10.0 Flathead Electric Site Tests

Flathead Electric Cooperative, Inc. is the largest electric cooperative in Montana and serves approximately 49,000 members (FEC 2014a). The cooperative worked with the project to define two demonstration sites within its service territory at the communities of Libby and Marion/Kila, Montana. Two sites were used because the cooperative wished to learn about the technologies as they might be applied in both urban (Libby) and rural (Marion/Kila) locations. Refer to Figure 10.1 for the boundaries from which the cooperative solicited participants for these two sites. The two sites became nodes ST07 (Libby) and ST08 (Marion/Kila) of the project's transactive system.

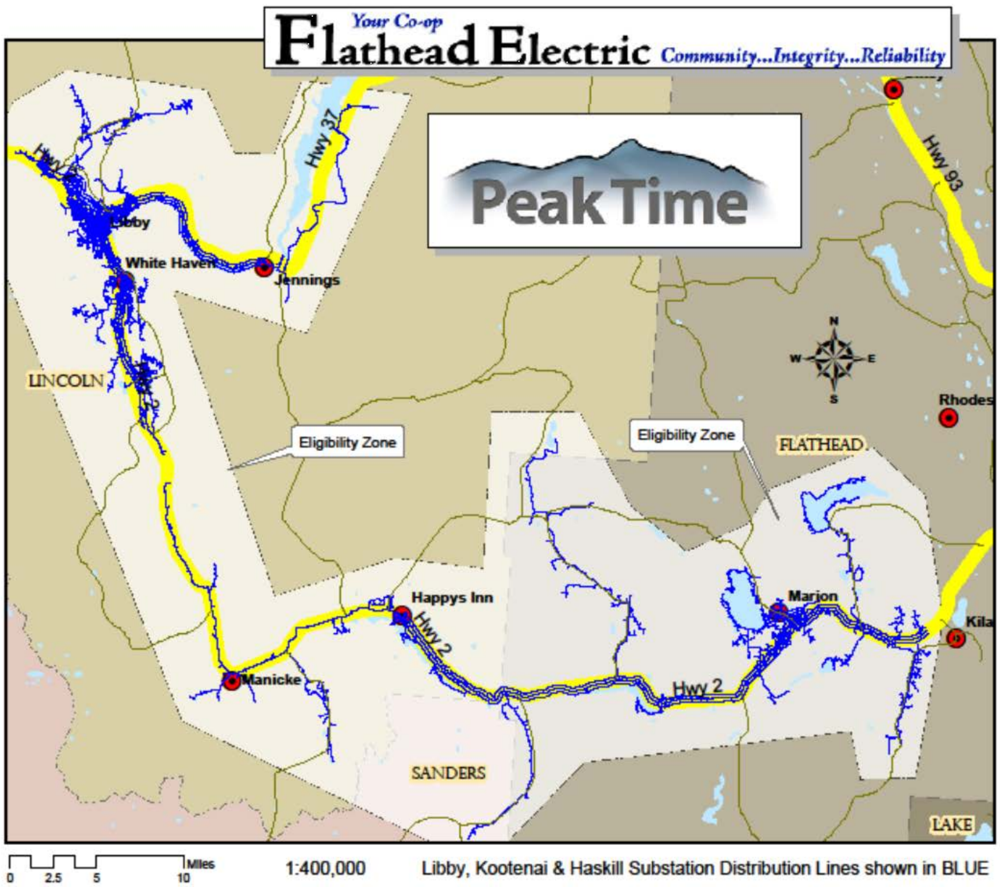

Figure 10.1. The Libby (left top) and Marion/Kila (bottom right) Sites within the Flathead Electric Cooperative Service Region in the Flathead Valley, Montana[1]

[1] In Flathead Electric Cooperative, Inc. (FEC). 2013. Flathead Electric Cooperative Demonstration Project: Peak Time. Unpublished slide presentation file Peak_Presentation_2013.pptx, February 2013, slide 5.

The cooperative is supplied wholesale electric power from the Bonneville Power Administration. An objective of the cooperative's participation in the Pacific Northwest Smart Grid Demonstration was to use the federal investment grant to finish deployment of their automated meter-reading system and develop tools to reduce its members' peak period power costs. This was an opportunity for the cooperative to upgrade substation equipment, install common two-way premises metering throughout the two project sites, improve system reliability, investigate the applicability of various demand-response technologies, prepare for anticipated load growth, and generally modernize their power grid.[1]

Flathead Electric also wished to better inform their members how the members could reduce their future energy costs. Toward this end, they designed and branded the Peak Time™ voluntary demand-response project. The project logo appears above in Figure 10.1. The cooperative hired a demand-response coordinator—a new staff position—to manage the Peak Time program and to recruit, educate, and interact with member participants. Cooperative members could benefit directly from receiving low cost appliances and project devices and corresponding incentive rebates, and they could benefit indirectly from improved service quality, rich energy usage information, shorter outages, and improved billing accuracy. Flathead reached out to its members using newspapers, newsletters, radio, its website, mailings, bill inserts, and community meetings. Ultimately, they were able to attract 290 member participants in Libby (97% of their target) and 49 in Marion/Kila (49% of their target).[2]

The program was anchored by the cooperative's investment in advanced premises metering for every member at the two site communities. Due to similar deployments in other areas of the local distribution system, the cooperative selected the Aclara Two-Way Automatic Communication System (TWACS®) meters (Aclara 2014) and other system components that were needed to gather and send the TWACS power-line-carrier signals. All members were required to accept advanced metering installations and, if they wished to participate in any of the four defined project participation groups, accept additional behind-the-meter technology deployments. Other unique communication protocols besides TWACS were needed in other parts of the system to incorporate General Electric (GE) appliances and to communicate with the project's transactive system. Figure 10.2 summarizes the communication pathways that Flathead Electric Cooperative established to make the component assets communicate and interoperate.

[1] Ibid.
[2] Ibid.

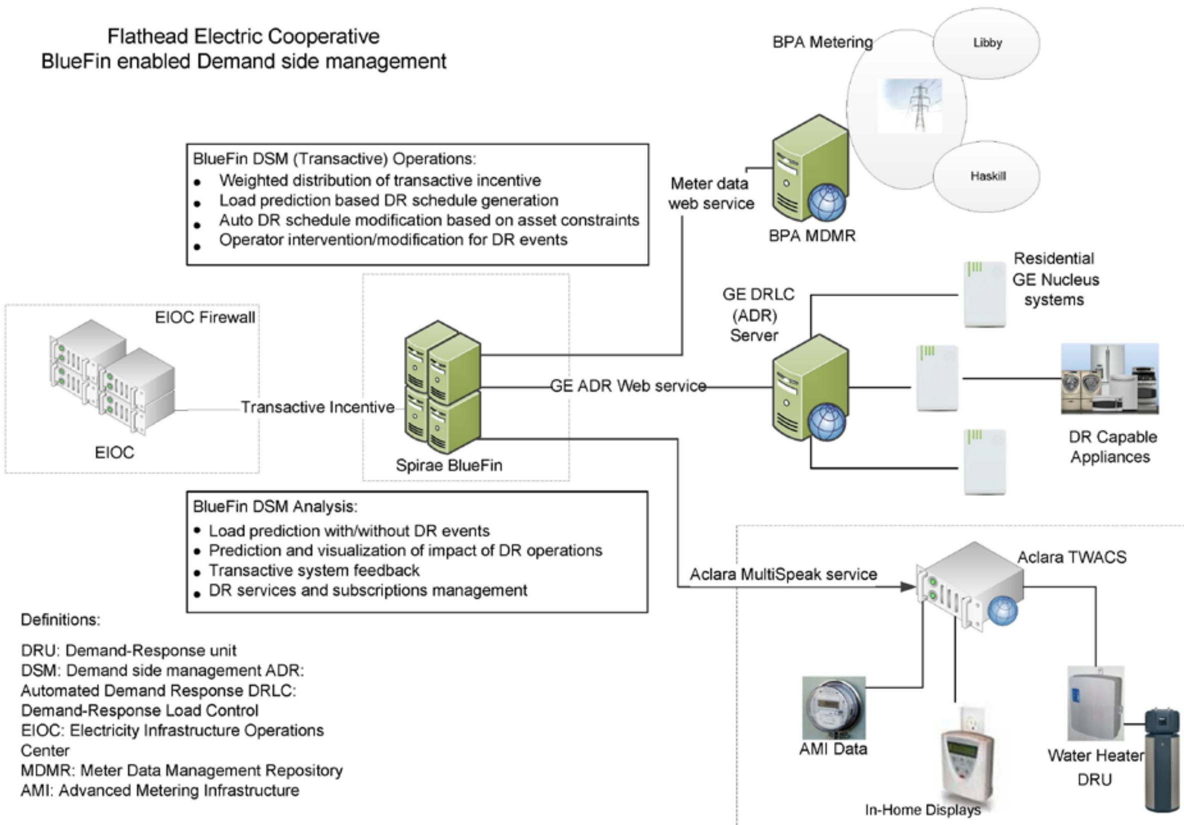

Figure 10.2. Flathead Electric Cooperative's Communication and Interoperability Design for Their Project Assets (Courtesy of Flathead Electric Cooperative)[1]

The following four participation groups were established at the two sites. Each will be discussed in detail in following subsections:

- Group A: These members received advanced premises meters, but they did not receive any of the displays or responsive equipment that those in the other three groups received. The primary purpose of this test group was to confirm that advanced metering can improve the speed with which customers recover after power outages. Aggregated premises metering from this test group provided a comparison baseline for the performance of the other three groups.
- Group B: These members received not only advanced meters, but also in-home displays. Members received signals from the displays and could choose to reduce energy consumption during Peak Time events.

