# 8.0 Benton PUD Site Tests

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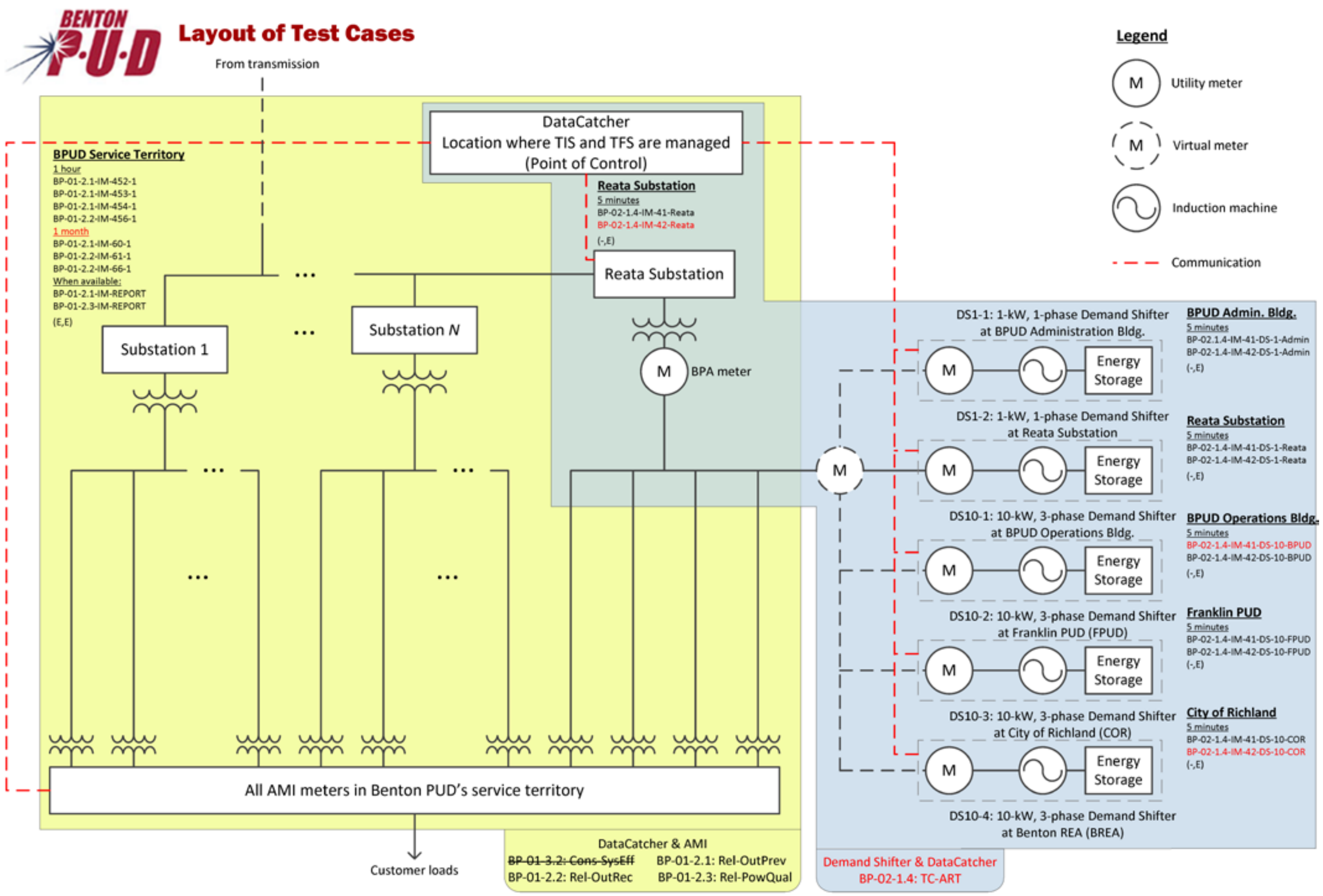
Benton PUD is a public utility district (PUD) that serves almost 50 thousand customers. It serves 939 square miles, including Kennewick, Washington, and has summer and winter peak loads of about 400 MW (Benton PUD 2014). Benton PUD had already installed smart meters at most of its customer locations by the beginning of the Pacific Northwest Smart Grid Demonstration (PNWSGD) project and completed the installations by 2012. The utility was eager to demonstrate the capabilities and benefits of the approximately 48,000 advanced customer meters.

The utility initially defined two demonstration components within the project:

- DataCatcher™ and advanced metering infrastructure (AMI) advance meter capabilities. These track data collected in Benton PUD's "5-bit" program, where the 5 bits represent five power-quality alerts that are communicated back to the utility. The alerts include low voltage, high voltage, hot socket, and outage, (and could include tamper). Information from the installed meters might reduce response time by the PUD to outages.
- Demand Shifter™ and DataCatcher energy storage. Two 1 kW and three 10 kW battery energy storage units were installed by the PUD and by its neighboring utilities. These units were to be responsive to the project's transactive control system.

These two asset systems are shown overlaid on the Benton PUD distribution circuits in Figure 8.1. The investigation of the alerts that are made available from advanced metering (DataCatcher and AMI) covers the entire Benton PUD service territory. The investigation of the energy storage response to transactive control was to be evaluated in reference to a transactive feedback signal representing the load served from the utility's Reata substation.

The layout diagram references several of the shorthand names applied to data series (or "data streams") that were to be collected from the utility by the project. The U.S. DOE sponsor of the PNWSGD had requested that the project measure impact metrics ("IM"), which list was the basis of the shorthand naming practices that were employed by the project. A compressed list of the Benton PUD data is shown in Table 8.1. The table includes the negotiated data intervals at which the data series were collected and a description of each data series. Within the data stream names, asterisks ("*") represent wildcards, where additional text or numbers were appended to specify multiple instantiations of the data series.




| | AMI 5 Bits | | | | |
|---|---|---|---|---|---|
| Test Case | Low Voltage | High Voltage | Hot Socket | Outage | ~~Tamper~~ |
| ~~BP-01-3.2~~ | | | | | X |
| BP-01-2.1 | X | X | X | | |
| BP-01-2.2 | | | | X | |
| BP-01-2.3 | X | X | | | |

**Figure 8.1**. Benton PUD Layout Diagram

**Table 8.1**. Names Used for the Data Series that were Submitted to the PNWSGD Project by Benton PUD. Some of these names are referenced in the Benton PUD layout diagram.

| Data Stream | Data Interval | Description |
|---|---|---|
| BP-02-1.4-IM-41-Reata | 5 min. | Real Power at Reata substation |
| BP-02-1.4-IM-41-DS-1-* | 5 min. | Real Power at a 1 kW Demand Shifter |
| BP-02-1.4-IM-41-DS-10-* | 5 min. | Real Power at a 10 kW Demand Shifter |
| BP-02-1.4-IM-42-Reata | 5 min. | Reactive Power at the Reata Substation |
| BP-02-1.4-IM-42-DS-10-* | 5 min. | Reactive Power at a 10 kW Demand Shifter |
| BP-01-2.1-IM-60-1 | 1 year | SAIFI |
| BP-01-2.2-IM-61-1 | 1 year | SAIDI |
| BP-01-2.2-IM-66-1 | 1 year | CAIDI |
| BP-01-2.1-IM-452-1 | 1 hour | Number of abnormal meter temperature occurrences |
| BP-01-2.1-IM-453-1 | 1 hour | Number of abnormally low meter voltage occurrences |
| BP-01-2.1-IM-454-1 | 1 hour | Number of abnormally high meter voltage occurrences |
| BP-01-2.2-IM-456-1 | 1 hour | Number of outage report occurrences |

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

## 8.1 DataCatcher and AMI

Benton PUD contracted Resource Associates International, Inc., (RAI) to install its DataCatcher software product integrated with the utility's system of advanced premises meters. This software acquires meter event data from Benton PUD's existing set of Sensus Flexnet™ two-way wireless AMI meters (Sensus 2015). This asset system focused on five indicators that are available from the existing AMI customer meters, which Benton PUD refers to collectively as its "5-bit system:"

- abnormal-temperature alarm (hot socket)
- outage alarm (loss of voltage)
- high-voltage alarm
- low-voltage alarm
- tamper alarm.

