferred and (b) Advised Transactive (right) Voltage Reductions were Initiated

According to Figure 13.24a, the actual voltage reductions were initiated near the hours that Milton-Freewater load reaches its peak load (see Figure 13.2). The hours that the transactive system advised voltage reduction (Figure 13.24b) were not so structured. The transactive system never matured to identify useful response periods for this asset system, and it was not properly configured for this asset system to enact the responsiveness that Milton-Freewater desired.



(a) Inferred Events (b) Advised Transactive Events

Figure 13.24. Hours that (a) Inferred and (b) Advised Transactive Voltage Reductions were Initiated

13.3.2 Conservation-Voltage-Regulation Peak-Shaving System Performance

The theoretical total power reduction during voltage-reduction events should have been from 0.3 to 0.7 MW.[1] Very little, if any, rebound effect should be expected when the voltage is returned to nominal at the conclusion of an event. A transactive function at this site predicted the effect during reduced-voltage events. The function was very simple; it was based on a presumed CVR factor, the designed change in voltage (i.e., three tap settings), and the predicted total load on these feeders at their nominal, unreduced voltage.

While voltage reductions were applied to all the Feeders 5–13, a population of voltage-responsive water heaters was installed on a subset of these feeders (Feeders 7–10) and responded to the same stimulus (see Section 13.4). The project chose to evaluate only Feeders 5, 6, 11, 12 and 13, which were unaffected by the voltage-responsive water heaters, to separate the passive response to the voltage reduction from those of the more responsive water heaters.

Two baseline-comparison methods were used. These baselines parallel those that were developed for analysis of the other asset systems. First, the total power consumption on Feeders 5, 6, 11, 12 and 13 was modeled using linear regression to predict what the power would have been if voltage had not been reduced during events. The regression incorporated the influences of outdoor temperature, separately assessed by month, day of week, and hour of day in this model. The resulting baseline will be called the *modeled baseline*.

Second, the total power consumption on Feeders 1–4, which were not subjected to the same 4.5% voltage reduction, was normalized to have the same monthly average and standard deviation as the total power on the subset of affected feeders, where the short-term voltage reduction was being practiced. Care was taken in this comparison to mitigate potentially confounding impacts from the different voltage levels used for CVR experimentation on Feeders 1–4. The resulting baseline will be called the *controlled baseline*.

The load on both the Feeders 1–4 and the subset of Feeders 5, 6, 11, 12 and 13 may be affected by the status of the system of 800 DRUs on those feeders (see Section 13.2). Those DRUs were collocated among all Milton-Freewater feeders and might confound the evaluation of the effects of short-term voltage reduction. In fact, the DRUs were found to be active 14% of the time the voltage had been reduced. The voltage was reduced 44% of the time that the DRUs were active. Because the DRU events and voltage reduction were often coincident, it was challenging to completely isolate the effects of voltage reduction from the effects of the DRUs. In continuing with the comparison of Feeders 5, 6, 11, 12 and 13 against Feeders 1–4, an implicit assumption must be made that the two sets of feeders are similarly affected by the DRUs.

Analysis yielded a rather surprising result at the distribution level. Figure 13.25 shows the statistical changes in average distribution power each month on the five feeders when voltage was reduced, according to comparisons with the modeled and controlled baselines. Analyses using the controlled and

[1] This prediction assumes a typical CVR factor of 0.8, 4.5% voltage reduction, median total load of 8.9 MW, and peak load of 20.5 MW for these nine feeders.

modeled baselines agreed that there had been an *increase* in electric load while the voltage was reduced on the subset of feeders. Using the modeled baseline, 190 ± 10 kW more power was consumed during events and 40 ± 10 kW more was consumed on the five feeders according to the controlled baseline. The project reports an average 100 ± 100 kW increase for the five feeders while voltage was reduced.

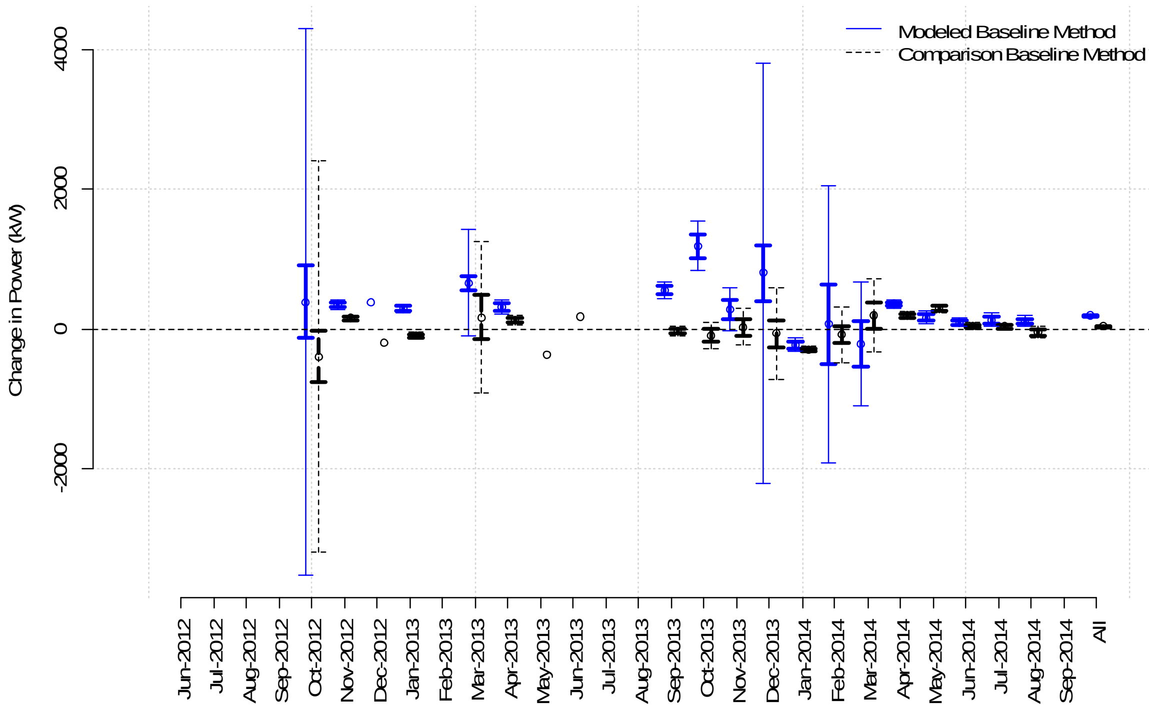


Figure 13.25. Monthly and Project Power Impact on Feeders 5, 6, 11, 12 and 13 while Voltage was Reduced and Using the Modeled (blue) and Controlled (black dashes) Baselines

The project then analyzed the distribution power data on these five feeders to see whether a rebound effect could be detected the hour after voltage had been restored. The statistical average monthly rebound impacts are shown in Figure 13.26 for the project months and using the two baselines. Comparison using the modeled baseline yielded an increase, but no reportable effect can be reported from using the controlled baseline by itself. Upon combining the results of the two methods, the project reports that, on average, 70 ± 80 kW more power was used during rebound hours than at other times. This result is not especially convincing, and it is similar in magnitude to, but less than, the result that was determined during the events.

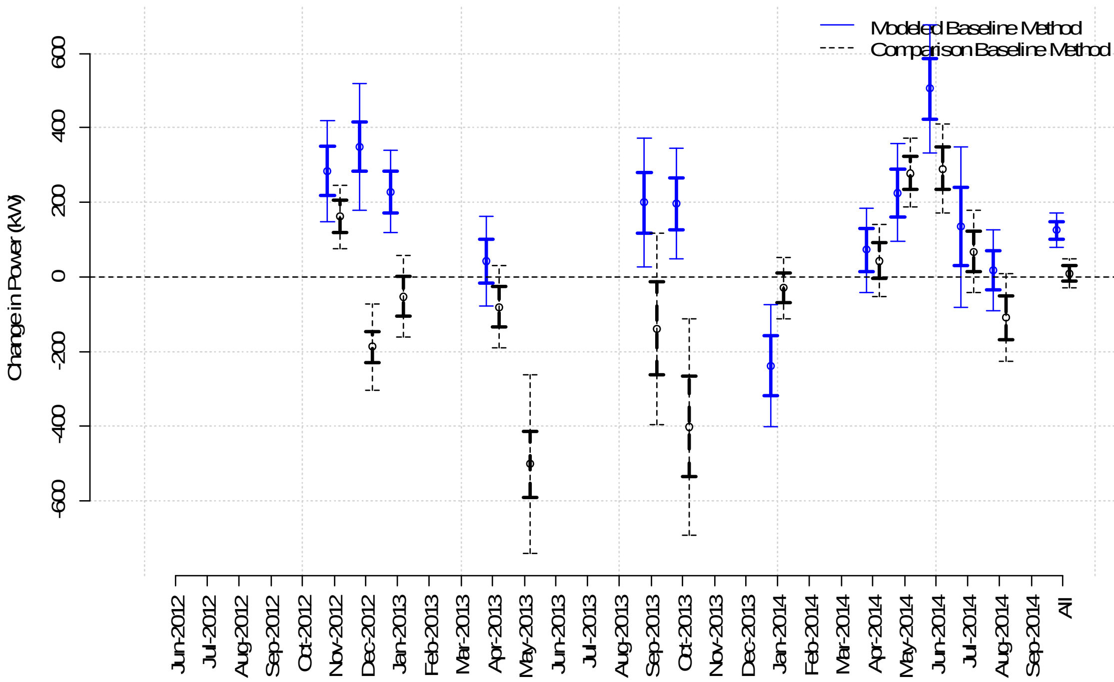


Figure 13.26. Monthly and Project Rebound-Hour Power Impact on Feeders 5, 6, 11, 12 and 13 Using the Modeled (blue) and Controlled (black dashes) Baselines

Finally, the project considered the average impacts throughout event days for days on which the voltage had been inferred to have been reduced. As shown in Figure 13.27, analysis using both baseline types agreed that there was a modest increase in feeder load on the days that voltage had been reduced. The project reports the averaged increase in load as 60 ± 30 kW averaged throughout event days.