[1] Flathead Electric Cooperative, Inc. (FEC). 2014. Email attachment "FEC design.pdf" from Teri Rayome-Kelly to DJ Hammerstrom Sept. 17, 2014. Unpublished.

- Group C: These members received not only advanced meters, but also demand-response units (DRUs). The DRUs permitted the cooperative to cycle these members' electric water heaters on and off for up to 2 hours during Peak Time events.
- Group D: Members paid $800 and received an advanced meter; energy display; 240 V water heater switch; GE Nucleus™ home energy gateway; and a suite of GE Profile Brillion™ dishwasher, clothes washer, and clothes dryer.

Figure 10.3 shows how these four test populations were laid out similarly at the two Flathead Electric Cooperative sites. The project reviewed reliability indices and outage data concerning the performance of Group A, the baseline group. The cooperative also submitted feeder data for the affected feeders, but premises meter data was the primary source that was used to confirm the performance of Groups B–D.

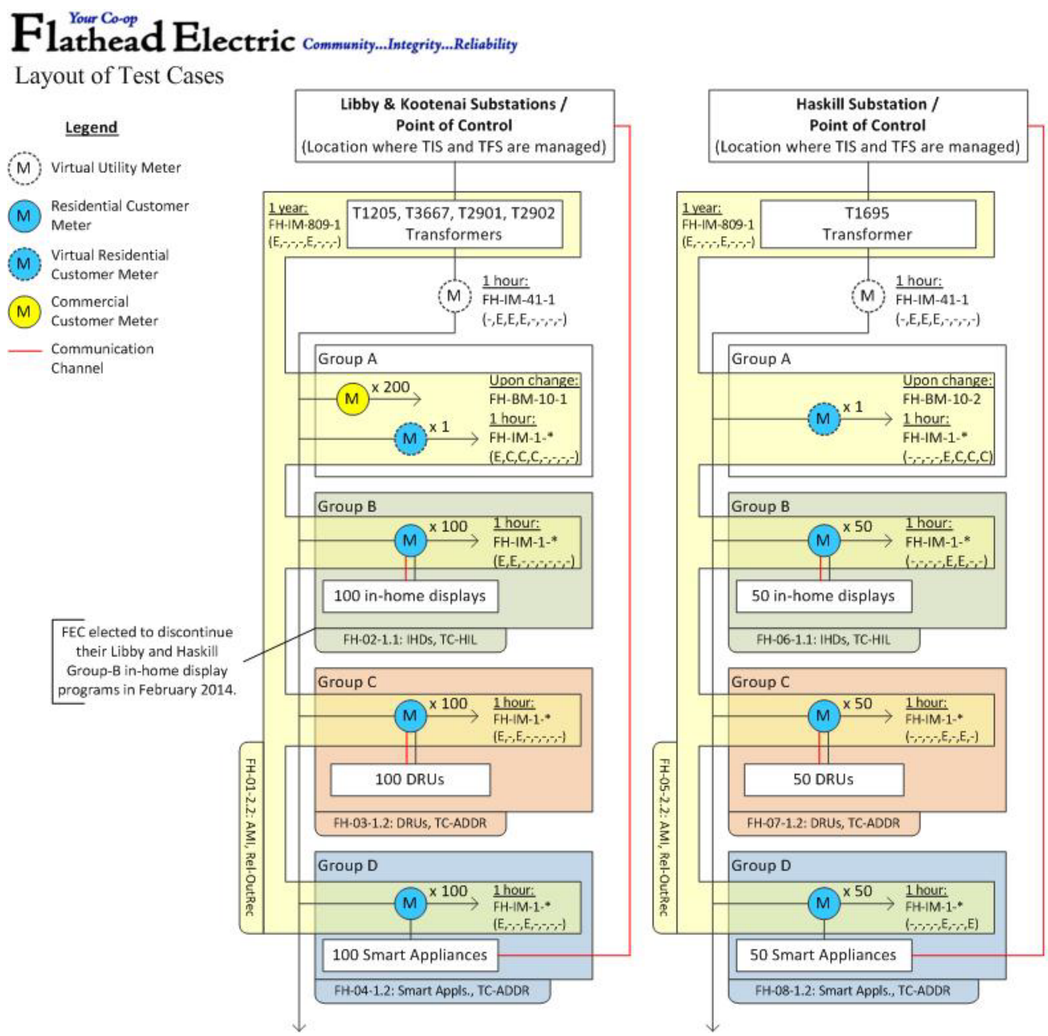

Figure 10.3. Layout of Flathead Electric Cooperative Asset Systems among the Two Sites and by Test Group. Groups A – D in Libby, Montana were served by the Libby and Kootenai Substations, and Groups A-D in Marion/Kila were served by the Haskill substation.

From the start, the cooperative avoided using the terms “smart grid” or “smart meters” with its members, thinking that these terms were perhaps too broad, did not correctly brand the technologies they would be applying, and might not engage their members as they wished. Flathead Electric Cooperative surveyed its members near the conclusion of the project period and compiled the survey results in a 2014 Flathead Electric technical report attributed to Teri Rayome-Kelly[1]. This report has been appended to this chapter (Appendix D). The report summarizes the types of electric loads that members possess and how members typically used these electric loads. Some of the survey questions asked members whether their usage of energy had changed as a result of their project participation. Most telling about the trust that members have for their cooperative is that 97% of respondents said they would participate in a similar program and would recommend participation to other members.

Among the highlights,

- 58% of participants said that electricity is their major source of heating.
- 50% have programmable thermostats.
- 72% said that they changed the way they managed their heating occasionally or more. 36% said they had changed their cooling.
- 58% had elected to conduct efficiency improvements.
- 48% and 52%, respectively, had changed their scheduled usage of their dishwasher and laundry appliances.
- 25% stated they had changed the times that they bathed.

Flathead Electric Cooperative reported that its members’ interest level in the Peak Time project technologies varied greatly. Its members were curious whether these technologies would save energy and benefit the cooperative and its members. The Peak Time branding effort helped them recruit and retain participants, and these participants were perhaps better focused than might have occurred had the technologies been branded instead as “smart.”

A key lesson learned for the cooperative was that the communication technologies were not easily integrated. Because “smart” technologies are advancing so rapidly, industry trends and these products change faster than a utility can react. Product models and features changed between the times the cooperative selected and implemented the technologies. Not all the technologies were as they had been described, and some had not been fully tested to confirm that they would perform in the project’s configurations. Overall, the cooperative’s staff became more involved in and knowledgeable about the installation of the vendors’ products than it had anticipated.

[1] In Teri Rayome-Kelly. 2014. 2014 Peak Time Demonstration Project Member Survey Results. Technical report by Flathead Electric Cooperative, Inc., 121 W 4th St., Libby, MT 59923, September 24, 2014.

10.1 Advanced Metering Infrastructure for Outage Recovery

Flathead Electric Cooperative invested in installation of advanced residential interval power metering at all member premises that are served by its Kootenai and Libby, Montana substations and by the rural Haskill substation west of Kalispell, Montana. It was hoped that these advanced meters would improve the meter-reading frequency and billing accuracy. The meters enabled the cooperative to view complete sets of hourly interval data for each substation, but the cooperative was also interested in the real-time outage information that became available to them as a feature of the new advanced metering infrastructure (AMI). Outage notification continues to be through an automated phone-initiated outage management system, but the TWACS system allows the cooperative to verify outages and narrow exact outage locations for more efficient troubleshooting and restoration. The effectiveness of this improved troubleshooting and restoration was to be measured by changes in reliability indices before and after the asset system had been deployed.