Benton PUD intended to use these indicators toward reaching three closely related reliability objectives:

- Use reports of high temperature and low or high voltage from AMI meters to anticipate and prevent customer outages.
- Use the AMI outage indicator to more rapidly detect and restore customer outages.
- Use reports of low and high voltages to correct voltages and reduce cases where customers are supplied their electricity outside accepted voltage ranges.

The tamper alarm is useful to Benton PUD, but it was not employed for the objectives to be tested.

Table 8.2 estimates the annualized costs of the system and its components. The costs of the system's components were to be shared equally between the utility's two asset systems. The systems' component costs were for software system integration and for the DataCatcher software product from RAI. The total annualized cost of the system was estimated to be $30.6 thousand per year.

**Table 8.2**. Estimated Annualized Costs of the DataCatcher System

| | Component Allocation (%) | Annualized Component Cost ($K) | Allocated Annual Component Cost ($K) |
|---|---|---|---|
| Software System Integration | 50 | 38.2 | 19.1 |
| DataCatcher | 50 | 23.0 | 11.5 |
| **Total Annualized Asset Cost** | | | **$30.6K** |

### 8.1.1 Analysis of Reliability Indices for This Asset System

This asset system was applied to the entire distribution utility circuit. Only indices aggregated for whole years and for the entire distribution system were available, and these values are summarized in Table 8.3.

**Table 8.3**. Yearly Reliability Indices over a Five-Year Period

| | 2010 | 2011 | 2012 | 2013 | 2014[(a)] |
|---|---|---|---|---|---|
| SAIFI (outages per customer per year) | 0.35 | 0.33 | 0.60 | 0.36 | 0.26 |
| SAIDI (outage minutes per customer per year) | 40.4 | 42.3 | 74.9 | 53.4 | 28.7 |
| CAIDI (minutes per outage) | 116.1 | 126.5 | 124.6 | 147.5 | 108.9 |

(a) All months of calendar year 2014 are included in the calculated indices even though the project's formal data collection period ended September 1, 2014.

While 2014 yielded the best system reliability numbers in recent years, the project cannot conclude from this limited data that system reliability has improved with the new information that is available from advanced metering and the coordination of this information with other utility systems. If improvements in system reliability had been evident, they might have been attributable to improvement in standard utility operations and practices.

The following charts summarize the counts of the alerts that were made available from the utility's metering upon the meter detecting high temperature, low voltage, high voltage, or an outage. Benton PUD worked with the project to assemble numbers of each type of alert per hour. The project stored these data in its database as counts per interval, which means that 5-minute data intervals within an hour are each allocated one-twelfth of the count. While this seems awkward at first, it facilities combination of time series that have different base-interval durations, and it allows summing of counts over increasingly long data intervals.

The project's ability to analyze the five years of data (2010–2014) and draw conclusions is limited due to configuration changes that occurred during the project. From 2010 to 2012, the AMI system configuration was consistent, but in 2013 the AMI communications network was reconfigured to utilize a priority channel for all AMI meter alerts, significantly increasing the count of meter alerts by improving the reliable transmission of the messages. Prior to this change, events were likely occurring; however the alert messages were not being reliably delivered. In addition, the configuration changes in 2013 resulted in the DataCatcher collecting duplicate messages for high- and low-voltage alerts for several months before the issue was recognized and corrected. For these reasons, the data from 2013 is invalid for analysis and trending of voltage alerts.

### 8.1.2 Abnormal-Temperature Alerts Reported by Advanced Meters

Figure 8.2 shows the count of abnormal-temperature alerts collected by Benton PUD from all its meters each project month. These alerts were infrequent. No alerts were received during many of the months. The most alerts, 23, occurred during July 2014, which had several weeks of extreme heat that contributed to counts higher than normal. The utility says these were false alerts caused by the ambient conditions rather than by electrical issues.

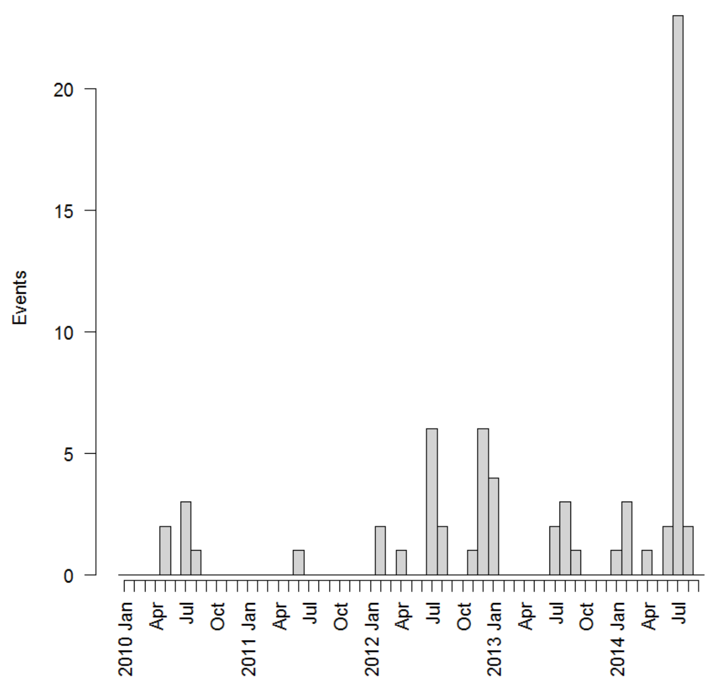
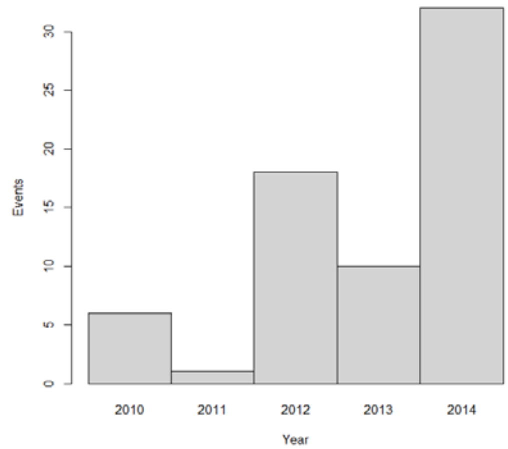


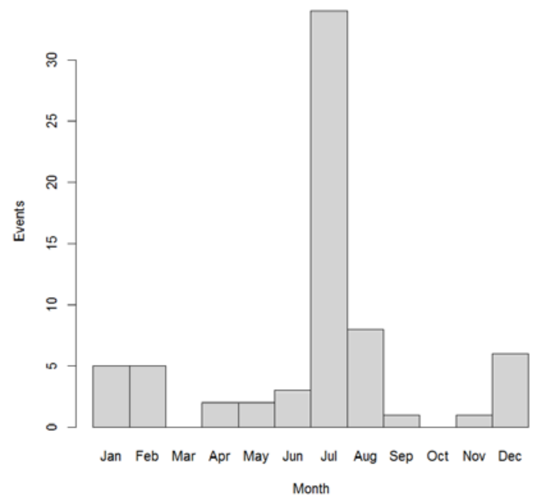

**Figure 8.2**. Counts of Meters Reporting Abnormal Temperature each Month

Next, analysts looked at the distributions of these alerts across several additional dimensions to see whether interesting trends might be observed. Figure 8.3 presents the same alerts in Figure 8.2, but they are here grouped according to the year, month, day of week, or local hour in which they occurred. Most of the counts had been shown in Figure 8.2 to have occurred during July 2014. That month of 2014 also caused July to be the calendar month on which most alarms were received, as shown in Figure 8.3b.