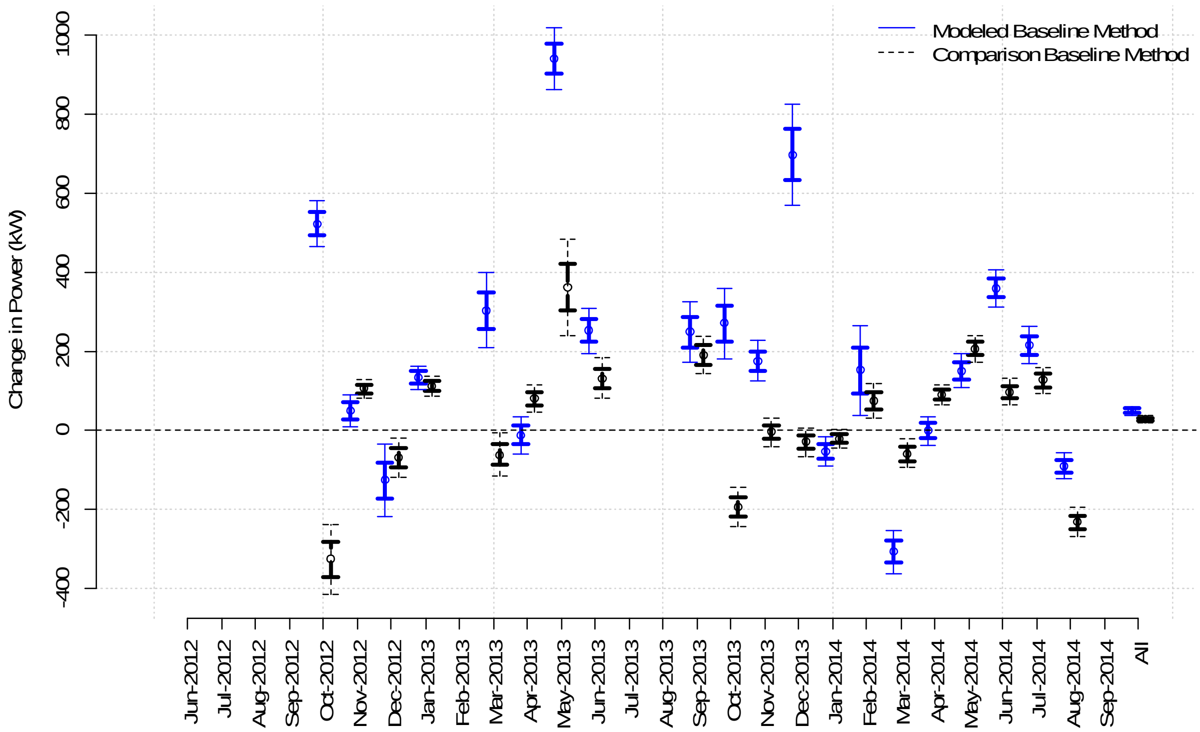


Figure 13.27. Monthly Averaged Event-Day Power Impacts on Feeders 5, 6, 11, 12 and 13 Using the Modeled (blue) and Comparison (black dashes) Baselines

The project also analyzed the impact at a sample of residential premises that are on these affected feeders to determine whether a premises-level effect could be observed. Another regression model was created to model residential power consumption. The model emulated consumption at premises on Feeders 5–13 that received the affected voltage magnitude but possessed neither conventional demand-responsive DRUs (Section 13.2) nor the voltage-responsive ones (Section 13.4). Therefore, any impact on these premises might be attributable solely to the passive impact from short-term voltage reduction on premises electric loads. The regression model fit average premises power to ambient temperature (according to weather station D3057 in Milton-Freewater) by month, hour of day, and day of week.

The comparison-baseline approach was not used to evaluate the performance of these premises.

Increases in premises consumption were identified while the voltage was reduced, for the hour after the voltage was restored, and through the days on which event had occurred, just as had been found when using feeder load data. According to analysis using the modeled baseline, each premises consumed 73 ± 8 W *more* while the voltage remained reduced. The additional consumption remained similar at 70 ± 20 W during the hour after voltage had been restored to normal. The premises consumed 31 ± 3 W more throughout event days than they did on days that the voltage had not been reduced.

Project analysts had expected to observe a reduction in consumption for distribution feeders and at premises, as is normally the case for static CVR that is applied over long time periods. This expectation could not be confirmed. Quite the opposite appeared to be the case for short, dynamic voltage reductions on these Milton-Freewater feeders.

A short-term reduction in voltage could conceivably increase overall electric load through the interplay of load types and distribution line inefficiencies. The project has reservations confirming this result, however, because of the potentially confounding impacts that were encountered and that could be only partially mitigated. But the impacts of the coincident DRU curtailments, for example, would be predicted to have reduced, not increased, the apparent change in load.

The increase being reported is on the order of 2% of the average load on the five feeders, and a little less than 4% of an average premises load. These percentages are of a reasonable magnitude, but their sign is wrong. Upon inspecting the power data near in time to where voltage had been reduced, no “notch” could be observed among the noisy distribution and premises data. Milton-Freewater disputes this finding, saying that they often observe their load to decrease immediately as feeder voltages are reduced. The discrepancies between the findings in this section that are based on the project’s data analysis and this feedback from the utility based on their real-time observations remain unresolved.

Project analysis was halted at this point. It did not make sense to further compile benefits after the project’s analysis could find no net reduction in load during the system’s events. We will try to revisit this analysis later to determine the sources of the contradictory findings.

13.4 Voltage-Responsive, Grid-Friendly DRUs

The City of Milton-Freewater allowed about 100 of their new water heater DRUs to be made responsive to voltage reduction rather than otherwise communicated to via demand-response signals. This is a technology that had been described in (Hammerstrom 2010) as “augmented” CVR. The principle is that devices like water heaters may autonomously sense voltage-reduction events and interpret these events as requests for DR curtailment. In this case, the City of Milton-Freewater worked with vendor Aclara to configure their DRUs to recognize and respond to the 4.5% voltage reductions that already were occurring on Feeders 7–10 as part of the city’s dynamic voltage-reduction system (Section 13.3). The Aclara DRUs already featured an under-voltage response capability that could be modified for this purpose (Aclara 2012).

As for the previous two transactive asset systems at the City of Milton-Freewater that were discussed in Sections 13.2 and 13.3, curtailment of the voltage-responsive water heaters could help the city avoid demand charges from BPA if the curtailments were made to reliably coincide with peak utility hours each month. The city limited the number of curtailments and their durations on DRU water heaters so that its customers would not be inconvenienced. City staff said that they probably would have conducted more and longer reduced-voltage events on Feeders 5-13 had the voltage-responsive water heaters not been responsive to the voltage reduction. This is a lesson learned for this technology.

The stimulus for these voltage-responsive water heater DRUs is the same as that for the dynamic voltage management asset system (Section 13.3). Voltage-responsive water heaters might be simpler and more cost effective to deploy than those that require explicit DR communications, because they need no external communication infrastructure or its constantly evolving communication protocols. The water heater controllers sense when voltage has been reduced and curtail their loads. The water heater is returned to its normal operation after voltage has been returned to its normal level. Additional features can be added to the autonomous controllers to tailor their responses.

The annualized cost of this asset system was estimated from the actual cost of the DRUs and their installation, plus one-third of the costs incurred while establishing the local transactive system at the site and automating the city's responses to the transactive system. See Table 13.6, which summarizes the annualized system costs.

Table 13.6. Costs of the Milton-Freewater Voltage-Responsive DRU Water Heaters

	Shared Usage of Component (%)	Annualized Component Cost ($K)	Allocated Annual Component Cost ($K)
Water Heater DRUs	100	9.9	9.9
Transactive Node	33	9.8	3.2
Administrative (management and record keeping labor)	50	6.3	3.1
Outreach and Education	33	2.2	0.7
Total Annualized Asset Cost			**$17.0K**

13.4.1 Characterization of the Voltage-Responsive Water Heater System

The discussion of voltage-responsive water heater events is necessarily the same as that above concerning the voltage management system on Feeders 5–13 (i.e., Section 13.2.1). Recall that the times of reported events were found to be inaccurate. The project elected to infer the events from reductions of distribution voltage that were observed in the data supplied by Milton-Freewater.

Milton-Freewater informed the project that they might have conducted longer voltage-reduction events on Feeders 7–10 if the voltage-responsive water heaters had not been installed there. They feared inconveniencing the water heater owners if the voltage remained reduced for more than a few hours.

Milton-Freewater began to define a population of premises having voltage-responsive water heaters in June 2012. From then until the end of August 2014, the city maintained about 152 premises, on average, in this test group. There were briefly as many as 158 participating premises. Raw meter data was collected by the city's Aclara TWACS system from these premises at 15-minute intervals. The project calculated average per-premises power consumption of this test group and compared the consumption time series against two baselines.