The annualized component costs of the AMI system and its components are summarized in Table 10.1 (Libby, Montana site) and Table 10.2 (Marion/Kila, Montana site). The biggest cost component is the cost of the premises metering system, followed by the cost of utility staff support and the costs of TWACS system components that had to be updated at substations. The Marion/Kila site required new outage management software that was not needed at the Libby site.

Table 10.1. Annualized Costs of Group-A Advanced Metering Infrastructure at the Libby, Montana, Site

	Shared Component Allocation (%)	Annualized Component Cost ($K)	Allocated Annual Component Cost ($K)
Premises Metering			55.2
Group-A Single-Phase Meters	50	72.6	36.3
Polyphase Meters	100	14.7	14.7
Back-End Metering	13	11.7	1.5
Group-B Single-Phase Meters	50	1.5	0.7
Group-C Single-Phase Meters	50	1.5	0.7
Group-D Single-Phase Meters	50	1.5	0.7
Meter Operations and Maintenance	25	2.4	0.6
Staff Support	13	293.1	36.6
Substation TWACS Components			0.9
Modulation Transfer Unit (Model Y87363)	25	1.4	0.3
Inbound Pickup Unit (Model Y83760)	25	0.3	0.1
Outbound Modulation Unit (Model 303)	25	1.3	0.3
Control/Receiving Unit (Model 627)	25	0.9	0.2
Total Annualized Asset Cost			**$92.9K**

Table 10.2. Annualized Costs of Group-A Advanced Metering Infrastructure at the Marion/Kila, Montana Site

	Shared Component Allocation (%)	Annualized Component Cost ($K)	Allocated Annual Component Cost ($K)
Premises Metering			40.5
• Group-A Single-Phase Meters	50	72.6	36.3
• Back-End Metering	13	11.7	1.5
• Group-B Single-Phase Meters	50	1.5	0.7
• Group-C Single-Phase Meters	50	1.5	0.7
• Group-D Single-Phase Meters	50	1.5	0.7
• Meter Operations and Maintenance	25	2.4	0.6
Staff Support	13	293.1	36.6
Outage Management Software	100	17.6	17.6
Substation TWACS Components			0.4
• Modulation Transfer Unit (Model Y87362)	25	0.7	0.1
• Inbound Pickup Unit (Model Y83765)	25	0.2	0.0
• Outbound Modulation Unit (Model 303)	25	0.7	0.2
• Control/Receiving Unit (Model 627)	25	0.4	0.1
Total Annualized Asset Cost			**$95.3K**

10.1.1 Reliability Data

In order to begin understanding whether grid modernization at these two Flathead Electric Cooperative sites corresponded to measureable improvements in the reliability of the service they provide to their members, reliability metrics must be analyzed from both before and after the improvements were made. Table 10.3 presents a summary of these indices for affected feeders from September 1, 2011 to October 16, 2013. These indices were calculated by the utility. The metrics, while interesting, do not facilitate the comparison that was desired. The index "Average Service Availability Index" in this table is the average availability of service—the fraction of the year that remains after the System Average Interruption Duration Index duration has been removed.

Table 10.3. Reliability Indices for Affected Flathead Electric Cooperative Feeders from September 1, 2011 to October 16, 2013

Feeder	ASAI (%)	CAIDI (minutes/outage)	SAIDI (minutes/year)	SAIFI (outages/year)
Kootenai T2091	99.97	187	385	2.06
Kootenai T2092	99.97	85	377	4.43
Libby T1205	99.99	92	145	1.57
Libby T3667	99.99	90	66	0.73
Haskill T1695	99.86	143	1,538	10.77
Haskill T2093	99.93	132	739	5.59

ASAI = Average Service Availability Index
CAIDI = Customer Average Interruption Duration Index
SAIFI = System Average Interruption Frequency Index

Table 10.4 provides a detailed analysis of the causes of the outages during the same time period that was covered by Table 10.3. This analysis was compiled by the utility.

Table 10.4. Counts and Causes of Feeder Outages from September 1, 2011 to October 16, 2013

Substation / Metric	Power Supply	Planned Outage	Equipment Installation Design	Maint.	Weather	Animals	Public	Other	Unknown	Substation Total
Kootenai T2091										
Outages	0	4	1	1	0	3	0	0	1	**10**
Customers Out	0	20	2	3	0	196	0	0	51	**272**
Cust. Minutes	0	1,923	126	138	0	43,025	0	0	5,610	**50,822**
Kootenai T2092										
Outages	0	64	28	34	12	22	5	1	15	**181**
Customers Out	0	593	2,997	4,927	671	1,200	24	2	853	**11,267**
Cust. Minutes	0	29,930	153,050	607,811	47,358	13,374	1,431	116	106,625	**959,695**
Libby T1205										
Outages	0	43	11	16	7	33	4	2	8	**124**
Customers Out	0	395	303	495	263	255	55	28	84	**1,878**
Cust. Minutes	0	12,234	28,250	59,538	31,449	23,400	5,187	2,305	10,225	**172,588**
Libby T3667										
Outages	0	37	14	4	5	16	3	3	7	**89**
Customers Out	0	110	80	212	208	294	9	11	314	**1,238**
Cust. Minutes	0	6,899	7,266	16,822	20,178	16,920	732	1,717	40,357	**110,891**
Haskill T1695										
Outages	1	49	14	29	9	6	3	0	7	**118**
Customers Out	913	606	1,667	5,901	987	80	970	0	380	**11,504**
Cust. Minutes	17,347	42,631	234,055	931,112	292,921	7,151	83,443	0	33,526	**1,642,186**
Haskill T2093										
Outages	1	41	19	44	18	4	8	1	11	**147**
Customers Out	1,347	794	121	3,650	1,333	36	177	7	82	**7,547**
Cust. Minutes	25,593	68,782	18,701	570,729	235,928	3,685	59,921	1,477	13,349	**998,165**

10.2 In-Home Displays

Flathead Electric Cooperative next considered the incremental costs and benefits available from Aclara TWACS in-home displays (see Figure 10.4). These devices were easily provided to and installed by cooperative members. Members simply plugged the devices into a wall socket at their premises. The in-home displays communicate using the power-line-carrier communication system of the installed advanced metering at each premises. These devices were intended to display general information from the cooperative about the utility and project, and to emit an audible alarm and display the message "Peak Time" on their light-emitting diode screens during peak periods. Members, upon receiving this Peak Time message and its alarms and indicators, were expected to manually curtail their electricity use. A monthly credit (~$5 per month) and annual rebate based on peak period reductions were provided to cooperative members who accepted and used the in-home displays.

This test was halted by Flathead Electric Cooperative after only one year of operation. The cooperative believed that the audible alarms being emitted by the in-home displays were annoying to participating members. This annoyance was further increased by the challenges that the project encountered as it automated the transactive system events. The project initially misconfigured the automation of assets' responses to the transactive system, and it took months for project participants to identify and correct the assets' misconfigurations. Furthermore, the incentive signals generated by the project to engage distribution systems like the in-home displays took many months to correct. For example, a persistent system design problem caused the transactive system to at first invite assets to participate in erroneous "midnight" events. That was unfortunate.

Regardless, the performance and benefit of the in-home displays were evaluated by the project for the limited number of events that the in-home displays were allowed to operate. The project reviewed premises data supplied by Flathead Electric Cooperative and evaluated energy usage during events, after events, and during event days.

Figure 10.4. Aclara Model 110 In-Home Display of the Type Used by the Flathead Electric Cooperative Peak Time Project[1]

The annualized costs of the two sites' in-home display systems are summarized in Table 10.5 (Libby, Montana site) and Table 10.6 (Marion/Kila, Montana site) below. The entire annualized cost of the system in Libby was estimated as $113,500, and that at Marion/Kila was estimated as $102,800. Annualized system component costs are dominated by the costs of software, utility staff labor, and incentives. The systems also include a fraction of the TWACS communication substation components and a fraction of the cost of AMI. The 50-percent allocation of the cost of in-home displays refers to the split of that hardware cost between the Libby (Table 10.5) and Marion/Kila (Table 10.6) sites. Had the system of in-home displays not shared some of the component allocations with other of the cooperative's asset systems, the costs would have been greater.

[1] Flathead Electric Cooperative, Inc. (FEC). 2013. Flathead Electric Cooperative Demonstration Project: Peak Time. Unpublished slide presentation file Peak_Presentation_2013.pptx, February 2013.