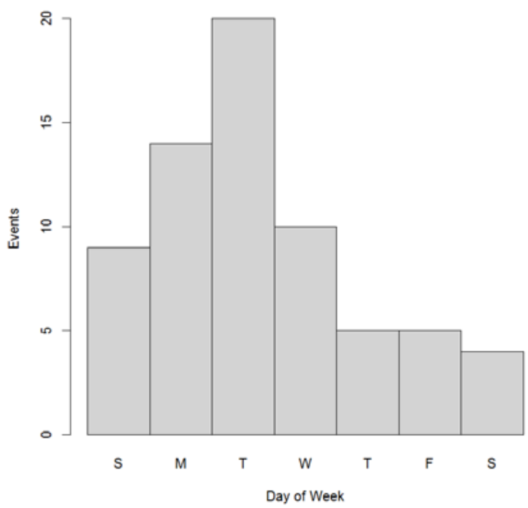
Surprisingly, more events happen in the first half of the work week than in the latter half, as shown in Figure 8.3c. The project has no strong hypothesis why this was the case. Tuesday was the day of week on which most abnormal-temperature alerts occurred. Based on Figure 8.3d, the alerts are more likely to occur in late afternoon. The value 0 on the horizontal axis represents the hour beginning at midnight local Pacific Time. Fourteen events were tabulated during each of the consecutive hours 16:00 and 17:00, local Pacific Time.



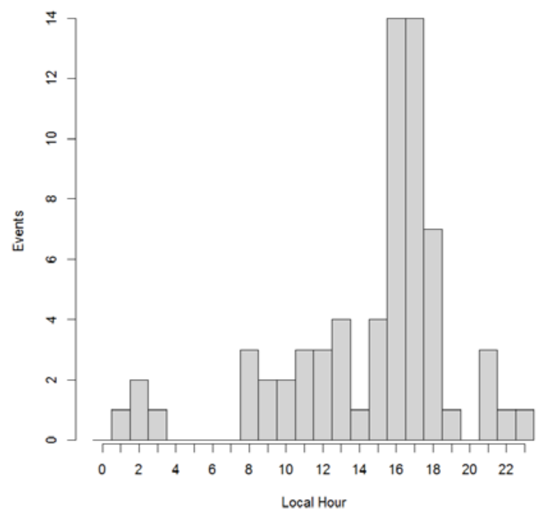

(a) By Year[1]




(b) By Month




(c) By Day of Week




(d)

By Local Hour

**Figure 8.3**. Distributions of Abnormal-Temperature Events by (a) Calendar Year, (b) Calendar Month, (c) Day of Week, and (d) Local Hour

[1] Data for year 2014 includes January–August 2014, inclusive.

### 8.1.3 Low-Voltage Alerts Reported by Advanced Meters

The project next looked at the low-voltage alert. This alert should be generated by any meter that encounters a voltage lower than the accepted supply range. These alerts were summed each project month in Figure 8.4. These alerts are apparently common. The vertical axis was changed to report thousands of occurrences, in this case. The top of this bar was cropped in the figure so that variations for the other months might be better seen.

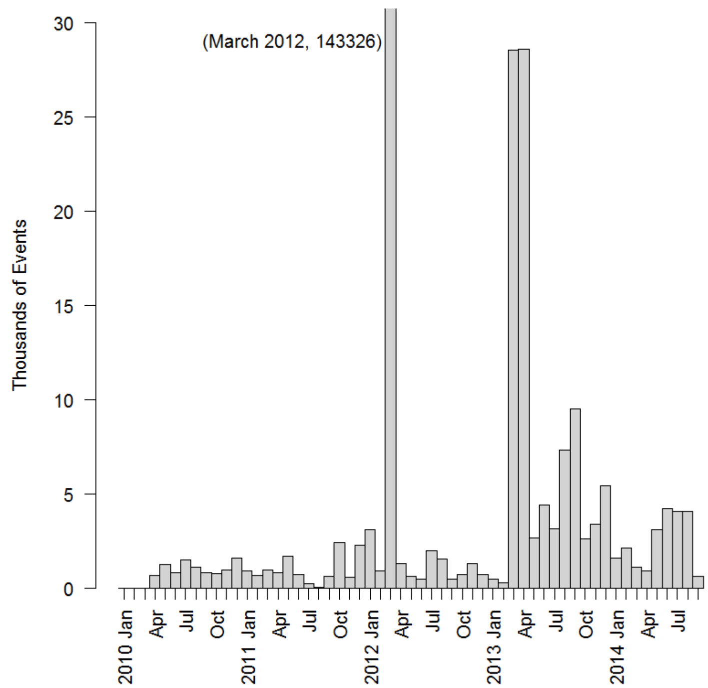
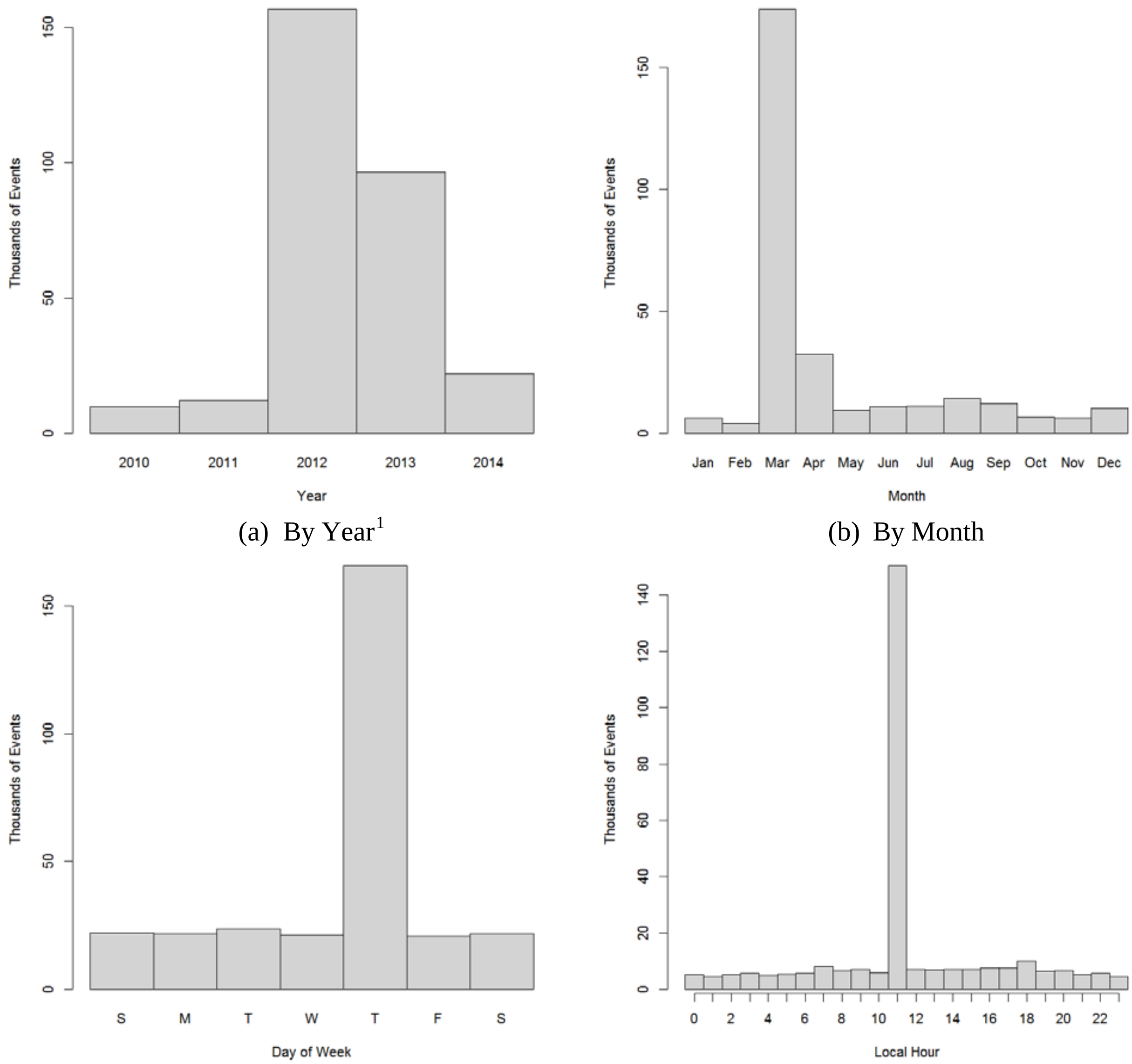