The city worked with the project to establish a control population of premises that also were supplied by Feeders 7–10, but which did not have voltage-responsive water heaters or any of the city's other premises asset systems installed. The control group experiences the same voltage reductions as does the test group. The control group peaked at 310 participating premises and averaged 245 throughout the project's data collection period.

13.4.2 Voltage-Responsive Water Heater System Performance

The project analyzed premises data to see whether it could confirm an effect from the curtailment of the voltage-responsive water heaters. The test group was compared with a normalized baseline that was based on the control group (Section 13.4.1) and with another baseline, based on linear regression. As before, the corresponding baselines will be referred to as the *controlled* and *modeled* baselines.

Like the test premises, the control premises were supplied by Milton-Freewater Feeders 7–10, but they did not have voltage-responsive water heaters. The average per-premises power of this control group was scaled each month to have the same average and standard deviation as the test group. Small variations in hourly load profile were still observed between the two populations, so the control group's time series was further globally corrected for any differences from the test group's hourly consumption.

Another baseline time series was generated using linear regression to emulate the average power consumption of test premises had they not had voltage-responsive water heaters. Analysts used R software to generate this regression model. The test group data was fit to ambient temperature (weather station D3057 in Milton-Freewater) by month, day of week, and hour of day to create the modeled baseline.

Project analysts compared the test-group premises' power with the two baselines using an independent Student's t-test. The reported statistical results are the monthly and project averages during inferred curtailment events, during the rebound hour following the events, and during entire event days. The error bars that will be shown in these figures represent standard error (heavy bars) and 95% confidence intervals (lighter, dashed bars).

Theoretically, each water heater that becomes curtailed should reduce the utility's total load by 0.2−0.8 kW, depending on the time of day. Therefore, the set of 100 water heaters should reduce city electric load by 20–80 kW while they remained curtailed. The impact from these water heaters on the transactive system should have been estimated by a transactive function that predicted the impact of dynamic voltage management (Section 13.3) along with the other impacts that would accompany voltage reduction on Feeders 5–13. This special case of the CVR toolkit function (i.e., the one that included the predicted impact from these voltage-responsive water heaters) was never implemented during the project, so the predicted change in load was not incorporated into the site's transactive power feedback prediction.

While the voltage was in its reduced state, the test group premises consumed 144 ± 6 W less power or 200 ± 5 W less power, according to the modeled and controlled baselines, respectively. The calculated results using the two baselines are shown in Figure 13.28 to be tightly clustered around these values except for several months that exhibited greater variability. The averaged result from using the two baselines is a reduction of 170 W. Because the two methods generated somewhat different results, the project will report the standard deviation of the results from the two methods, ± 40 W, as the variability of this result. The voltage-responsive water heaters were reliably and consistently curtailed by the reduction in distribution voltage.

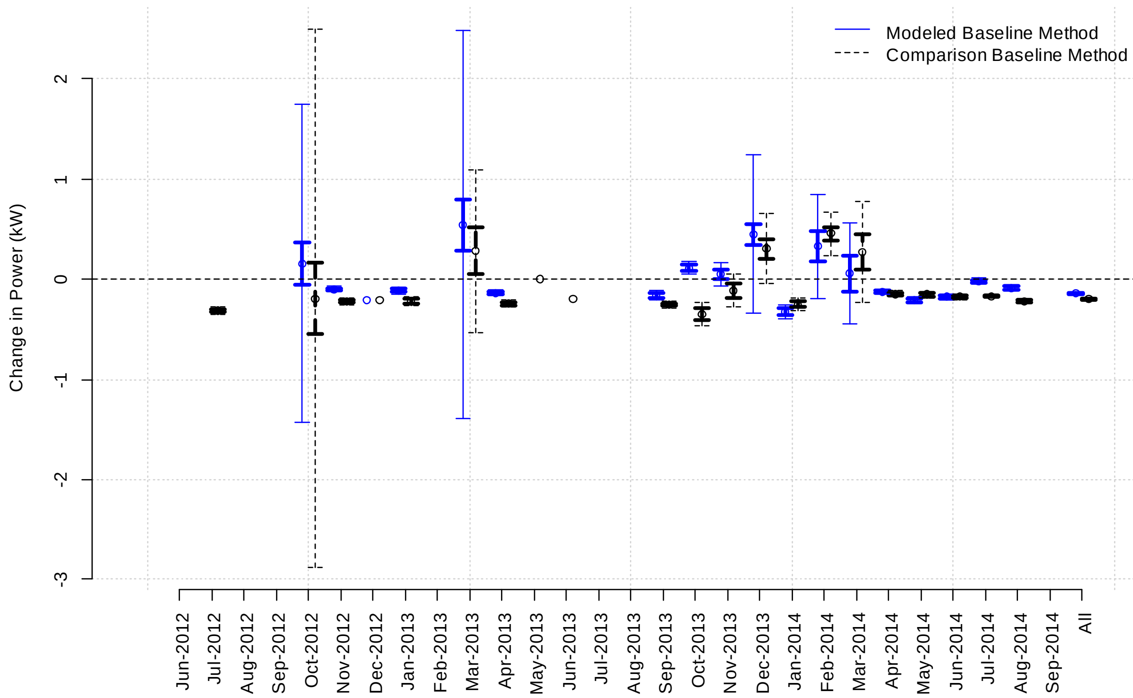


Figure 13.28. Power Curtailed per Voltage-Responsive DRU Premises by Month and for the Entire Project using the Modeled (blue) and Controlled (black dashes) Baseline

A strong rebound effect occurred at these test premises in the hours immediately following the reductions in feeder voltage. The spike in average premises power consumption was almost always evident by inspection of the time series. Comparison with the modeled baseline indicated an increase of 330 ± 20 W per premises during rebound hours. The controlled baseline suggested a similar increase of 290 ± 20 W. If the results of these two methods are averaged, the project should report a rebound of 310 ± 30 W, where the variability is the standard deviation of the two results from the two methods.

The month-by-month measurements were quite consistent, as is shown in Figure 13.29. It is clear that the rebound effect is strong for water heaters controlled in bulk by this method. Control logic could be added to mitigate the strong rebound at the device level.

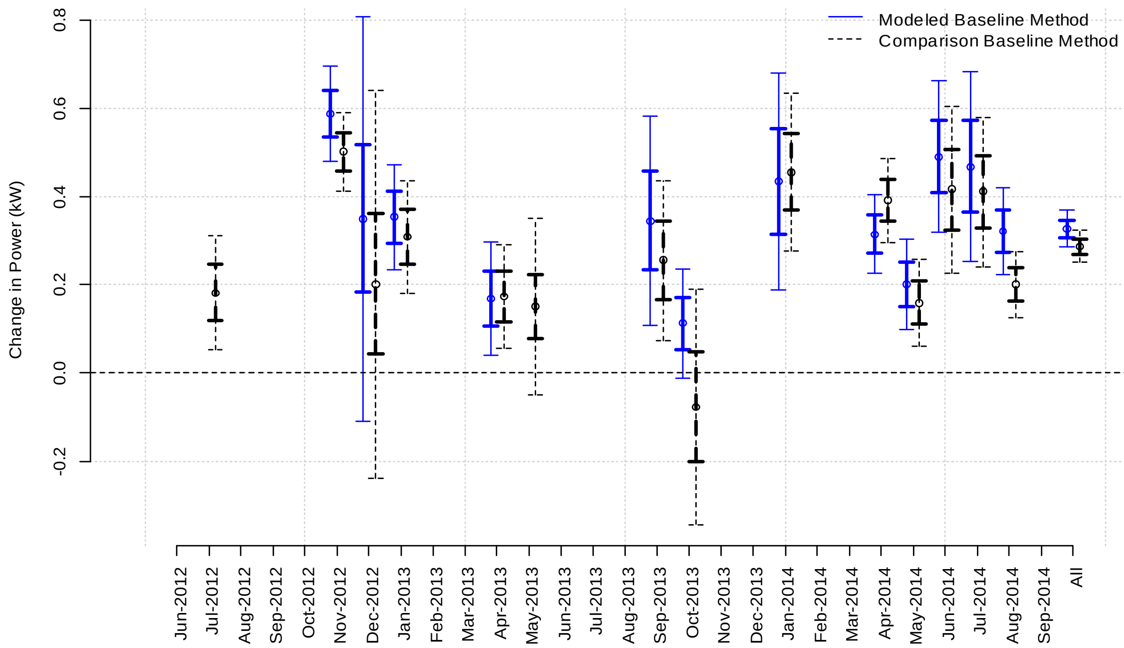


Figure 13.29. Average Rebound Power of the Premises that Had Voltage-Responsive Water Heaters in the Hours following Events using the Modeled (blue) and Controlled (black dashes) Baselines

The rebound spike is often a strong time marker location in the time series as is evident in Figure 13.30, which shows the average test group per-premises power time series (blue) and its controlled (green) and modeled (pink) baselines for an extended time period before and after an August 27, 2014 event. The event period has been shaded yellow, and the rebound hour has been shaded gray. A rebound spike is clearly evident during the rebound hour.