Table 10.5. Incremental Annualized Costs of Installing and Operating 90 In-Home Displays at the Libby, Montana, Site

	Shared Component Allocation (%)	Annualized Component Cost ($K)	Allocated Annual Component Cost ($K)	
Integration Software	17	293.6	49.0	
Staff Support	13	293.1	36.6	
Incentives	100	20.5	20.5	
In-Home Displays (Model 110)	50	6.4	3.2	
Back-End Metering	13	11.7	1.5	
Substation TWACS Components			0.9	
• Modulation Transfer Unit (Model Y87363)	25	1.4		0.3
• Inbound Pickup Unit (Model Y83760)	25	0.3		0.1
• Outbound Modulation Unit (Model 303)	25	1.3		0.3
• Control/Receiving Unit (Model 627)	25	0.9		0.2
Group-B Single-Phase Meters	50	1.5	0.7	
Meters Operations and Maintenance	25	2.4	0.6	
Demand-Response Software	33	1.1	0.4	
Total Annualized Asset Cost			**$113.5K**	

Table 10.6. Incremental Annualized Costs of Installing and Operating 12 In-Home Displays at the Marion/Kila, Montana, Site

	Shared Component Allocation (%)	Annualized Component Cost ($K)	Allocated Annual Component Cost ($K)	
Integration Software	17	293.6	49.0	
Staff Support	13	293.1	36.6	
Incentives	100	10.3	10.3	
In-Home Displays (Model 110)	50	6.4	3.2	
Back-End Metering	13	11.7	1.5	
Group-B Single-Phase Meters	50	1.5	0.7	
Meter Operations and Maintenance	25	2.4	0.6	
Substation TWACS Components			0.5	
• Modulation Transfer Unit (Model Y87362)	25	0.7		0.2
• Inbound Pickup Unit (Model Y83765)	25	0.2		0.0
• Outbound Modulation Unit (Model 303)	25	0.7		0.2
• Control/Receiving Unit (Model 627)	25	0.4		0.1
Demand-Response Software	33	1.1	0.4	
Total Annualized Asset Cost			**$102.8K**	

It is very challenging to predict voluntary responses that will be offered by cooperative members. Unknowable conditions affect the willingness of members to respond to a given event. The overall willingness of members to respond may be influenced by the timing of educational information supplied from the cooperative. The project was able to marginally confirm members' responsiveness at the Libby site, but little can be confidently said about the rural Marion/Kila site, which had few participating residences.

10.2.1 Characterization of In-Home Display System Responses

The starting times and durations of Peak Time in-home display events are shown in Table 10.7 (Libby site) and Table 10.8 (Marion/Kila site). The hours are stated in local Mountain Time. The in-home display program was halted in Libby after only four Peak Time events that occurred from February through September 2013. An additional three events were allowed through March 2014 at the Marion/Kila site. The events were all between 2 and 3 hours long. These events that are understood to have been sent by the utility to the in-home displays at the two sites will be referred to as the Peak Time events, regardless whether they coincided with utility peak load.

After reviewing the project's analysis, the utility noted a couple discrepancies between their records of event times and the times that had been reported into the project's database. For example, the first events at both sites failed, and the Peak Time messages had not, in fact, reached the targeted in-home displays. The utility reported that Event 5 at the Marion/Kila site had begun at 06:55, but the project's records had shown the event to have begun at 12:55 that day.

The cooperative provided to the project a list of their actual monthly peak-demand hours from October 2012 until the demonstration project ended. Only one Peak Time event at the two sites coincided with an actual month's peak-demand hour—equivalent to 25% of the Libby events and 14% of the Marion/Kila events. Seventy-eight percent of the total Peak Time event durations at Libby and 78% of those at Marion/Kila occurred during Bonneville Power Administration (BPA) heavy-load hours (HLHs).

Table 10.7. Starting Times and Durations of the Libby, Montana, In-Home Display Peak-Time Events

Event	Year	Month	Day	Weekday	Hour	Minute	Length (h:m)
1[(a)]	2013	2	28	Thursday	6	50	2:20
2[(b)]	2013	3	5	Tuesday	6	50	2:10
3[(c)]	2013	8	15	Thursday	9	20	2:10
4	2013	9	2	Monday	19	0	2:00

(a) Flathead Electric said this was a manual event that was dispatched by them but failed to reach any of the in-home displays.
(b) Coincided with a Flathead Electric Cooperative monthly peak-demand hour.
(c) Coincided with an advised transactive system event for this asset system.

Table 10.8. Starting Times and Durations of the Marion/Kila, Montana, In-Home Display Peak-Time Events

Event	Year	Month	Day	Weekday	Hour	Minute	Length (h:m)
1[(a)]	2013	2	28	Thursday	6	50	2:20
2[(b)]	2013	3	5	Tuesday	6	50	2:10
3[(c)]	2013	8	15	Thursday	9	20	2:10
4	2013	9	2	Monday	22	15	2:45
5[(d)]	2013	9	18	Wednesday	06	55	2:05
6[(a,c)]	2014	1	30	Thursday	9	30	2:00
7[(a.c)]	2014	2	11	Tuesday	9	0	2:00

(a) Flathead Electric Cooperative later stated that this event, which was included in project analysis, had been dispatched by the utility but failed to reach the in-home displays.
(b) Coincided with an actual Flathead Electric Cooperative monthly peak-demand hour.
(c) Coincided with an advised transactive system event for this asset system.
(d) There was a discrepancy in the timing of this event. Flathead Electric says that event ran from 06:55 to 09:00. Analysis was conducted from data that said the event ran from 12:55 to 15:00. The cause of the discrepancy is unknown.

There were altogether 56 events advised by the transactive system for the in-home displays at the Libby site from February 2013 through August 2014. Only one of the four Peak Time events of Table 10.7 coincided with one of the 56 advised transactive events. Three of the seven (43%) Peak Time events at the Marion/Kila site overlapped with advised transactive system events. The advised transactive events never, in fact, coincided with the cooperative’s actual monthly peak-demand hours. Sixty-seven percent of the advised transactive event hours were during BPA HLHs. While 70% of the advised transactive events were precisely 2 hours long, the other events ranged from 1 hour long to almost 9 hours long. The longest events tended to occur early in the demonstration while the transactive system function for this asset system remained poorly configured.

The days on which transactive events were advised for the systems of in-home displays are shown by Figure 10.5. Early misconfiguration of the assets’ responses accounted for the many weekend events, which never have HLHs and would typically not benefit the cooperative.

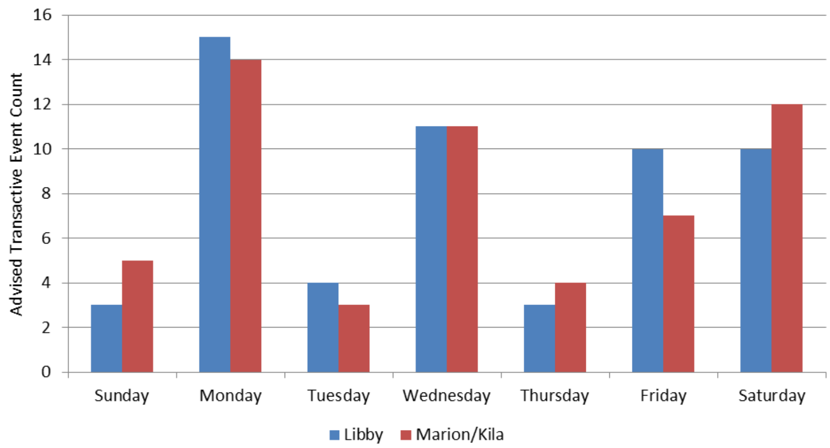

Figure 10.5. Week Days on which Transactive Events were Advised to the In-Home Displays

The starting hours on which the transactive events were advised for in-home displays at the two sites are summarized in Figure 10.6. The cooperative would be unlikely to deploy any assets for peak reduction during off-peak hours, but transactive signals were regionally focused. It was plausible that the transactive system's incentives might occur during off-peak hours. The events were eventually called during reasonable morning and afternoon hours, when they were likely to help reduce peak demand. Early on, the transactive incentive signals had suffered from a persistent prediction error that invited many erroneous late evening, early morning, and weekend events that are shown here.