**Figure 8.4**. Counts of Meters Reporting Abnormally Low Voltage Each Month. The top of this figure has been cropped due to the outlier month March 2012, when 143,326 abnormal low-voltage occurrences were reported.

As reported in the introduction to this section, the low-voltage counts for 2013 are not valid for analysis due to an issue with duplicate alert messages being received during a portion of the year. The 2014 counts are valid, but they are expected to be higher than the counts for 2010 to 2012.

The very large number of alerts from March 2012 was also found to greatly influence the four distributions in Figure 8.5. The year 2012 and the month of March exhibited the greatest numbers of these occurrences. Upon further investigation, a single event on March 15, 2012, was found to have occurred during hour 11:00, and that day was a Thursday. These are precisely the hour and day of week when, overall, the most of these low-voltage alerts were found to have occurred. It was discovered that these alerts were all generated by a group of nine meters that were erroneously repeating their alarm messages and flooding the system with invalid alerts.




(a) By Year[1]

(b) By Month

(c) By Day of Week

(d) By Local Hour

**Figure 8.5**. Distribution of Low-Voltage Events by (a) Calendar Year, (b) Calendar Month, (c) Day of Week, and (d) Local Hour

[1] [1] Data for year 2014 includes January–August 2014, inclusive.

### 8.1.1 High-Voltage Alerts Reported by Advanced Meters

Figure 8.6 shows the counts of high-voltage alerts received from advanced metering each project month from 2010 through the end of August 2014 when the project's formal data collection period ended. As reported in the introduction to this section, the high voltage counts for 2013 are not valid for analysis due to an issue with duplicate alert messages being received during a portion of the year. The 2014 counts are valid, but they are expected to be higher than the 2010 to 2012 counts.

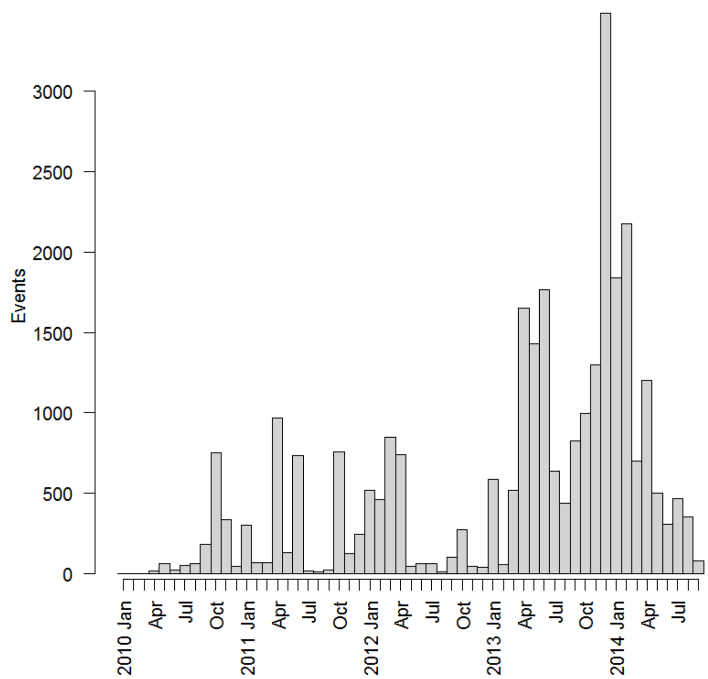
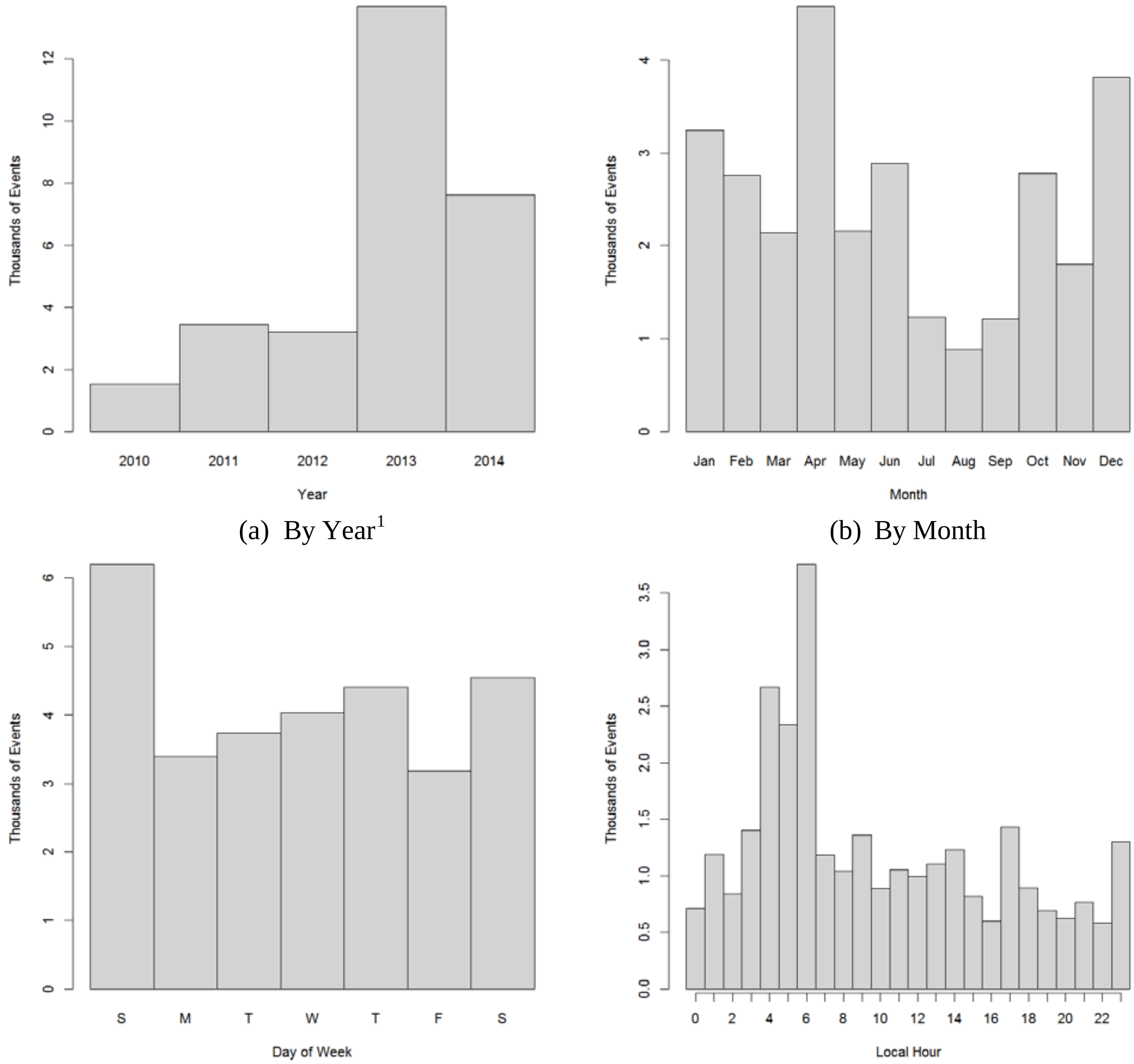