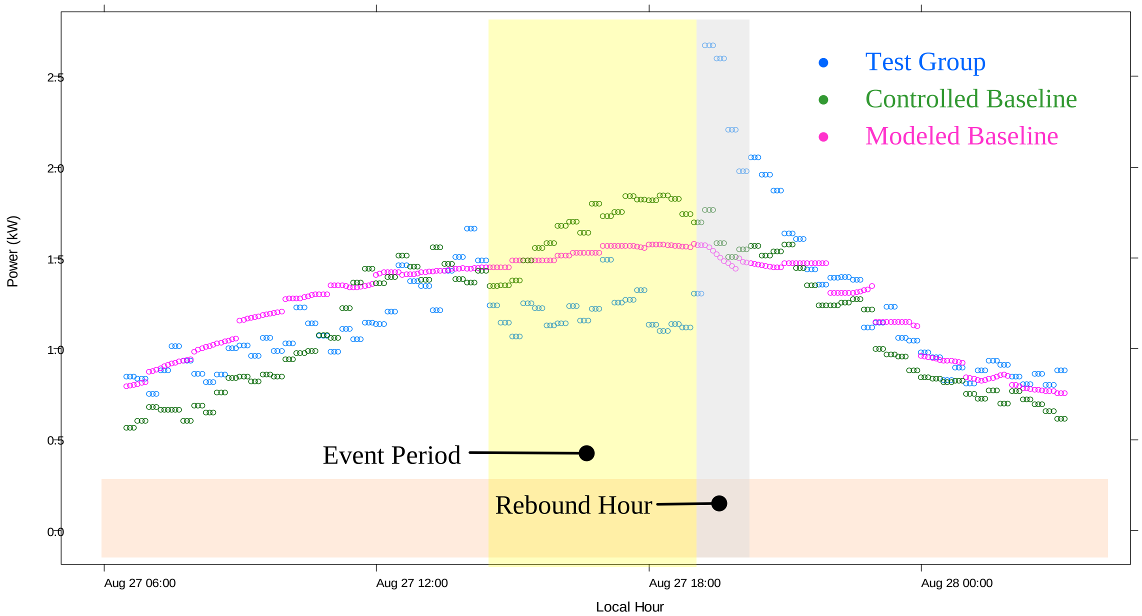


Figure 13.30. Test Group Per-Premises Power (blue) and its Controlled (green) and Modeled (pink) Baselines on August 27, 2014. The event period (shaded yellow) and rebound hour following the event (shaded gray) are also shown.

For some undetermined reason, the rebound spike in the time series was observed sometimes to occur after the rebound hour (not shown). That is, the rebound spike occurred more than an hour after the voltage had been returned to its normal level. Consequently, the rebound impact might be even larger than what is being reported by the project. There might have occurred additional logic in the autonomous responses of the water heaters that is unknown to the project. Alternatively, a one-hour timing shift might have occurred occasionally in data collection processes between the reported distribution voltage and premises power time series. The project has not been able to determine the precise cause.

Regardless, large rebound impacts are potentially problematic for this and other curtailment programs that engage, then disengage, large electric load populations. As the utility strives to reduce a load peak, it might inadvertently create another as the curtailments are halted. The magnitude of the rebound may be reduced or eliminated with additional logic at the controllers that spreads the release of the event over time for the population.

The two baseline approaches yielded small, contradictory results concerning the average change in power consumption of the test group over days that voltage had been reduced. See Figure 13.31. The result from the comparison-baseline approach might be more trusted because it explicitly excluded entire event days during its normalization, while the model excluded only event and rebound periods. Regardless, the project reports that virtually no net impact was measured throughout event days for the voltage-responsive water heater system.

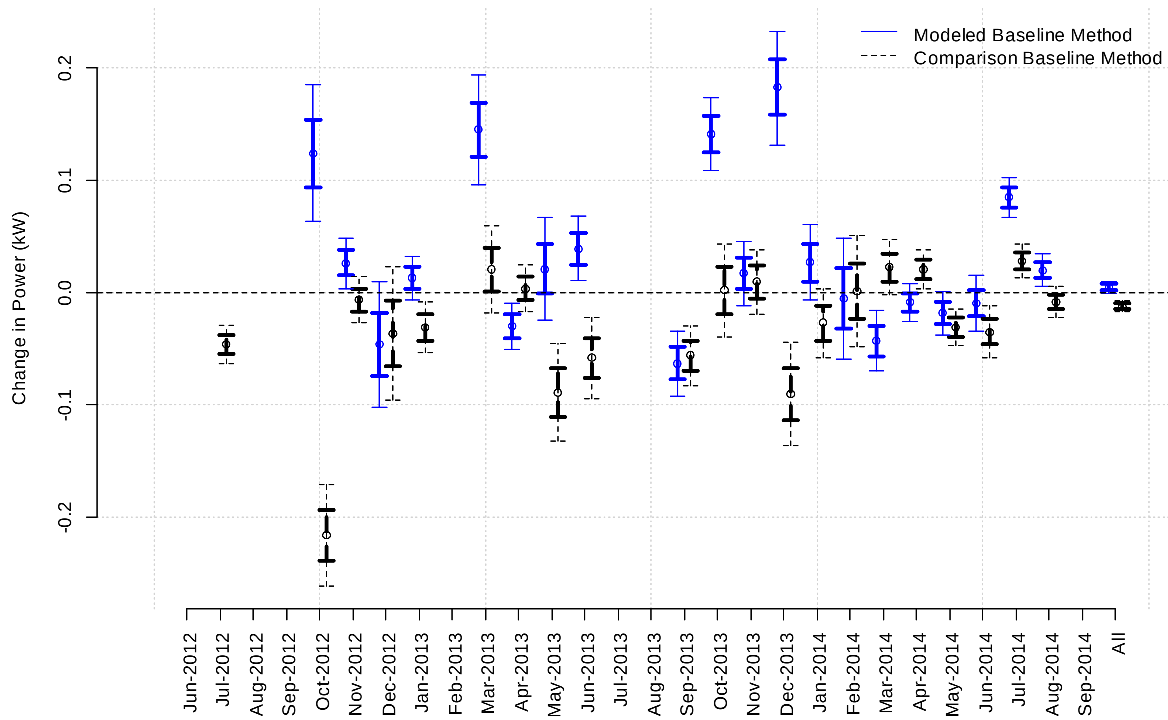


Figure 13.31. Change in Average Per-Premises Power Consumption on Days that Voltage had been Reduced Using the Modeled (blue) and Controlled (black dashes) Baselines

Based on the analyzed effect of voltage-responsive water heater events on system load, Table 13.7 estimates the total impact on the city's load by calendar month. The impact is separately assessed for HLH and LLH hours so that BPA's load-shaping rates (Appendix C) may be used to estimate the value of the unneeded energy. If the city were to continue engaging this set of voltage-responsive water heaters as it did during the PNWSGD, it would purchase about 5.5 MWh less energy from BPA each year worth about $162.

Much of the water heaters' curtailment energy is simply deferred to be used later after the event has concluded. As was discussed in the previous section, the project was not able to determine with confidence how much of the energy was deferred and how much was truly conserved.

Table 13.7. Estimated Supply Energy and the Value of Supply Energy Displaced each Calendar Month by Voltage Responsive Water Heater Events

	HLH		LLH		Total	
	(kWh)[a]	($)[b]	(kWh)[a]	($)[b]	(kWh)[a]	($)[b]
Jan	−943 ± 87	−35.6 ± 3.3	−15 ± 9	−0.5 ± 0.3	−958 ± 87	−36.1 ± 3.3
Feb	−400 ± 36	−14.8 ± 1.3	−21 ± 7	−0.6 ± 0.2	−421 ± 37	−15.4 ± 1.3
Mar	−570 ± 39	−17.2 ± 1.2	−137 ± 22	−3.4 ± 0.6	−707 ± 45	−20.7 ± 1.3
Apr	−449 ± 56	−11.6 ± 1.4	−25 ± 23	−0.5 ± 0.5	−474 ± 61	−12.1 ± 1.5
May	−626 ± 67	−13.1 ± 1.4	−24 ± 11	−0.3 ± 0.1	−650 ± 68	−13.5 ± 1.4
Jun	−1,000 ± 110	−22.7 ± 2.5	−206 ± 50	−3.0 ± 0.7	−1,210 ± 121	−25.7 ± 2.6
Jul	−72 ± 66	−2.2 ± 2.0	−12 ± 6	−0.3 ± 0.1	−84 ± 66	−2.5 ± 2.0
Aug	−231 ± 33	−7.8 ± 1.1	−9 ± 14	−0.2 ± 0.4	−240 ± 36	−8.1 ± 1.2
Sep	−9 ± 26	−0.3 ± 0.9	−16 ± 17	−0.4 ± 0.5	−25 ± 31	−0.7 ± 1.0
Oct	−4 ± 9	−0.1 ± 0.3	11 ± 10	0.3 ± 0.3	7 ± 13	0.2 ± 0.4
Nov	−355 ± 32	−12.6 ± 1.1	−41 ± 13	−1.3 ± 0.4	−396 ± 35	−13.9 ± 1.2
Dec	−284 ± 43	−11.0 ± 1.7	−75 ± 17	−2.5 ± 0.6	−359 ± 46	−13.5± 1.8
Totals	**−4,940 ± 200**	**−149.2 ± 5.9**	**−570 ± 70**	**−12.8 ± 1.5**	**−5,520 ± 210**	**−162.0 ± 6.1**

(a) Negative energy values in these columns mean that load was reduced during events, according to the project's analysis methods and data.

(b) Negative dollar amounts in these columns mean that the utility's net cost of wholesale energy decreased during events, according to the project's analysis. Dollar amounts have been rounded to the nearest dime.