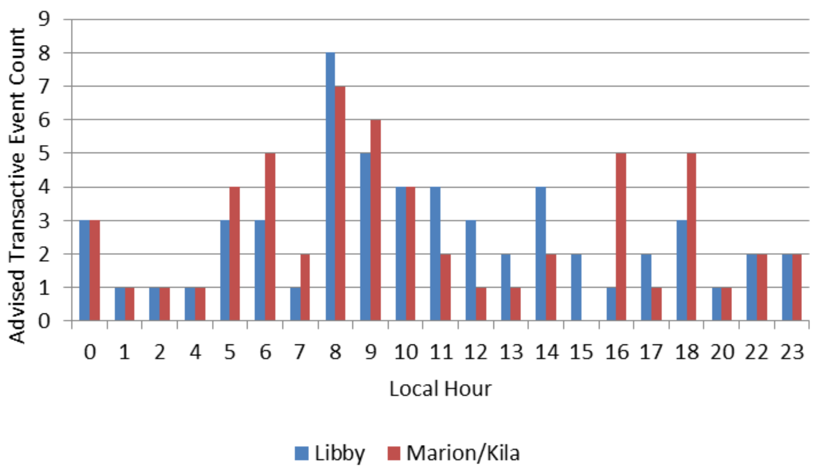

Figure 10.6. Hours on which Transactive Events were Advised for the In-Home Displays

Starting with August 2011, the test population of Libby in-home display premises was defined and remained consistent throughout the project. The typical number of in-home display participants in Libby was about 83. The count varied from about 65 to 90 on an averaged monthly basis. The recruitment of one hundred participants had been the cooperative's goal.

The Marion/Kila test population ranged from 8 to 12 members from January 2012 through August 2014.

10.2.2 In-Home Display System Performance

The project attempted to confirm impacts from the in-home display Peak Time events. Two baseline comparison approaches were used and compared—modeled and controlled. The baselines emulate data that is unaffected by in-home displays. The words "modeled" and "controlled" refer to the methods by which the baselines were constructed.

Modeled baseline. In the first, a linear model of the averaged premises power for each site's test population was constructed using R statistical software (R Core Team 2013). Using regression methods, the average premises power of the test group was modeled as a function of temperature, evaluated separately by calendar month, day of week, and hour of day. A modeled baseline time series was then constructed from this linear model for comparison against the raw time-series data to determine whether the load was measurably affected during events, after events, and during event days.

Controlled baseline. The controlled baseline was constructed using a control group by scaling the average power from a comparable set of Group-A premises that had not been given in-home displays and was not informed about Peak Time events. By observation, the raw power data from the Group-A time series had a lower average load, suggesting that there was perhaps a selection bias between the two populations. The Group-A time series was scaled to have the same mean and standard deviation as the data from the test population on a month-by-month basis. Noting that the two populations still exhibited different hourly consumption patterns, the Group-A time series was further globally corrected on an hourly basis to have the same average hourly consumption as the test population.

Figure 10.7 may be useful to explain the project's method for comparing time series against either baseline. In this example, the averaged 5-minute premises loads for Libby members who had in-home displays is plotted against similar 5-minute intervals that were created from the modeled baseline. If the baseline were perfect, then all the points would align perfectly on a line having unity slope. However, baseline inadequacies and natural load variability conspire to make the baseline diverge from the time-series data that it attempts to emulate. On average, however, the difference between the time-series data and its baseline is about zero.

Peak Time event data have been shaded red in Figure 10.7. The question posed by analysts is, is the difference between the experimental population and its baseline significantly different between event periods and non-event periods? The figure includes linear best fits of the Peak Time data (red) and from non-event periods (blue). The two sets of will be compared to estimate the mean difference, standard error (that is, the interval within which about 68% of differences would be expected to fall), and a 95% confidence interval. While these methods might yield results for even very small data sets, we will try not to overstate the significance of such results, which can be misleading.

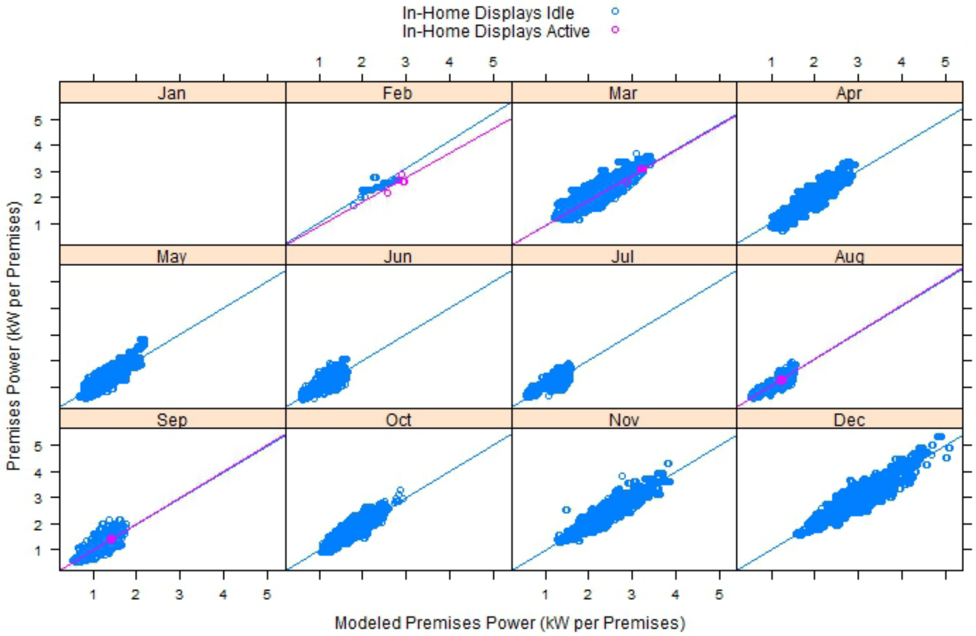

Figure 10.7. Averaged Load for Libby, Montana, Premises that have In-Home Displays Plotted against a Modeled Baseline of this Same Data for the Months of 2013. Data from Peak Time event periods are colored red.

The project will refer to these confidence intervals as *estimates* because they are adopted from statistical practices that are intended for statistically normal populations and independent observations. The project cannot assert that the small populations of differences have Gaussian distributions or that the data observations are entirely independent.

A load reduction may be reported for all on-peak and off-peak Peak Time events in Libby, as shown in Figure 10.8. The far right-hand side of this figure shows a statistical result for all the Libby Peak Time event periods. Using the modeled baseline (blue), there is a 94% likelihood that consumption was, in fact, reduced during events at Libby premises that have in-home displays, and the reduction is about 80 ± 50 W per premises. Using the controlled baseline population (black), there is 91% likelihood that power consumption was reduced in the homes with in-home displays during Libby events, and the reduction was 190 ± 140 W. The average of the results from both baseline approaches is a reduction of 140 ± 80 W per premises during the Peak Time events for those premises that had in-home displays.

The monthly results from the modeled baseline are shown slightly offset to the left of the month and the controlled baseline result is offset to the right. Individual months' results at Libby should be used cautiously because each month had few independent, hourly Peak Time measurements. However, some of the greatest impacts appear to have occurred when the program was new, suggesting that cooperative members were affected by the novelty of the device and by the education that they received from the cooperative at the beginning of the Peak Time program. One hypothesis is therefore that member enthusiasm waned rapidly with time. Alternative explanations include measurement clock errors and miscalibrations that would appear to soften the aggregated result or even cause the project to seek the result at the wrong times.

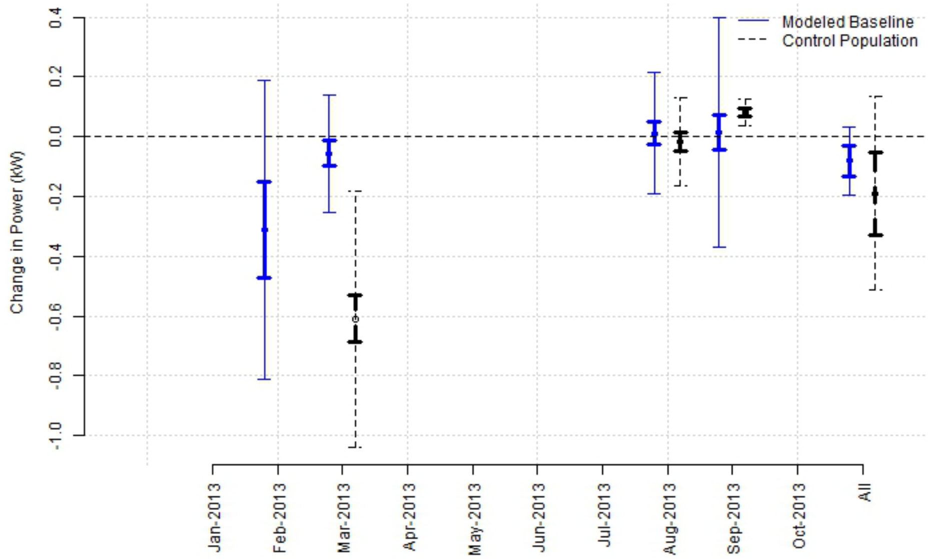

Figure 10.8. Measured Change in Power per Premises during Libby, Montana In-Home Display Peak-Time Events. Ranges include standard errors (bold bars) and 95% confidence intervals (thin bars). Blue results are from the modeled baseline and black dashed results used the controlled baseline.