**Figure 8.6**. Counts of Meters Reporting Abnormally High Voltage Each Month

Figure 8.7 shows distributions of these same high-voltage alerts by the calendar year, calendar month, day of week, and local hour, Pacific Time. According to panel (a), the high-voltage alerts peaked in 2013. Based on panel (b), high-voltage alerts are at their minimum during summer months. This might indicate a relationship between these occurrences and the utility's yearly voltage management practices. High-voltage alerts are most prevalent on Sundays according to Figure 8.7c, but the occurrences are otherwise evenly distributed among the days of the week. Figure 8.7d suggests that high-voltage events occur most often from 04:00–06:00 in the morning, perhaps related to management of voltage in preparation for peak load hours.




(a) By Year[1] (b) By Month

(c) By Day of Week (d) By Local Hour

**Figure 8.7**. Distribution of High-Voltage Events by (a) Calendar Year, (b) Calendar Month, (c) Day of Week, and (d) Local Hour

### 8.1.1 Outage Alerts Reported by Advanced Meters

Figure 8.8 shows the counts of outages that are reported by advanced premises meters each month from 2010 through August 2014.

[1] The year 2014 included data from January through August 2014.

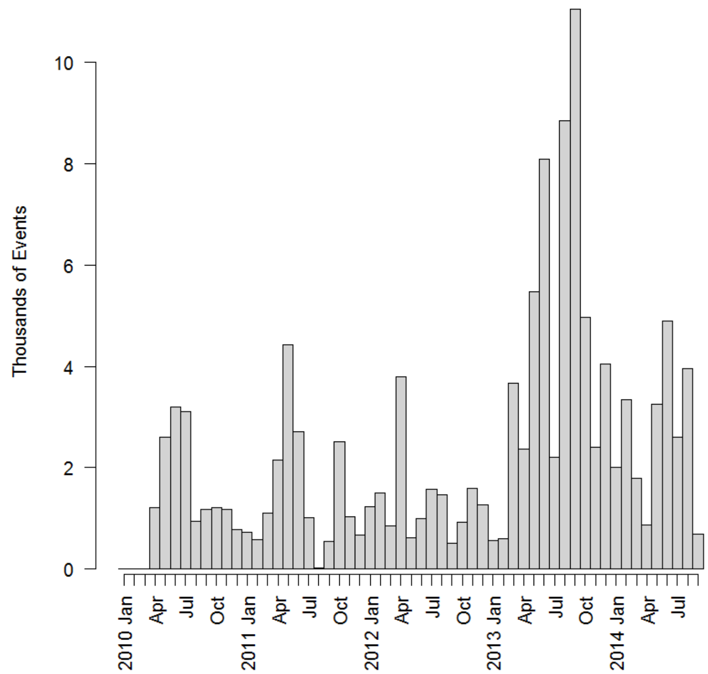



**Figure 8.8**. Counts of Meters Reporting Power Outages each Month

As reported in the introduction to this section, the counts for 2013 and 2014 are greater than those for the previous years (2010–2012), as expected, due to the configuration changes. An unexpected result of reviewing the data is a realization that the magnitudes of the counts are far greater than expected and are not valid. It appears that the test case's data stream delivered more alerts to Battelle than expected. For example, Benton PUD's own DataCatcher database analysis indicates that the most alarms occurred in 2013, which is in agreement with the project's data analysis; however, Benton PUD's total outage alert count for 2013 is only 13,759, while the project's count for the same year is more than 50,000.

One possible explanation for the project receiving too many outage alerts is that the data stream was not properly configured to filter out duplicate messages. It is common during an AMI meter outage event for the meter to send up to five or six "last gasp" outage alerts to increase the probability that at least one message will be reliably transmitted back to the head-end system. The AMI communications network uses four base station transceivers located on nearby mountain tops that listen for these "last gasp" outage alerts. To further ensure reliable transmission of messages to the head-end system, the outage alerts may also be repeated from multiple base stations back to the head-end system. The DataCatcher integration to the AMI head-end system was designed with logic to filter out the repeat outage alerts and to only store a single outage event. It is possible that this filtering logic was not being applied within the coding that generated the outage alert data stream being sent to Battelle.

Although the AMI meters and the communications system are designed to repeat the outage alerts to improve the reliability of successfully transmitting the message back to the head-end database, the system is still not expected to always receive outage alerts from 100% of the affected meters. For an outage involving only a few meters, it would not be uncommon to receive 100%, but as the meter count increases the percentage decreases. For example, in a typical outage involving several hundred customers, it may drop to around 80%, and for a few thousand customers it may drop to around 50%. The DataCatcher's outage alert data, when properly filtered for repeat alarms, provides an approximation of the number of customers who experienced outages over a given time period, but the total count will always be lower than the number of customers who actually experienced an outage.

It is expected that outage alert counts should correlate with SAIFI if the alerts are being received with relatively high reliability and if they are being properly filtered to exclude duplicates. Prior to 2013, the outage alerts were not being reliably transmitted and there were repeat alarms. Therefore, correlation with SAIFI is not valid before 2013. Data for 2013 and 2014 should better correlate with SAIFI because the configuration improvements should result in a higher percentage of outage alerts being received. However, the data still contains duplicate alerts and cannot be compared to the previous years (2010–2012) because of the configuration change.

The distributions of these outage alerts according to the calendar year, calendar month, day of week, and local Pacific Time hour on which the alerts occurred are shown in Figure 8.9. Based on Figure 8.9b, the occurrences of outage alerts roughly correspond to outdoor temperature. The greatest numbers of outages were reported in June, and the fewest in January. Outage alerts were fairly evenly distributed across all days of the week, according to panel (c). Perhaps there is a tendency for outages to have occurred midweek, since the days with the greatest number of alerts were Tuesdays, Wednesdays, and Thursdays. Because of the unknown distribution of duplicate alerts, it is difficult to draw any firm conclusions.

According to Figure 8.9d, most outages are reported by advanced metering during daylight hours.