Table 13.8 shows the calculated impacts that the voltage responsive water heaters each calendar month and for an entire year. A preliminary table was first generated from the devices' performance to compile the average change in load during events by calendar month and individual HLH hours. Because there were often multiple event periods in each calendar month and HLH hour, an average change in power and standard error could be calculated for each hour and month. Next, a list of the city's historical peak hours was compared with this table. The set of peak hours each calendar month determined the weighting the hours and their impacts would have in the statistical analysis. The second column of Table 13.8 is the result of that assessment. It predicts the change in peak-hour energy each month based on the system's demonstrated performance. The values are somewhat optimistic because the method presumes that the city will accurately engage the system during the peak hours.

The average impact on the demand during HLH hours was calculated by summing the energy during the HLH hours in a month and dividing that energy by the number of HLH hours in the month.

Finally, the differences between the peak-hour demand impacts and the aHLH impacts were multiplied by the corresponding monthly BPA demand rates (Appendix C). Milton-Freewater would reduce its demand charges by about $1,620 ± 260 each year if it were to continue operating the voltage-responsive water heaters as demonstrated and if it were to accurately engage the system during peak hours each month.

Table 13.8. Estimated Impact of Milton-Freewater's Voltage-Responsive Water Heaters on the Utility's Demand Charges

	Δ Demand (kW)	Δ aHLH (kWh/h)	Δ Demand Charges ($)
Jan	−56 ± 7	−2.3 ± 1.4	−600 ± 80
Feb	−28 ± 9	−1.04 ± 0.33	−294 ± 98
Mar	1 ± 5	−1.32 ± 0.21	13 ± 45
Apr	−6 ± 9	−1.1 ± 1.0	−37 ± 69
May	−4 ± 23	−1.56 ± 0.68	−15 ± 143
Jun	−26 ± 8	−2.41 ± 0.58	−159 ± 54
Jul	−6 ± 6	−0.18 ± 0.08	−52 ± 54
Aug	−4 ± 6	−0.54 ± 0.82	−35 ± 61
Sep	5 ± 4	−0.02 ± 0.02	50 ± 40
Oct	9 ± 2	−0.01 ± 0.01	84 ± 19
Nov	−5 ± 2	−0.89 ± 0.28	−43 ± 21
Dec	−47 ± 10	−0.71 ± 0.16	−531 ± 115
Total			**−1,620 ± 260**

(a) Negative demand amounts in these columns mean that the impact during events reduced the determinant component during events, according to the project's methods and data.

(b) A negative dollar amount in this column means that the utility's demand charges were analyzed to have decreased by the given dollar amount.

13.5 Conservation from CVR on Feeders 1–4

The voltage management system on site Feeders 1–4 is similar to that on Feeders 5–13 (Section 13.3), except that more traditional, static CVR was used on Feeders 1–4. The system on Feeders 1–4 was not made responsive to the project's transactive system and its incentives. Every other week, the City of Milton-Freewater staff reduced the distribution feeder voltages for Feeders 1–4 by one transformer tap—about 1.5%. The change in voltage was performed at the same time each Wednesday during the term of the project. The project observed total feeder power on distribution Feeders 1–4 and compared the power between periods when the voltage was reduced and when it was normal.

The city wished to investigate CVR as a means to conserve electricity. However, based on discussions with city staff, the benefit of this energy conservation to the city is unclear. The city's electricity customers consume less while voltage is reduced, meaning that its revenues are reduced and the city purchases less energy from its supplier. The benefit to the city is unclear.

The City of Milton-Freewater and the project jointly estimated the annualized system costs. These costs included the costs of four Metrum model L+G 25 tap-changing transformers, labor and software to install the system and make it remotely responsive by the city, and approximately one-third of the costs of premises meters and meter systems. Refer to Table 13.9 for the summarized annual system costs.

Table 13.9. Costs of the Milton-Freewater CVR System on Feeders 1–4

	Shared Usage of Component (%)	Annualized Component Cost ($K)	Allocated Annual Component Cost ($K)
Residential and Commercial Premises Meter System	33	270.3	90.0
Programming for Automatic Control of Voltage SCADA	50	11.0	5.5
End-of-Line Voltage Sensing	33	7.3	2.4
Total Annualized Asset Cost			**$97.9K**

Refer back to the layout of the City of Milton-Freewater asset systems in Figure 13.1 to comprehend the relationships between this asset system and the city's circuits and its other asset systems that were being tested during the PNWSGD.

13.5.1 Characterization of the CVR System Responses

The project received distribution voltage readings every 15 minutes and averaged these reading for Feeders 1–4. Figure 13.32 demonstrates the control of averaged per-unit distribution voltage on CVR Feeders 1–4 during the project duration. The voltage clearly changes on a weekly basis. Additionally, the voltage changes correspond accurately with the CVR conditions that the City of Milton-Freewater reported to the project. The colors refer to periods when the city had reported normal operation (red) and reduced-voltage operation while CVR was engaged (blue).

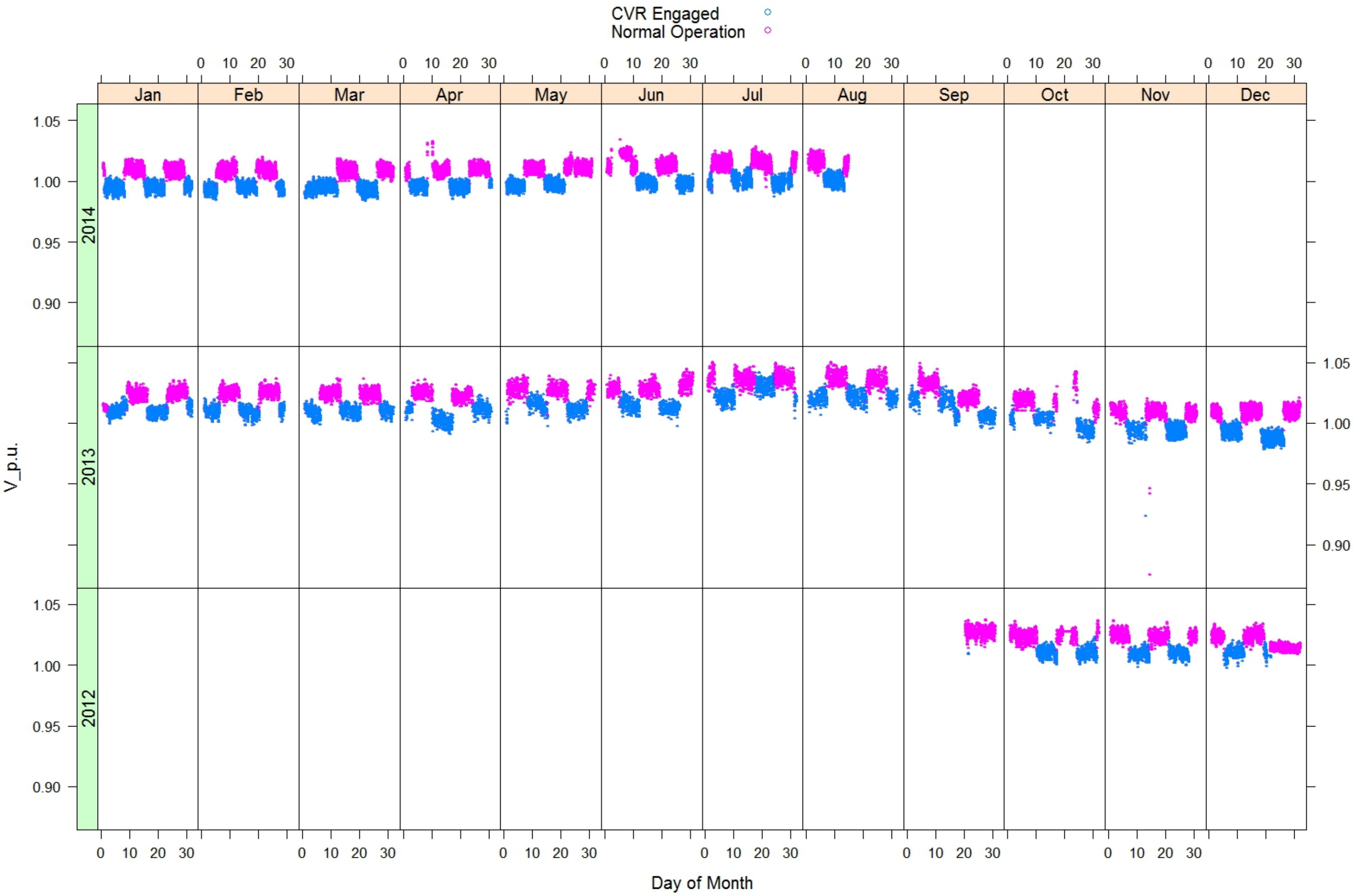


Figure 13.32. Average Per-Unit Voltage on CVR Feeders 1–4 by Project Year, Month, and CVR Status

The nominal voltage was unusually large during parts of October 2013, May 2014, and June 2014. A nominal voltage that is too large might result in an overstatement of the impact of CVR during these months. In contrast, the nominal voltage might be too low the last week of December 2012 and into January 2013, which would have the opposite effect on the analysis.

The CVR voltage reduction appears to have been too small during the third week of July 2013. The effect of this small voltage reduction would be an understatement of the CVR impact that month. While data collection began late in September 2012, CVR was not truly active, and analysis is probably not meaningful for that September.