During events at the Marion/Kila site, no significant reduction in member load can be reported. Both baseline methods suggested an *increase* in load had accompanied the in-home display events there, but statistical confidence was low. There were too few test premises and too few events at the Marion/Kila site to obtain significant analysis results.

A similar analysis was conducted to look at the hour immediately following Peak Time events to determine whether any rebound effect can be observed after in-home display events are terminated. Figure 10.9 shows the averaged results by month while using the modeled baseline (blue, offset just left of the corresponding month) and controlled baseline (black, offset just right of the corresponding month). The results from using all Peak Time data are shown on the far right.

Using the modeled baseline (blue in Figure 10.9), a *reduction* of about 130 ± 70 W per premises may be reported for the hour following events in Libby with 95% confidence that a reduction occurred. Using the controlled baseline approach, a similar load reduction was suggested (180 ± 160 W) (black in Figure 10.9) for Libby, but there is only about an 86% confidence that any reduction occurred. The average of the results from the two baselines is a reduction of 160 ± 90 W per premises that had in-home displays during the rebound hours following Peak Time events at the Libby, Montana, site.

This is not a typical rebound impact in that continued load *reduction* was observed rather than an *increase* in load that is typical for most demand-response systems. The demand reduction in the hour following events might be even greater than the reduction during events. In-home displays appear to induce voluntary responses that may have lingering impacts even after an event has ended.

No standard errors or confidence intervals appear for the individual months in Figure 10.9 because the number of measurements was insufficient to calculate and state such intervals.

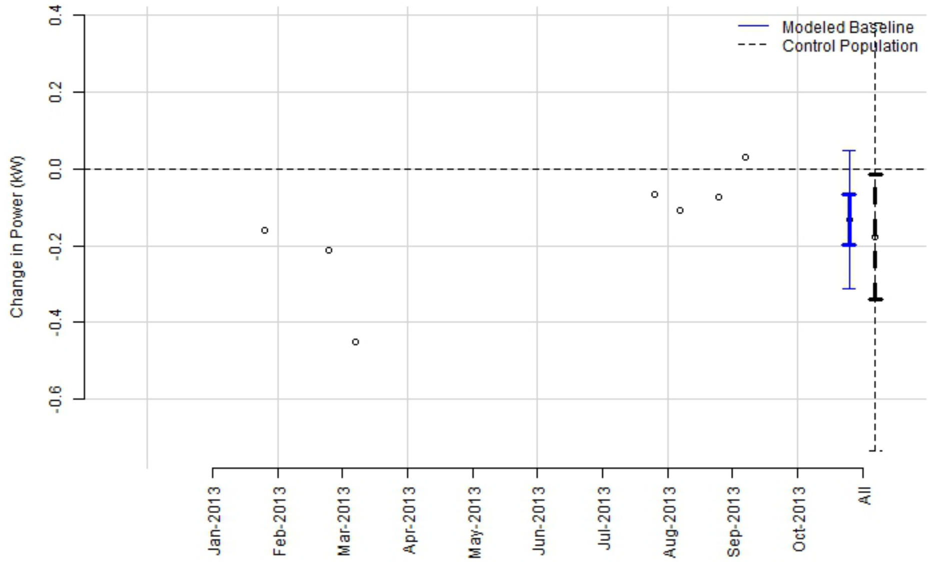

Figure 10.9. Measured Impact per Premises during Rebound Hours for Libby, Montana Premises having In-Home Displays Using the Modeled (blue) and Controlled (black) Baselines

Inconclusive results were observed during the rebound hours at the Marion/Kila site (not shown). Both baselines suggested that an increase in load might have occurred during rebound hours, but the project's confidence is low that the increase is real.

The project additionally compared the entire days on which events had and had not occurred. A surprising finding was that both baselines suggested that significant reductions occurred the entire day of the Peak Time events. Figure 10.10 summarizes impacts at the Libby site during Peak Time event days. Using the modeled baseline, there is a 90% likelihood that a reduction occurred at premises having in-home displays, and the average reduction was 20 ± 20 W per premises throughout the days of the events. The controlled baseline yielded even stronger confidence that the days' premises loads had diminished for those in Libby who had been notified via their in-home displays, and the average reduction was 60 ± 20 W.

The voluntary responses by in-home display owners extended through the entire event day, not just through the limited event duration. The members were more responsive to the March 2013 event than to events later in the program. The average of the results from the two baselines at Libby is a reduction of 40 ± 30 W per premises throughout days that Peak Time events had occurred.

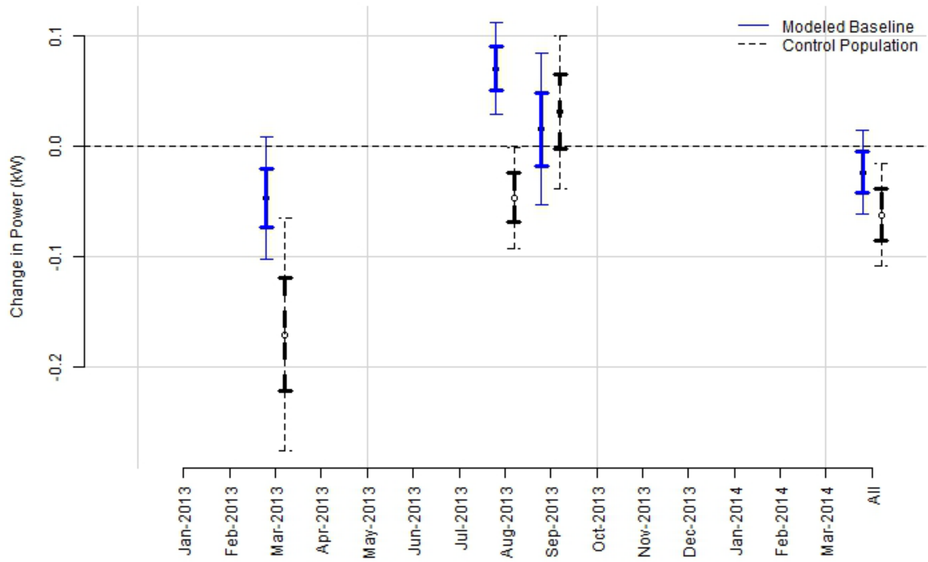

Figure 10.10. Measured Average Impact per Premises during Peak-Time Event Days for Libby, Montana Premises having In-Home Displays Using the Modeled (blue) and Controlled (black) Baselines

At the Marion/Kila site, using the modeled baseline, member premises used an average 30 ± 30 W less power during event days than during non-event days (Figure 10.11). The confidence that any reduction occurred was about 98%. A similar reduction was suggested by the controlled baseline, but the likelihood of the reduction cannot be stated with confidence. The averaged result from the two baseline approaches was a reduction of 20 ± 20 W per in-home display premises throughout the days that had Peak Time events at the Marion/Kila site.

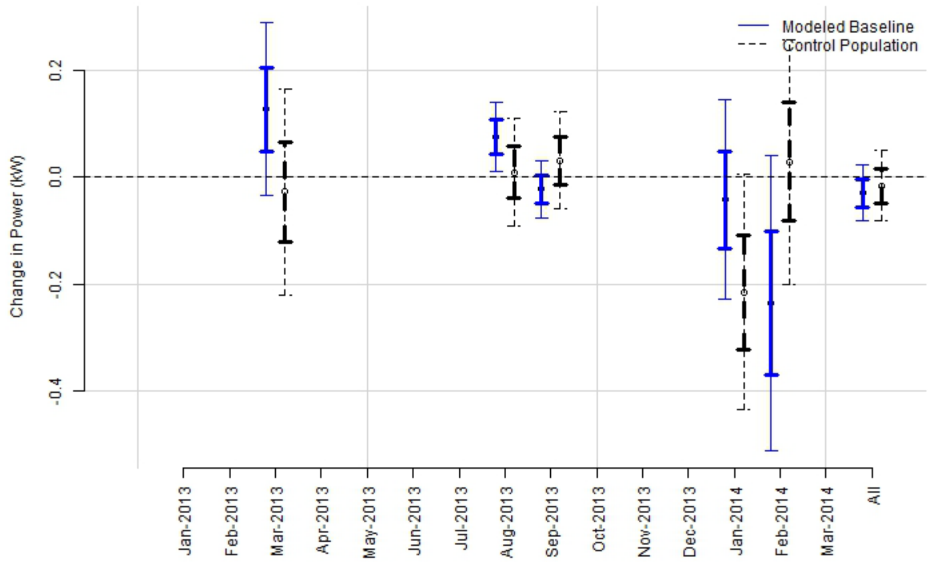

Figure 10.11. Measured Average Impact per Premises during Event Days for Marion/Kila, Montana Premises having In-Home Displays Using the Modeled (blue) and Controlled (black) Baselines

The project next estimated the value of the energy that was displaced as the system of in-home displays responded to Peak Time events. Flathead Electric Cooperative is a BPA supply customer, so the value of energy supply may be based on BPA's unit energy costs for heavy-load and light-load (LLH) hours. See Appendix C for additional detail about BPA's tiered rate methodology.