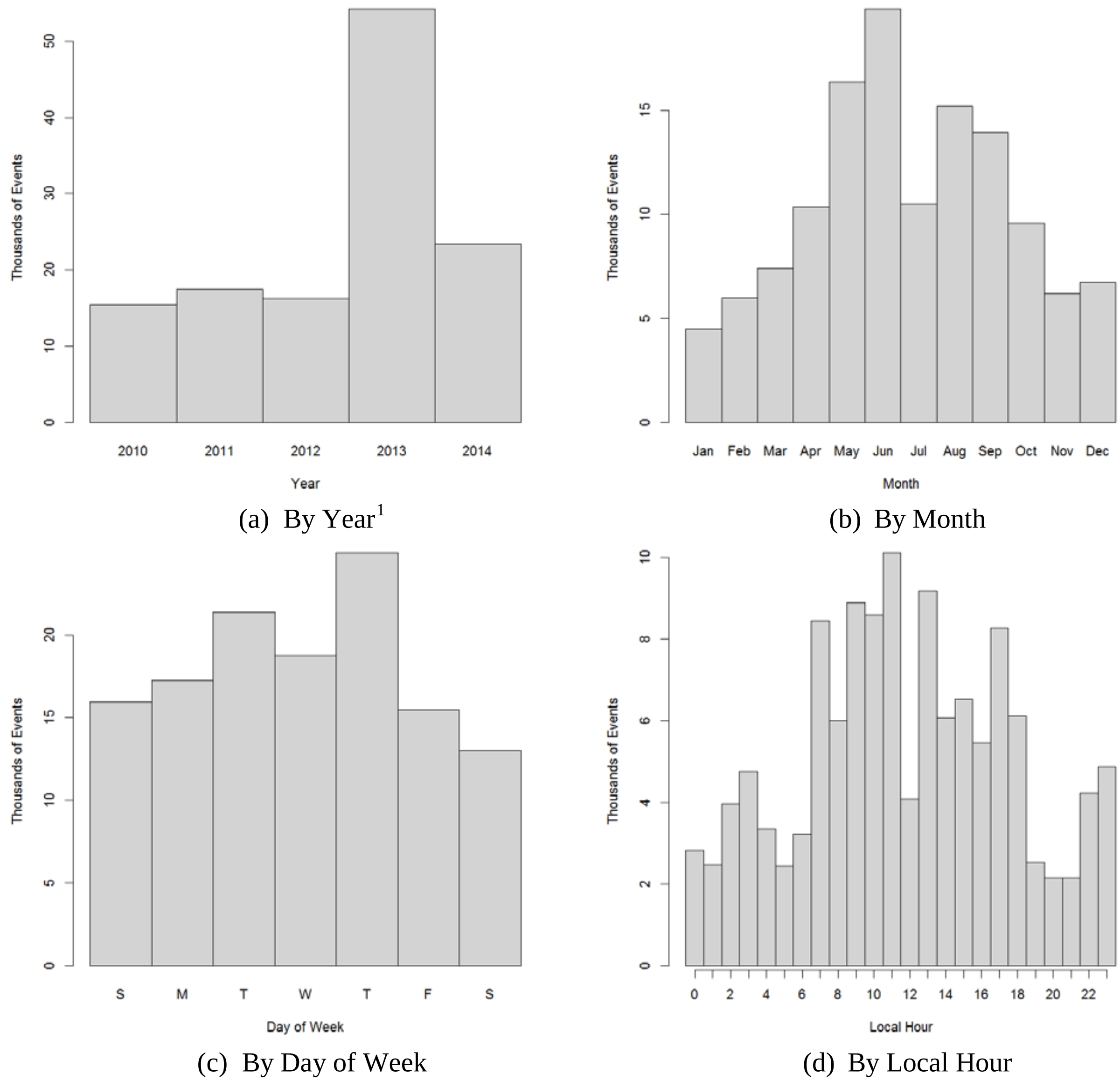



**Figure 8.9**. Distribution of Outage Events by (a) Calendar Year, (b) Calendar Month, (c) Day of Week, and (d) Local Hour

## 8.2 Demand Shifter and DataCatcher

Benton PUD, collaborating with neighboring utilities Franklin PUD and the City of Richland, Washington, installed five battery energy storage units: three had ratings of 10 kW, 40 kWh and two had ratings of 1 kW, 5 kWh. The 10 kW energy storage units were made by Demand Energy Networks (Demand Energy Networks, Inc. 2014) who called the systems Demand Shifters. The 1 kW energy storage units were prototypes developed by RAI, which were integrated with their DataCatcher software

[1] The year 2014 included data from January through August 2014.

application for monitoring and control. RAI and Demand Energy Networks worked together to enable the 10 kW units to also be managed by the DataCatcher. Benton PUD wished to demonstrate that these units could charge when the nearby Nine Canyon Wind farm was producing wind energy, and then discharge this energy during the PUD's peak demand periods. Wind energy would then be better used and the utility's demand curve would also be flatter.

Of these five battery storage systems, the two smaller 1 kW systems were not reliable enough to keep working, and since they were prototypes, they were not worth any continued efforts to keep them running. Data from these two smaller units faltered and stopped during the project's data collection period. The capabilities of these small 1 kW units could not be confirmed by the project.

Benton PUD installed one 10 kW storage module at its headquarters in Kennewick, Washington, and it coordinated with two neighboring utilities to install and monitor two more 10 kW units at these neighbors' sites. The three 10 kW units were installed and unit tested, but they never truly became responsive to the project's transactive control system. First, the site's transactive node never achieved full function, and the energy storage devices never became automatically controlled by the transactive system. Benton PUD opted to code its own implementation for the transactive system, an effort that proved more challenging than had been anticipated by them. While the Benton PUD transactive site eventually achieved the ability to exchange conformant signals with the larger transactive system, its participation faltered in 2013. The site never again communicated with the transactive system. Demand Energy Networks, Inc. stopped supporting these energy storage products around October of 2013. The energy storage products could not be operated without web-based software operated by this vendor.

Table 8.4 estimates the annualized costs of the energy storage system and its components.

**Table 8.4**. Estimated Annualized Costs of Demand Shifter System

| | Component Allocation (%) | Annualized Component Cost ($K) | Allocated Annual Component Cost ($K) |
|---|---|---|---|
| Demand Shifter | 100 | 46.5 | 46.5 |
| Transactive Control | 100 | 26.3 | 26.3 |
| Substation BPA Meter Interface | 50 | 0.4 | 0.2 |
| **Total Annualized Asset Cost** | | | **$84.5K** |

BPA = Bonneville Power Administration

### 8.2.1 Data from the Energy Storage Modules

The project received no useful data concerning status of any of the five battery energy storage modules. Therefore, little can be said about the intentions of the utilities as they operated these devices. No connection was completed between the devices and the project's transactive system. While Benton PUD had once indicated that they would coordinate the charging and discharging of the storage modules with utility-owned wind generation resources, the project believes this connection was not automated or completed.

The project did, however, receive data concerning the power exchanged by the modules. Figure 8.10 shows the power exchanged between the three 10 kW modules and their distribution systems. Positive power represents charging of the modules, and negative power represents their discharge. Data was collected from most of the three modules from late March 2012 into October 2013. Even though the modules were rated for 10 kW, they typically operated at only about 1 kW or less, per the data received. This discrepancy is likely related to a problem with the data's' units not having been reported correctly. The charging rate appears to have been controlled, creating a continuum of power charging rates. Discharge power was more constant at a few discrete discharge power magnitudes.