Figure 13.33 shows the observed distribution voltage on Feeders 1–4 for each project month. As predicted, a voltage reduction averaging 1.52% accompanies a single tap-setting change. The months December 2012, July 2013, October 2013, and December 2013 exhibited voltage changes that were somewhat smaller or larger than anticipated. Long-term changes in the target voltage setting are evident in Figure 13.33 that were not easily seen in Figure 13.32. Perhaps the distribution system was operated one tap setting higher during the summer of 2013 and was reduced two full tap settings in October 2013. These management strategies affected both the "normal" and reduced-voltage settings each month. In fact, the "reduced" voltage setting from the first half of the demonstration became the "normal" setting during the second half.

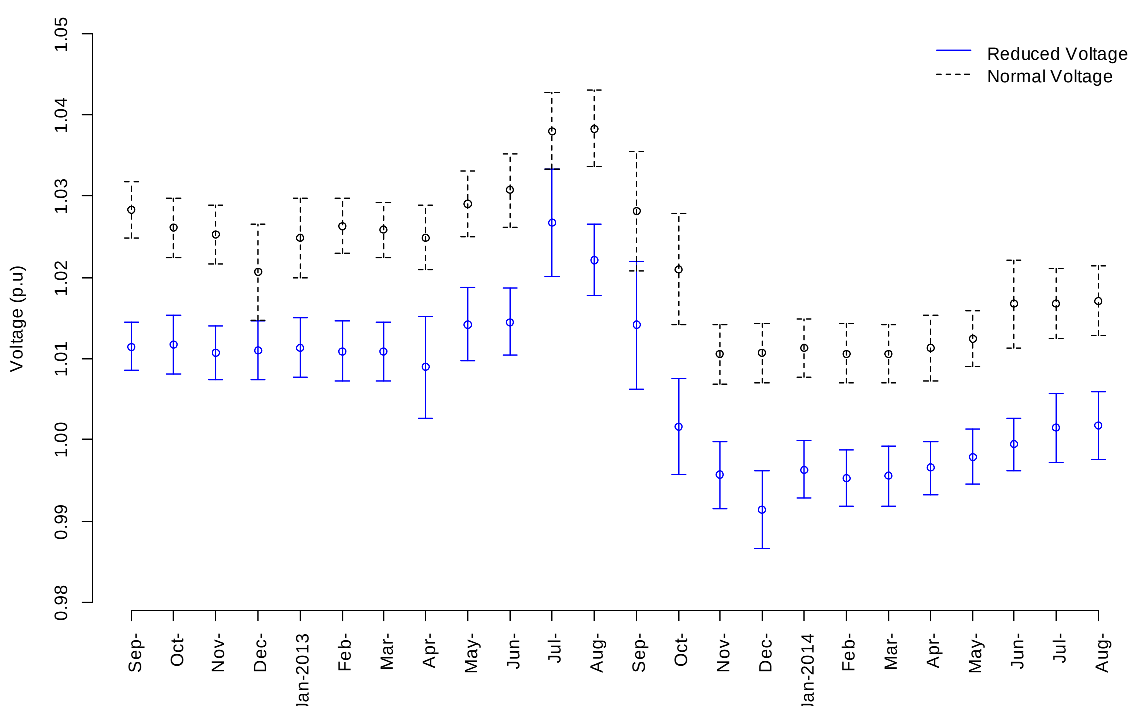


Figure 13.33. Observed CVR Change in Per-Unit Voltage by Project Month when Voltage is Reduced (blue) and Normal (black dashes). The bars represent standard deviations during the months.

13.5.2 Conservation-Voltage-Regulation System Performance

The project analyzed the data provided from the City of Milton-Freewater to determine the impact on distribution power consumption of reducing the distribution voltage by 1.5%.

The project received distribution feeder power data with 15-minute data intervals. There were two important sets of aggregated feeder power data used to analyze the CVR impact. The sum of the power on Feeders 5–13, which were not subjected to the same voltage management, was normalized and compared against total power on Feeders 1–4, where CVR was being practiced. These are two of the aggregated power time series that were shown in Figure 13.3.

A simple normalization approach was used to scale the sum power from Feeders 5–13 to have the same mean and standard deviation month by month as that of the sum power of Feeders 1–4 when the voltage on Feeders 1–4 was normal. The scaled time series was used to infer what the CVR feeders' power might have been if the feeders had remained at their nominal voltage levels.

This method should be compared and contrasted with other methods discussed in the literature. In RTF CVR Subcommittee (2012), an alternate day protocol involving CVR being on or off on alternate days is proposed along with a temperature normalization regression method. The protocol used in this project is alternate week protocol. A regression is performed to relate average hourly kW to hourly heating and cooling degree days and average hourly voltage. In this project, the dependence of the Feeders 1−4 power on non-measured variables is implicitly accounted for through its relationship with Feeders 5−13. The resulting *change* in power (rather than absolute power) can now be related to *change* in voltage and temperature. Such a detailed analysis is left for future work. In this project an overall voltage reduction and power reduction during analysis period is used in determining CVR factor.

Another baseline-comparison time series was created similarly to predict what the CVR feeders' power would have been if they had remained at their *reduced*-voltage levels. The advantage of using this baseline was that a comparison could then be made throughout each month, not limited to times that the voltage had been reduced. This reduces biases between the test and control feeders because any biases between the compared feeders are added one week, then subtracted the next. Furthermore, this baseline approach is unlikely to have been adversely affected by the changing target voltages that were evident from Figure 13.33. The two baselines serve as checks on one another.

Because transactive DRUs (see Section 13.2) resided in similar relative numbers on the experimental and control feeders (Feeders 1–4 and 5–13, respectively) and the DRU curtailment events were short and infrequent, the DRU events were mostly ignored. However, care was taken during analysis to avoid potentially confounding effects from the dynamic transactive voltage management on Feeders 5–13 (Section 13.3) because these events were more frequent and directly impacted the comparison baseline. Both control and experimental data were removed any time the dynamic transactive voltage management (Section 13.3) events were active.

The city occasionally reconfigures its distribution switches, and one or more feeders' demand may be then supplied from different feeders' transformers. If any of the electric load on Feeders 1–4 becomes supplied from Feeder 5–13 transformers, or vice versa, then the aggregated power measurements from these aggregate groups become tainted. The city listed for the project time periods when their 13 feeders were abnormally configured. These abnormal circuit conditions were found to occur infrequently, so the project elected to simply not use data when the circuit conditions were abnormal.

Figure 13.34 exemplifies the aggregated Feeder 1–4 power (blue) and the two baseline time series that represent normal voltage (red) and reduced-voltage (green) conditions for several project months in 2014. The baseline powers are similar to the experimental feeders' power. However, close comparison of the series revealed some residuals for differences by time of day.

Data is missing where the circuit configuration was abnormal and where potentially confounding voltage management events occurred on Feeders 5–13. Differences between the experimental and baseline time series are difficult to see amidst normal noise in feeder power.