First, a table was created to compile the average differences between the Libby test group's average premises power and the modeled baseline that was created from the Libby test group power data. The differences were created for each calendar month and separately for HLHs and LLHs. This table provided the project a statistical estimate of the impacts by these hour types and months, including estimates of the standard deviations between the data and baseline. Then, the durations of the Peak Time events within HLH and LLH types was used to estimate the total energy and costs impacts.

Table 10.9 summarizes these estimates. Because there were few events, this benefit could be assessed only three calendar months. The value of the curtailed energy was miniscule. Even if the results from the active months were extrapolated to all the calendar months, the value of the displaced energy supply is only a couple dollars.

Table 10.9. Estimated Energy Curtailed by In-Home Display Premises each Calendar Month and the Supply Value of that Energy as the In-home Display Premises Responded to Peak Time Events

	HLH		LLH		Total	
	(kWh)	($)	(kWh)	($)	(kWh)	($)
…	-	-	-	-	-	-
Mar	−33 ± 2	−0.7 ± 0.0	-	-	−33 ± 2	−0.7 ± 0.0
…	-	-	-	-	-	-
Aug	2 ± 1	0.0 ± 0.0	-	-	2 ± 1	0.0 ± 0.0
Sep	-	-	9 ± 2	0.23 ± 0.06	9 ± 2	0.2 ± 0.1
…	-	-	-	-	-	-

Analysis was conducted to estimate the potential impact of the Libby in-home display system on the utility's demand charges that are imposed on it as a customer of BPA. One of the components of the demand charges calculation is the change in average HLH energy. As was shown in the discussion about energy impacts, the system's impact on the HLH energy, and therefore its impact on average HLH energy, was negligible.

A table of impacts was generated for each calendar month and by HLH hour. Only HLH hours were considered because demand charges may be incurred only during those hours. This table estimates the statistical average by HLH hour each month, and the table included the standard deviations that were useful toward understanding the variability of the impacts. Then, this table was compared against a list of the utility's historical monthly peak hours. If the month's historical peak hours never coincided with the hours that Peak Time events were, in fact, called in a month, the utility was given no credit for changing its demand charges. If, however, the Peak Time events were demonstrated to have occurred during one or more of the historical peak hours in a given month, the estimated impact was estimated proportionate to the numbers of times that the hours were coincident.

This method of estimation will be somewhat optimistic because it presumes that the Peak Time events will be skillfully applied on the exact day that the monthly peak occurs. Had the project given credit for changing demand charges only if the hour and the day in a given month had coincided with the actual month's peak, the estimated impact on demand charges would have been even smaller, and the project would have been unable to apply any estimate of statistical variability of the impact.

The method of estimation is also affected by the scale of the demonstration. Libby had installed up to about 90 in-home displays. The impact should be expected to scale pretty linearly with the numbers of installations.

Table 10.10 summarizes the impact that the system of Libby in-home displays might have on typical demand charges each calendar month. The system had been shown to insignificantly affect the average HLH load during a March and August. The timing of the demonstrated Peak Time event in March coincided with historical March peak hours. If the system were to perform every month as it did in March, the project extrapolates that the utility might reduce its yearly demand charges by about $3,500.

Table 10.10. Estimated Impact of the System of Libby In-Home Displays on the Demand Charges that are Incurred each Month by Flathead Electric Cooperative

	Δ Demand (kW)	Δ aHLH (kWh/h)	Δ Demand Charges ($)
…	-	-	-
Mar	−30 ± 1	~0	−290 ± 1
…	-	-	-
Aug	0	~0	~0
…	-	-	-

While looking at energy supply costs and impacts on demand charges, the project used only the demonstrated changes in power during events. The project did not explicitly consider the potential impacts of rebounds hours or event-day impacts on the costs.

10.3 DRUs

Flathead Electric Cooperative members who possessed advanced interval meters were candidates to participate in Group C, for which Aclara DRUs were installed to control residential electric water heaters See Figure 10.12. These devices communicate via the existing TWACS power-line-carrier system, and the cooperative could send a command to water heater DRUs to curtail water the heaters’ electric load. Participating Group-C members who accepted the water heater DRUs received a monthly participation credit (~$8/month) on their monthly bills.

Figure 10.12. Aclara TWACS DRU that was Used to Cycle Water Heaters in the Flathead Electric Cooperative Peak-Time Project[1]

The benefit of the TWACS DRU technology versus the cost of providing it was to be evaluated by comparing incremental costs and benefits for the premises that accept DRUs against those that have only AMI. Table 10.11 summarizes the annualized system costs at the Libby site, and Table 10.12 summarizes the annualized system costs at the Marion/Kila site. The systems, of course, include the DRUs that are allocated between the two sites. The annualized system costs also include some of the shared costs of substation TWACS components, the metering systems, metering operations, demand-response software, and member incentives. The total annualized cost of the Libby DRU system was $113,000, and that of the Marion/Kila system was $104,900.

[1] Ibid.

Table 10.11. Flathead Electric Incremental Costs of DRUs at the Libby Site

	Shared Component Allocation (%)	Annualized Component Cost ($K)	Allocated Annual Component Cost ($K)	
Integration Software	17	293.6	49.0	
Staff Support	13	293.1	36.6	
Incentives	100	15.0	15.0	
DRU (two-way)	50	16.2	8.1	
Back-End Metering	13	11.7	1.5	
Substation TWACS Components			0.9	
• Modulation Transfer Unit (Model Y87363)	25	1.4		0.3
• Inbound Pickup Unit (Model Y83760)	25	0.3		0.1
• Outbound Modulation Unit (Model 303)	25	1.3		0.3
• Control/Receiving Unit (Model 627)	25	0.9		0.2
Group-C Single-Phase Meters	50	1.5	0.7	
Meter Operations and Maintenance	25	2.4	0.6	
Demand-Response Software	33	1.1	0.4	
Total Annualized Asset Cost			**$113.0K**	

Table 10.12. Flathead Electric Incremental Costs of DRUs at the Marion/Kila Site

	Shared Component Allocation (%)	Annualized Component Cost ($K)	Allocated Annual Component Cost ($K)	
Integration Software	17	293.6	49.0	
Staff Support	13	293.1	36.6	
DRU (two-way)	50	16.2	8.1	
Member Incentives	100	7.5	7.5	
Back-End Metering	13	11.7	1.5	
Group-C Single-Phase Meters	50	1.5	0.7	
Meter Operations and Maintenance	25	2.4	0.6	
Substation TWACS Components			0.5	
• Modulation Transfer Unit (Model Y87362)	25	0.7		0.2
• Inbound Pickup Unit (Model Y83765)	25	0.2		0.0
• Outbound Modulation Unit (Model 303)	25	0.7		0.2
• Control/Receiving Unit (Model 627)	25	0.4		0.1
Demand-Response Software	33	1.1	0.4	
Total Annualized Asset Cost			**$104.9K**	

10.3.1 Characterization of DRU System Responses

The number of members in the DRU Group-C test population at the Libby site ranged from 85 to 92 over the three years from August 2011 through August 2014. At Marion/Kila, the member count grew slowly and ranged from 15 to 21 from February 2012 through August 2014.

The cooperative provided the project with lists of the events that it initiated for this asset system, and these lists are reproduced here as Table 10.13 and Table 10.14. In the remainder of discussion about DRUs in this chapter, the events in these lists will be referred to as Peak Time events. There were 19 events called at Libby and 20 at Marion/Kila during the 19 months that this asset system was operated during the project. These listed events coincided only once (~6%) with actual monthly peak-demand hours at each of the two sites. Peak Time events overlapped advised transactive system events for this asset system 47% of the time at Libby and 60% of the time at the Marion/Kila site.