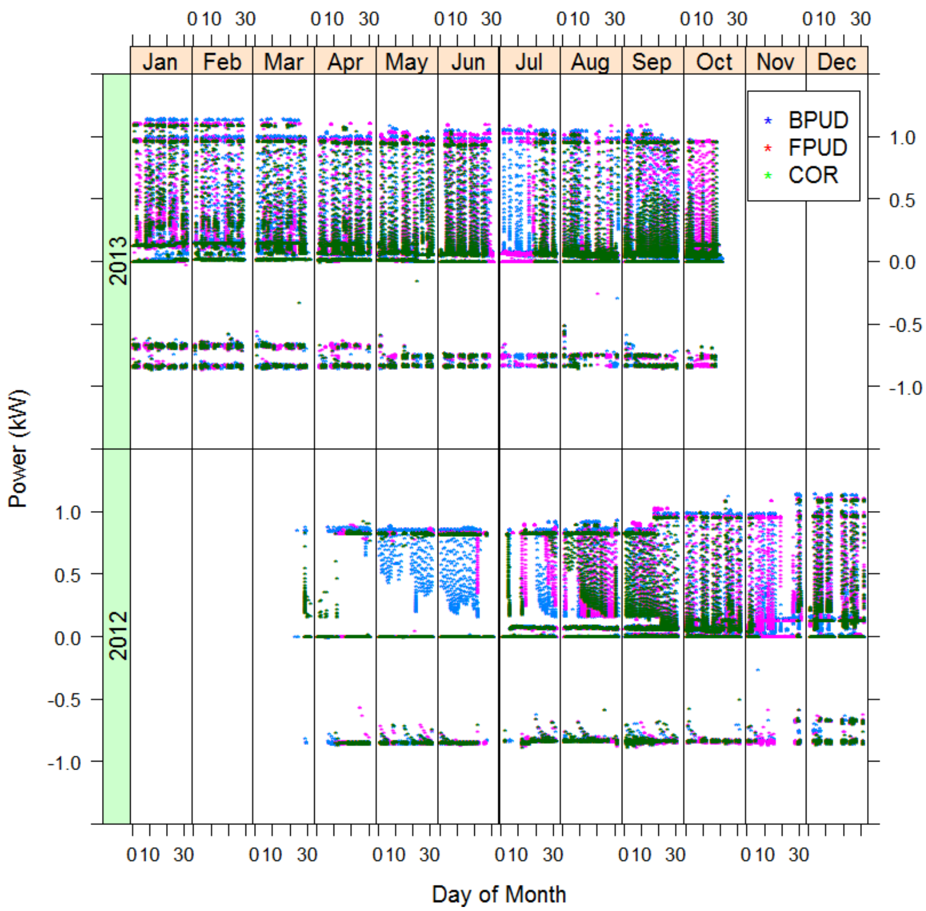



**Figure 8.10**. Power Data Received from Benton PUD Concerning the Performance of Three 10 kW Energy Storage Modules

Power data was also available from the two 1 kW modules, and is shown in Figure 8.11. This data is believed to be the sum power exchange from the two 1 kW modules. The data period was from late March 2012 to early November 2013. There were month-long periods within this range for which data was not available. Data was delivered sporadically until the end of August 2014 when the project's formal data collection period ended, but most of this data was either zero or entirely missing.

Although these two units were rated at 1 kW, they never charged or discharged at more than one tenth of that rating (~100 W), per the data received. This discrepancy it likely related to a problem with the data's units not having been reported correctly. The utility had stated that positive power values represent charging of the batteries, but that will be called into question in the next section.

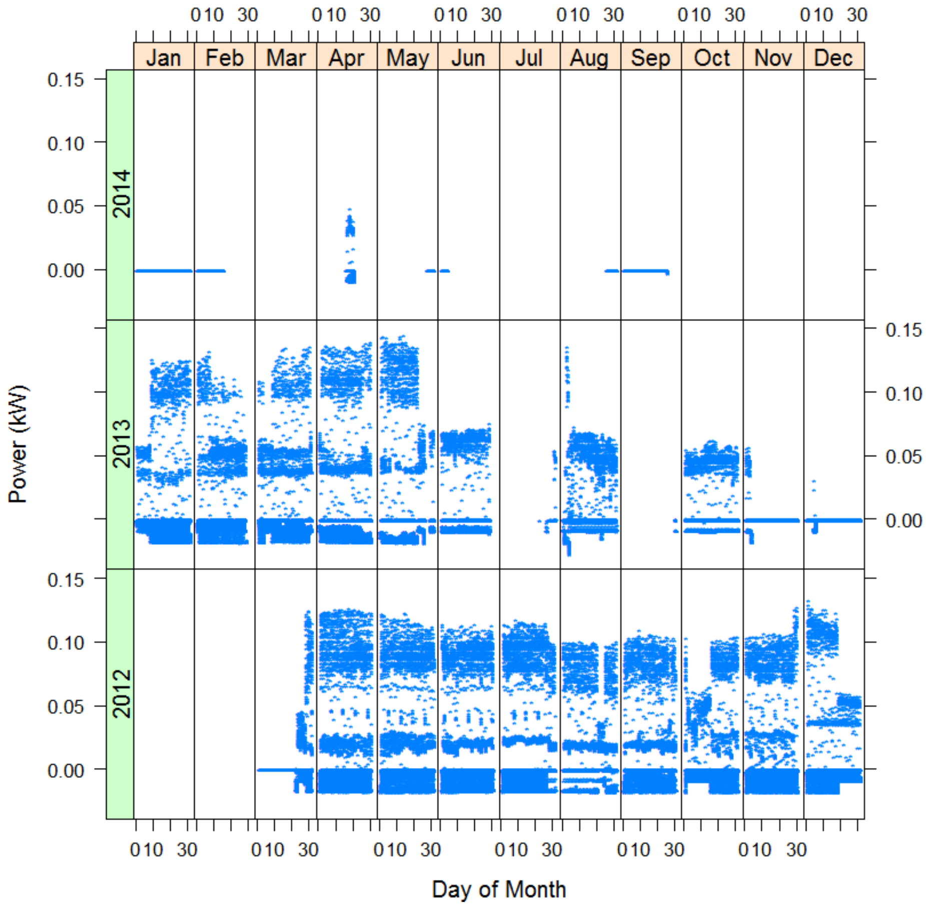



**Figure 8.11**. Power Data Received from Benton PUD Concerning the Sum Power Conversion at Two 1 kW Energy Storage Modules

### 8.2.2 Performance of the Energy Storage Modules

The project analyzed patterns in the operation of the battery storage modules. Figure 8.12 shows the power of the 10 kW modules as a function of time of day. The value 0.0 on the horizontal axis represents midnight local Pacific Time. While there is some variability in the results, the modules' recharging typically began abruptly late in the evening and continued into the morning. The charging rate declined as the batteries were recharged overnight. The batteries were typically discharged around hours 06:00 and 07:00 local Pacific Time.

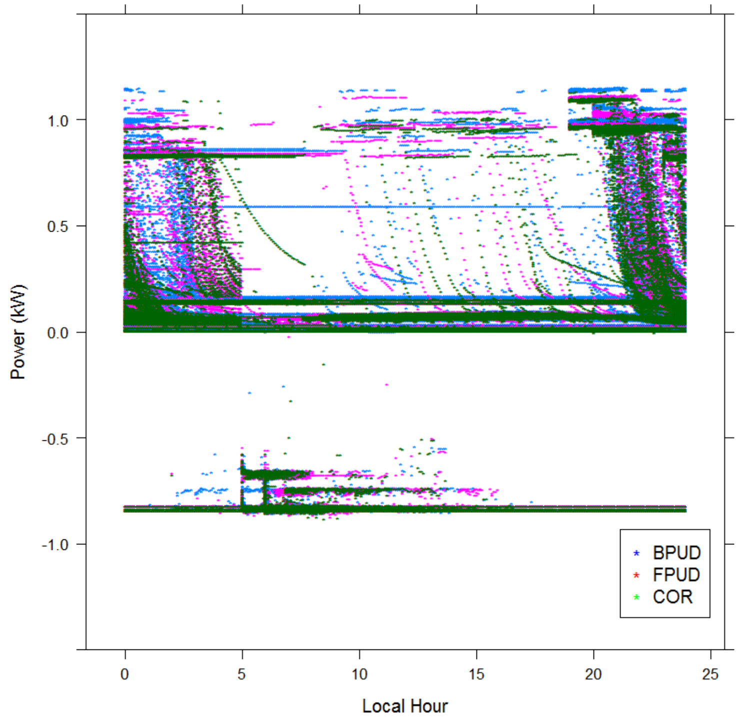



**Figure 8.12**. Power Generation of the Three 10 kW Energy Storage Modules versus Local Pacific Time. Positive power indicates charging of the batteries.