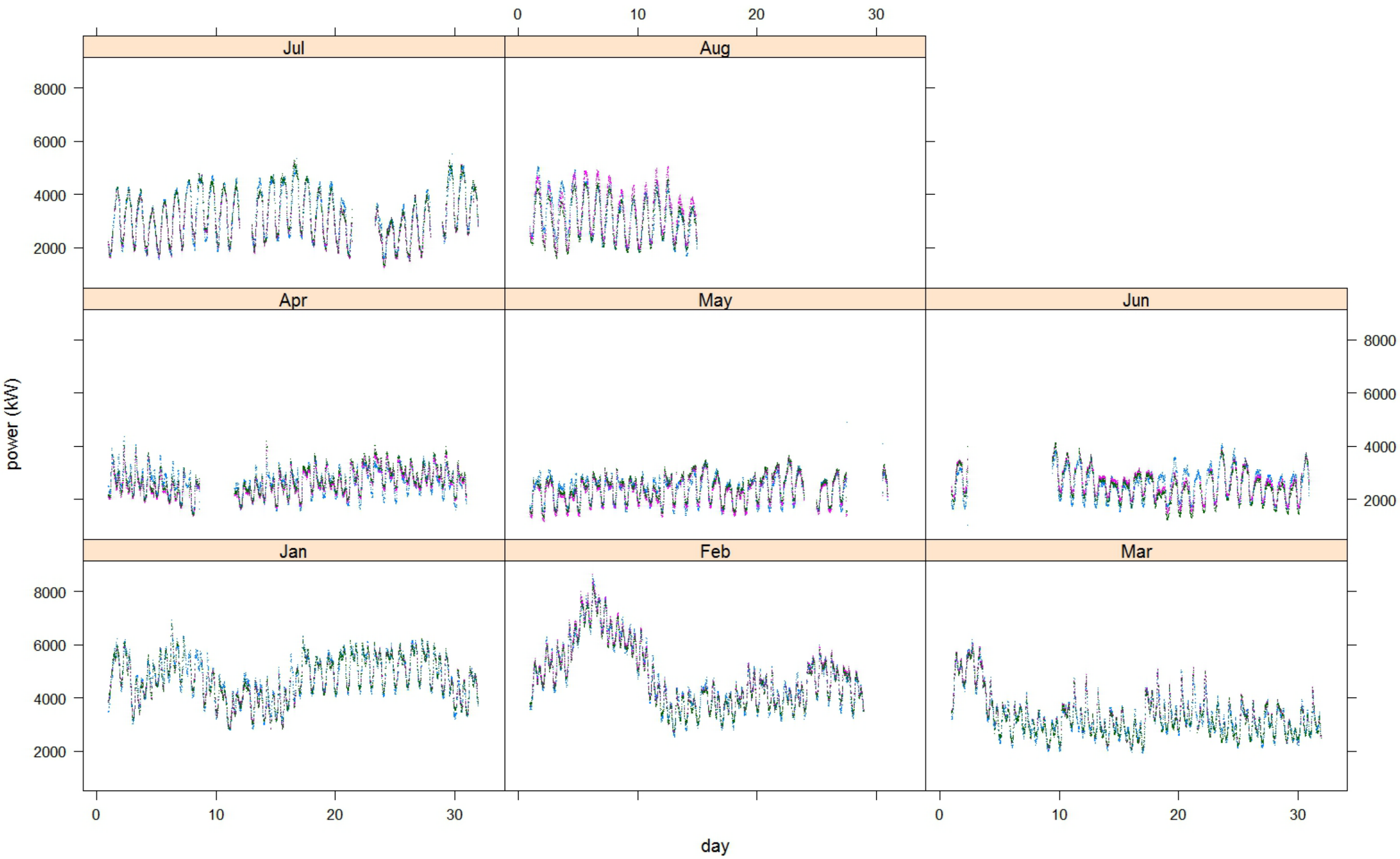


Figure 13.34. Example Aggregated Experimental and Baseline Feeder Power Data from 2014 that was Used to Analyze the Impact of CVR at Milton-Freewater

The change in power attributable to the practice of CVR each month on Feeders 1–4 is shown in Figure 13.35. The x-axis is the set of months in which data was collected. On the far right is an aggregate result for all project months. Each marker is an average difference in power between reduced-voltage operation and a baseline that represents operation under the normal voltage. Two methods of comparison were employed. The blue markers are the difference between the Feeders 1–4 measurements under reduced voltage and the baseline that represents normal operation. The dashed black markers are the difference between the Feeders 1–4 measurements while voltage is normal and the baseline that represents reduced-voltage operation. The two normalization approaches are found to yield consistent results each month regardless of which baseline was used for the normalization. The arrow lengths estimate a standard-error bound on the monthly averaged differences. The extended bars indicate estimated 95% confidence intervals based on each month's data.

Most, but not all, the monthly results show a reduction in power consumption. The project reports an overall power reduction of 26 ± 2 kW, using both of the controlled baselines and all available project data. Note that the magnitude of power reduction during CVR is a function of the voltage change. Based on the average load on Feeders 1–4 (3.25 MW), this is a 0.80% average power reduction on these feeders when CVR is engaged. The CVR factor is 0.53. This calculation has used a constant voltage change even though the voltage change was shown during analysis to have differed somewhat throughout the project.

The City of Milton-Freewater had expected a substantially greater impact from this asset system.

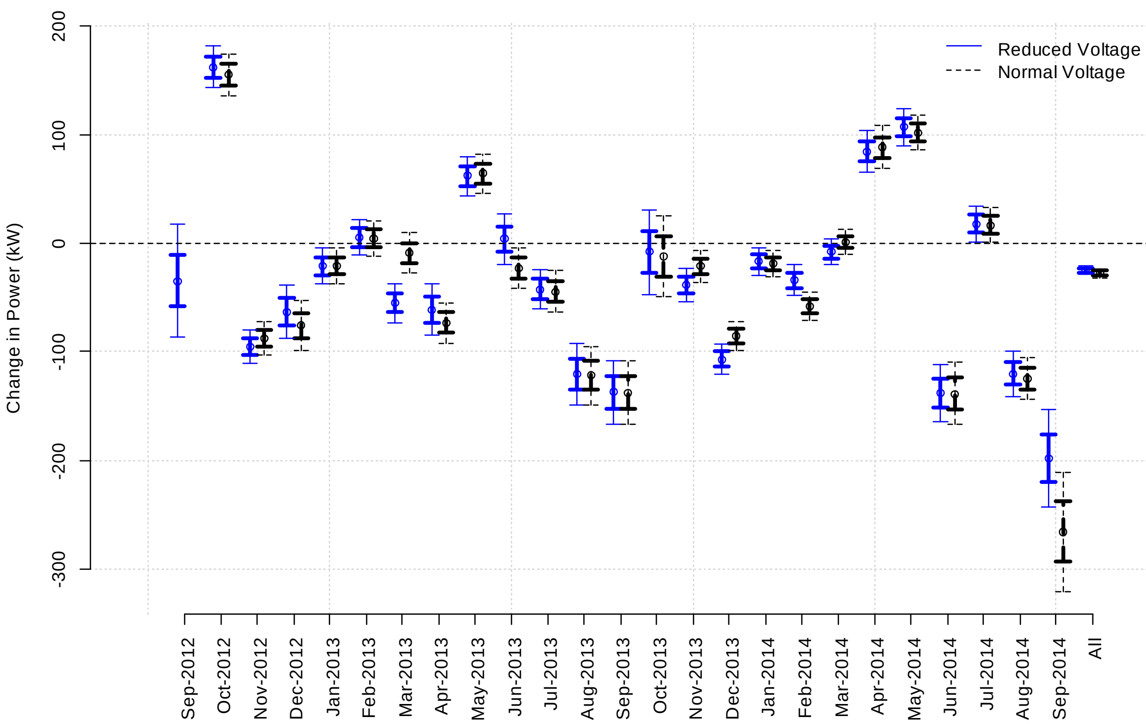


Figure 13.35. Change in Total Power on Feeders 1–4 Attributable to CVR each Project Month Using Two Baselines Suited for Comparisons while Voltage is Reduced (blue) and Normal (black dashed).

In Figure 13.36, the same data has been parsed by local hour of day and by whether the hour occurs on a weekday (blue) or weekend (dashed black). The impacts for weekday hours are shown to vary less than for the weekend ones. Weekend Hours 8, 9 and 10 show an interesting *increase* in power consumption while voltage is reduced. Otherwise, consumption is reduced by CVR more on weekend hours than on weekday hours. This is plausible given that the city's electric loads during weekdays and weekend days may be quite different.

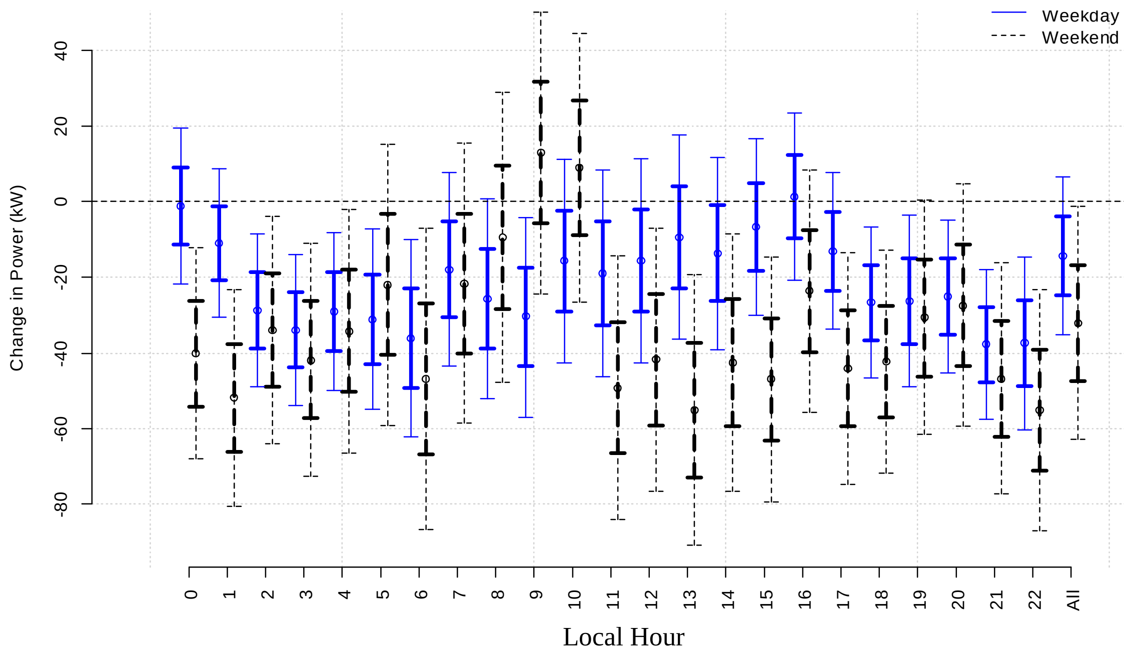


Figure 13.36. Total Change in Power Attributable to CVR on Feeders 1–4 By Hour (Pacific Time) and Weekday (blue) and Weekend (black dashes)

Table 13.10 summarizes the cumulative impact that the practice of CVR would have on Feeders 1–4 if the voltage were to remain reduced by 1.5%, the voltage reduction that was used during the demonstration. The results are calculated for each calendar month and for an entire year. The calculations were separately performed for HLH and LLH hours so that BPA's load-shaping rates (Appendix C) could be used to estimate the monetary value of the avoided wholesale energy purchases. Based on the project's analysis methods and data, Milton-Freewater would avoid buying 99.3 MWh each year, which is presently worth about $3,520 ± 240 to Milton-Freewater according to BPA load-shaping rates.

The utility, however, also loses the opportunity to sell sale much of this energy to its customers, which would be worth about $4,970 to Milton-Freewater at $0.05 per kWh.

Table 13.10. Projected Supply Energy and the Value of Supply Energy that Would be Displaced by CVR on Feeders 1–4. Calculated impacts presume that voltage remained reduced on Feeders 1–4, not just on alternating weeks.

	HLH		LLH		Total	
	(MWh)	($)	(MWh)	($)	(MWh)	($)
Jan	−2.2 ± 1.6	−83 ± 60	−5.7 ± 1.2	−175 ± 37	−7.9 ± 2.0	−258 ± 70
Feb	−1.0 ± 1.5	−37 ± 55	−3.9 ± 1.0	−119 ± 31	−4.9 ± 1.8	−156 ± 63
Mar	−5.3 ± 1.7	−160 ± 51	−7.0 ± 1.5	−176 ± 38	−12.3 ± 2.3	−336 ± 64
Apr	5.8 ± 2.1	149 ± 54	−2.8 ± 2.0	−56 ± 40	3.0 ± 2.9	93 ± 67
May	14.8 ± 1.7	311 ± 36	14.9 ± 1.5	195 ± 20	29.7 ± 2.3	506 ± 41
Jun	−19.3 ± 2.7	−439 ± 61	−5.5 ± 1.8	−80 ± 26	−24.8 ± 3.2	−519 ± 66
Jul	−1.4 ± 1.7	−43 ± 52	−2.7 ± 1.3	-66 ± 32	−4.1 ± 2.1	−109 ± 61
Aug	−26.9 ± 2.3	−914 ± 78	−11.5 ± 1.3	−312 ± 35	−38.4 ± 2.6	−1,226 ± 85
Sep	−22.2 ± 2.3	−747 ± 77	−13.1 ± 1.2	−365 ± 33	−35.3 ± 2.6	−1,112 ± 84
Oct	15.7 ± 2.5	496 ± 79	28.4 ± 2.4	779 ± 66	44.1 ± 3.5	1,280 ± 100
Nov	−14.8 ± 1.5	−526 ± 53	−7.9 ± 1.1	−247 ± 34	−22.7 ± 1.9	−773 ± 63
Dec	−9.7 ± 1.4	−377 ± 54	−16.0 ± 0.9	−532 ± 30	−25.7 ± 1.7	−909 ± 62
Totals	**−66.5 ± 6.8**	**−2,370 ± 210**	**−32.8 ± 5.2**	**−1,150 ± 130**	**−99.3 ± 8.6**	**−3,520 ± 240**

(a) Negative energy values in these columns mean that net load was decreased by the CVR according to the project's methods and data.

(b) Negative dollar values in these columns mean that CVR decreased the wholesale energy that the utility would have otherwise purchased according to the project's analysis.

The impact of the CVR system on the utility's demand charges has been estimated in Table 13.11. These estimates are "projected" in that they presume CVR was practiced on Feeders 1–4 throughout the year, not on alternate weeks. The second column projects the impact of CVR on the utility's demand during each calendar month's peak hour. This column was calculated by first preparing a preliminary table (not shown) of statistical impacts for each calendar month and its HLH hours. This preliminary table is much like the data that was plotted in Figure 13.36, except it is separately created for each calendar month and uses only HLH hours. Because there were multiple instances of each hour and month, both the average and standard error of the potential impact on the utility's demand could be calculated for each calendar month and HLH hour. Next, the utility's historical peak hours for each calendar month were used to determine an average impact for that month for coincident HLH hours. Each historical peak hour was presumed to have equal likelihood, and these sample hours were then used to weight the impacts from the individual coincident HLH hours.

The impact on average heavy load hour (aHLH) demand was estimated by averaging the impacts from all the aHLH hours in each calendar month.

Finally, the estimated impact on demand charges was estimated by multiplying the differences between the peak hour impacts and aHLH impacts by the corresponding months' BPA demand rates (Appendix C). The continuous practice of CVR on Feeders 1–4 would reduce the utility's demand charges by about $4,400 ± 1,500 per year.

Table 13.11. Projected Impact of CVR on the Utility's Demand Charges. Calculations presume the voltage is always reduced on Feeders 1–4.

	Δ Demand[a] (kW)	Δ aHLH[a] (kWh/h)	Δ Demand Charges[b] ($)
Jan	−62 +/- 31	−5 ± 1	−640 ± 350
Feb	−101 ± 37	−3 ± 1	−1,070 ± 400
Mar	−49 ± 38	−12 ± 3	−330 ± 340
Apr	1 ± 50	14 ± 10	−100 ± 390
May	89 ± 30	37 ± 4	322 ± 190
Jun	−81 ± 47	−46 ± 15	−240 ± 332
Jul	23 ± 28	−3 ± 2	230 ± 250
Aug	−129 ± 45	−62 ± 7	−670 ± 460
Sep	−271 ± 92	−56 ± 5	−2,140 ± 920
Oct	181 ± 45	36 ± 3	1,350 ± 420
Nov	−109 ± 27	−37 ± 5	−760 ± 290
Dec	−55 ± 30	−24 ± 1	−360 ± 340
Total			**−4,400 ± 1,500**

(a) Negative demand and average demand values in these columns mean that the demand was reduced by CVR according to the project's methods and data.

(b) Negative dollar values in this column mean that CVR is projected to reduce the utility's demand charges by this amount according to the project's analysis.

13.6 Conclusions and Lessons Learned

The City of Milton-Freewater tested four asset systems during the PNWSGD. An objective of the city was to control the responses of three of these systems to reduce its monthly demand charges. Toward this end, the city participated in the project's transactive system and established a demand-charges function that was to help engage the city's responsive assets whenever the city might be experiencing its monthly peak demand. The demand-charges function was established and was connected to the regional transactive system, but it never became fully configured and functional and therefore did not much help the city automate its efforts to reduce its demand charges.

One of the responsive systems was a set of about 800 DRUs attached to various 240-Volt premises loads like water heaters and air conditioners throughout the city. The switchable devices interacted with and could be communicated with via the existing TWACS system in Milton-Freewater. Two different classes of responses were established by the city. Some events were called at the times suggested by the project's transactive system; however, the city independently initiated additional events using features of its vendor's software, which conducted sequential engagements and disengagements of multiple DRU subgroups while automatically observing the magnitude of the city's demand. At one point, vendor software was found to have been preventing the DRUs from responding to the events that had been initiated by the transactive system. For this and other reasons the early performance of the system was poor, but the performance of the DRUs improved toward the end of the project period. The project calculated that, on average, each DRU had reduced its premises' load by about 100 W during all the project's DRU curtailment events. Toward the end of the project, the DRUs were consistently curtailing 270 W at each DRU location.

Milton-Freewater tested a dynamic voltage reduction that might be controlled to shape load and avoid demand charges. On nine of its 13 feeders, the city reduced the feeders' voltage by up to 4.5% (three taps) for hours at a time. The project looked for the system's impacts in the summed power from the five of affected feeders that had no voltage-responsive water heaters, another asset system tested by the city during the PNWSGD. The city's list of times when it was to have reduced the voltage in this way was found to be inaccurate when it was compared with feeder voltage data. Therefore, the project inferred event periods from its observations of feeder data. While the city contends that they can easily observe reductions in feeder load soon after the feeders' voltages have been reduced, the project could not consistently observe such a reduction from the data that the city had submitted. In fact, an *increase* in load was calculated by the project for the periods that the voltage had been reduced. Furthermore, the increase was found in both feeder-level and premises data. Researchers hope to revisit this analysis and learn why the analysis results were contradictory.

About 100 voltage-responsive water heaters were installed at premises on four of the city's feeders. These four feeders were among the nine city feeders that were affected by the aforementioned 4.5% voltage reductions. These water heaters recognized the voltage reduction as their signal to fully curtail the water heater load without requiring the complexity of wired or wireless communications to the devices. The project found the voltage-responsive water heaters to have reliably curtailed about 170 W each, on average, during the voltage-reduction events. City staff was concerned that the water heaters' owners might be inconvenienced if the water heaters were curtailed for multiple hours. Had these voltage-responsive water heaters not been collocated on the feeders where the city practiced dynamic voltage reduction, the city says it probably would have conducted more and longer voltage-reduction events.

The city tested convention CVR on four of its distribution feeders. For almost two years, city staff toggled the system to reduce the feeders' voltages by about 1.5% every other week. The project calculated that the power had been reduced about 26 kW, on average, during the times that voltage was reduced. This is about 0.8% of the typical load on these feeders. The city had anticipated a more beneficial impact from its CVR, and researchers hope to revisit this analysis and its methods in the future to see if those impacts were understated.

Among the lessons that it learned during the PNWSGD, Milton-Freewater, a small municipality, said that it had badly underestimated the staff time it would take to participate in the PNWSGD. They underestimated the time it would take to implement the project and to complete necessary accounting and reporting. The city has no information technology department and must rely on consultants to help with its computer and computer security issues. The city says it has a much clearer understanding of cyber security now than it did prior to the project.

While the city continues to have strong relationships with its vendors who helped it during the PNWSGD, some of the vendors' claims were found to have been optimistic. Milton-Freewater is still working toward a more automated system that will help it shave its monthly peak demand. Its present system lacks functionality, and it required a difficult integration between the city's SCADA and meter data management systems. The DRUs cannot yet be addressed and controlled differently according to the classes of devices that they control (e.g., water heaters vs. air conditioners). And the city received some calls from its residents because of confusing indicator lights on its vendors' devices.

All four asset systems that were installed by the city during the PNWSGD remain installed and useful.