The hourly charge and discharge patterns are perhaps more easily seen in Figure 8.13, which shows the median power and quartiles of operation of the Benton PUD 10 kW battery energy storage module during the project versus the local Pacific Time hour. In these quartile plots, the two boxes above and below the median and the extended bars above and below those boxes represent approximately one fourth of the data points. Some outliers are shown, as well above and below the extended bars. The systems were often discharged during the hours starting 06:00 and 07:00. The plots for the remaining two 10 kW units were similar but are not shown.

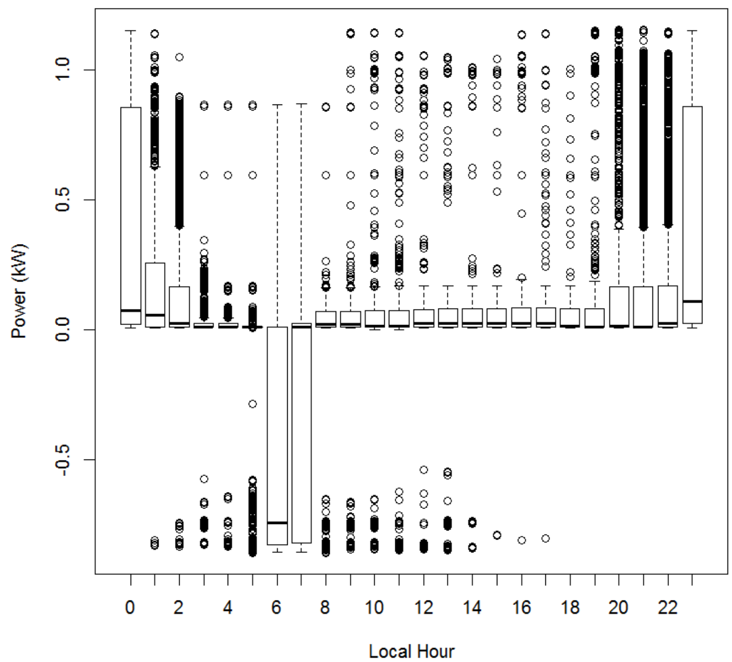



**Figure 8.13**. Quartile Plot of the Charging (Positive) and Discharging (Negative) of the Benton PUD 10 kW Battery Energy Storage Module throughout the Project

The power of the smaller, 1 kW battery energy storage modules is plotted against time of day in Figure 8.14. According to this data, the modules sometimes charged during blocks of time in midmorning or late afternoon. The modules discharge in the late evenings and into the mornings. This pattern of usage does not seem sensible. The project must hypothesize that either the interpretation of the signs of the power has been misstated, or there exists a time shift in the data that was submitted to the project concerning the power of these 1 kW units.

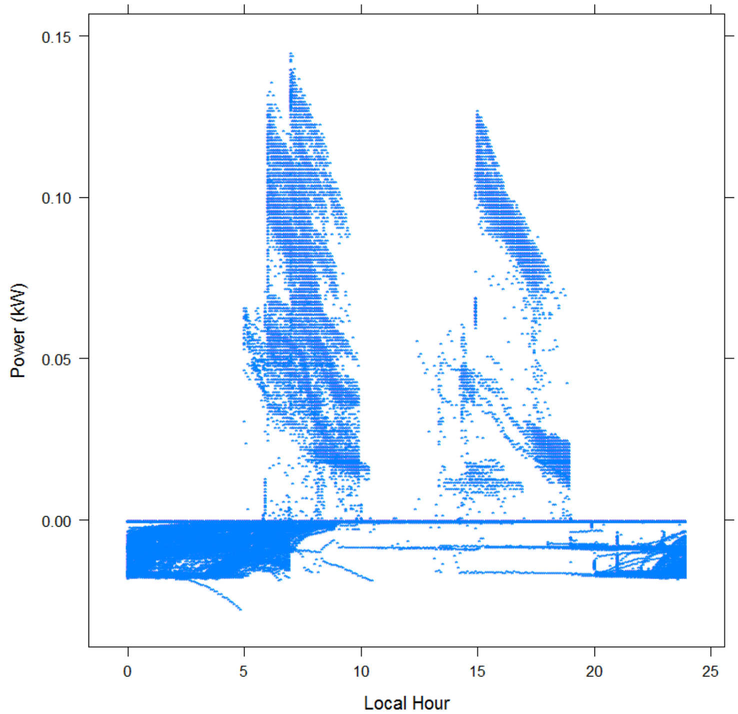



**Figure 8.14**. Sum Power Generation of Two 1 kW Energy Storage Modules versus Local Pacific Time. Benton PUD responded that positive power indicated charging the batteries, but that might be incorrect for these 1 kW modules.

Given that the project's understanding of the control of these devices was limited and the devices became obsolete early in the project, the project conducted no further analysis on the performance of these battery energy storage modules.

### 8.2.3 Conclusions and Lessons Learned

Benton PUD worked with the PNWSGD project to demonstrate two smart grid technologies—power-quality alerts that were being generated by a system of advanced premises meters, and small commercial- and residential-scale battery energy storage.

The utility was able to demonstrate the usage of alerts from its advanced premises metering—its 5-bit project—and was able to collect interesting operational data, including counts from four of the five alert types. Over the life of the project and still ongoing today, the DataCatcher has been a valuable tool being utilized by Engineering and Operations for visibility into real-time system operations and after-the-fact analysis. The standard reliability indices appeared to remain similar throughout the project term. The patterns in the meters' alerts were discussed in this chapter, but no significant improvements in these metrics can be attributed to the project at this time.

Benton PUD's efforts to install and demonstrate a reserve of battery energy storage referenced to the load profile from its Reata substation were partially successful. The modules were installed at the Benton PUD's and two neighboring utilities' facilities. The smaller, 1 kW storage devices were never very productive, but some data was received from the larger, 10 kW modules before the modules' vendor experienced financial difficulties and stopped supporting the devices in 2013.

The utility's attempts to create its own software instantiation and site within the project's transactive system were unsuccessful. While the first system conformance tests were eventually passed early in the project, the utility's vendors were not able to pass later, more complex conformance tests as the transactive system matured.

Benton PUD submitted the following "lessons learned" based on their experiences with the PNWSGD project and the implementations of the two asset systems:[1]

- The discipline of configuration control and change management principles must be applied to AMI meters and communications systems prior to trying to evaluate meter alarms.
- Participation in the PNWSGD project improved Benton PUD's awareness within and between its Engineering and Information Technology staff regarding cyber security best practices.
- As the PNWSGD was a demonstration sponsored by the federal government, project reporting and project management requirements required much more work and were more challenging than had been expected.
- Distributed energy storage technologies are not yet mature, and, as Benton PUD experienced, there is an increased risk that its vendors will go out of business during a project.
- Benton PUD's efforts to develop and implement its own transactive control interface became too complex. The setup of transactive systems will have to become less complex if small utilities like Benton PUD are to participate without being fully dependent on consultants and vendors.[2]
- As a project with a significant research and development component, the PNWSGD project initially required flexibility in its scope of work. As the project tasks and expectations became better defined, Benton PUD should have established payment milestones for its contractor. As it was, contractors struggled with the complexity of the project, which depleted project budget and resulted in several deliverables not being completed.
- Technology continued to evolve over the life of the PNWSGD project. Now, vendors offer software modules and interfaces for handling advanced meter alerts that will take the place of Benton PUD's custom solution that it and its vendors developed during the project. The utility developed several of its functional requirements for implementing this new technology during the course of the PNWSGD project.

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[1] The lessons discussed in these paragraphs have been paraphrased from the unpublished presentation "Benton PUD - Lessons Learned Template.docx" that was last modified by Blake Scherer, Benton PUD, for the PNWSGD project on October 13, 2014.

[2] This bullet refers to the fact that Benton PUD did not accept the reference software implementations that had been developed by IBM and offered by the project. Instead, the utility's vendor attempted to develop its own instantiation based solely on the systems' design specifications.