Two-thirds of the total Peak Time event durations at both sites occurred during BPA HLHs. The ratio was almost identical for events that had been advised to the DRUs by the transactive system (68% for Libby and 64% for Marion/Kila).

All of the Peak Time events were between 2 and 3 hours long.

Table 10.13. DRU Peak-Time Event Starting Times and Durations at the Libby Site

Event	Year	Month	Day	Weekday	Hour	Minute	Length (h:m)
1	2013	2	28	Thursday	6	50	2:20
2	2013	3	5	Tuesday	6	50	2:10
3[c]	2013	8	15	Thursday	9	20	2:10
4	2013	9	2	Monday	19	0	2:00
5	2013	9	18	Wednesday	12	55	2:05
6[a,c]	2013	12	9	Monday	18	0	2:00
7	2014	2	10	Monday	17	30	2:00
8[b,c]	2014	2	11	Tuesday	9	0	2:00
9	2014	3	3	Monday	06	55	2:00
10[c]	2014	4	29	Tuesday	08	0	2:00
11[c]	2014	5	15	Thursday	09	45	2:00
12[c]	2014	6	10	Tuesday	10	25	2:05
13[c]	2014	6	12	Thursday	10	0	2:00
14[c]	2014	7	1	Tuesday	11	40	2:05
15[c]	2014	7	14	Monday	13	20	2:10
16	2014	7	16	Wednesday	16	0	3:00
17	2014	8	1	Friday	13	30	2:00
18	2014	8	1	Friday	17	0	2:00
19	2014	8	4	Monday	16	0	3:00

(a) This event was dispatched by the transactive system but was cancelled and not acted upon by the Flathead Electric Cooperative.
(b) The utility, upon review, had no record of this event having occurred.
(c) Coincided with an advised transactive system event for this asset system.

Table 10.14. DRU Peak-Time Event Starting Times and Durations at the Marion/Kila Site

Event	Year	Month	Day	Weekday	Hour	Minute	Length (h:m)
1	2013	2	28	Thursday	6	50	2:20
2	2013	3	5	Tuesday	6	50	2:10
3[a]	2013	8	15	Thursday	9	20	2:10
4	2013	9	2	Monday	22	15	2:45
5	2013	9	18	Wednesday	12	55	2:05
6[a]	2013	12	9	Monday	18	0	2:00
7[a]	2014	1	30	Thursday	9	30	2:00
8	2014	2	6	Thursday	6	55	3:00
9[a]	2014	2	10	Monday	17	30	2:00
10[a]	2014	2	11	Tuesday	9	0	2:00
11[a]	2014	4	29	Tuesday	8	0	2:00
12[a]	2014	5	15	Thursday	9	45	2:00
13[a]	2014	6	10	Tuesday	10	25	2:05
14[a]	2014	6	12	Thursday	10	0	2:00
15[a]	2014	7	1	Tuesday	11	40	2:05
16[a]	2014	7	14	Monday	13	20	2:10
17	2014	7	16	Wednesday	16	0	3:00
18[a]	2014	8	1	Friday	13	30	2:00
19	2014	8	1	Friday	17	0	2:00
20	2014	8	4	Monday	16	0	3:00

(a) Coincided with an advised transactive system event for this asset system.

The project's transactive system advised 58 transactive events at the Libby site and 59 at the Marion/Kila site. The advised transactive event durations ranged from 50 minutes to 4 hours and 10 minutes. The advised transactive events never coincided during the project with either the listed Peak Time events or the actual monthly peak-demand hours for this asset system. Regardless, the next couple paragraphs will address some characteristics of the transactive events even though the Peak Time events were found to not have been coincident.

The weekdays of the advised transactive system events at the two sites for this asset system are shown in Figure 10.13. The weekend events transactive system events were ill-advised early in the project before the advising toolkit function had been thoroughly configured. The cooperative would unlikely desire curtailment events on Sundays and other off-peak hours because it receives no compensation for reducing peak demand during BPA lightly loaded hours.

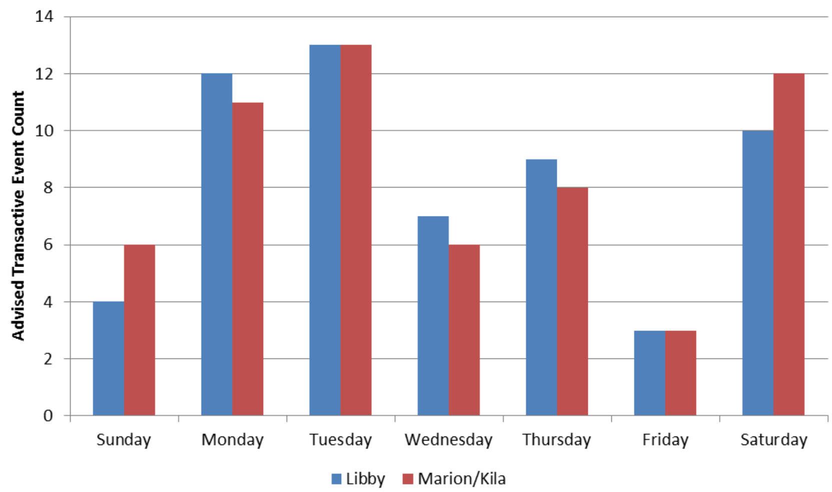

Figure 10.13. Days of Week on which Transactive Events Were Advised for the Libby and Marion/Kila DRUs

Figure 10.14 shows the starting hours (local Mountain Time) of the advised transactive system events at the two sites for this asset system. The late night and very early morning events resulted partly from the misconfigured advising function and partly from an erroneous incentive function early in the project that incentivized responses at such times.

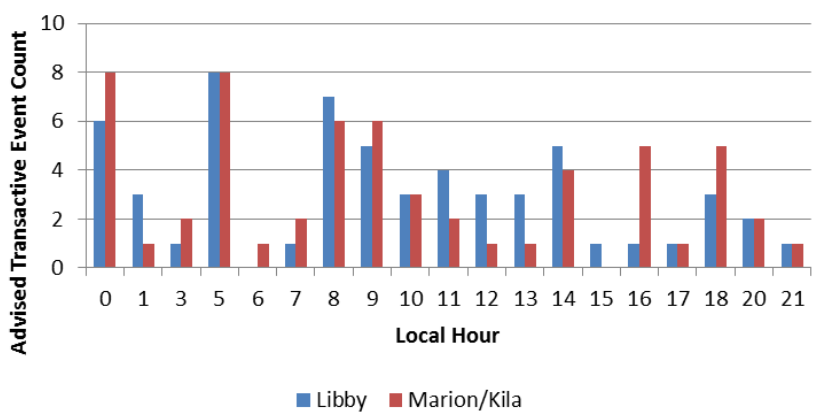

Figure 10.14. Local Starting Hours of the Advised Transactive Events for the Libby and Marion/Kila DRUs

10.3.2 DRU System Performance

The analysis for DRUs was very much like that used for the Flathead Electric Cooperative in-home displays (Section 10.1). Again, two baselines were created to emulate average premises power unaffected by the DRUs.

Controlled baseline. The controlled baseline was based on averaged hourly power from nearby Group-A premises. The data from this control group was scaled each month to have the same average and standard deviation as the premises that had DRUs controlling their water heaters. Additional global corrections were made to improve the comparison between hourly power profiles.

Modeled baseline. To create the modeled baseline, a linear regression was performed to model power consumption at times the power should not have been affected by Peak Time events as a function of ambient temperature and by month, hour, and day of week. The quality of these models was assessed by reviewing their residuals.

Several figures will now be presented to show the average difference between the baseline and test data. The results further take into account the differences between the baselines and test data both when Peak Time events were active and when they were not. The analysis was based on a Student’s t-test, treating the differences between the baselines and test data as independent sets.

Figure 10.15 addresses the impact of DRU curtailment per premises at the Libby site. Impacts from Peak Time event periods are being compared to those when no events were active, which are expected to be near zero. The results using the modeled baseline for comparison (blue) are shown offset to the left of the corresponding month, and results from the controlled baseline (black) are offset to the right of the corresponding month. The aggregate results from all Peak Time periods are shown to the far right labeled “All.”

The results are consistently negative, indicating that a *reduction* in load was consistently observed during events at homes that had DRUs. Based on the modeled baseline, the reduction was 226 ± 41 W per premises. A similar impact was estimated using the controlled baseline— a reduction of 252 ± 39 W per premises. The average of the analyses from both baselines is a reduction of 239 ± 28 W.

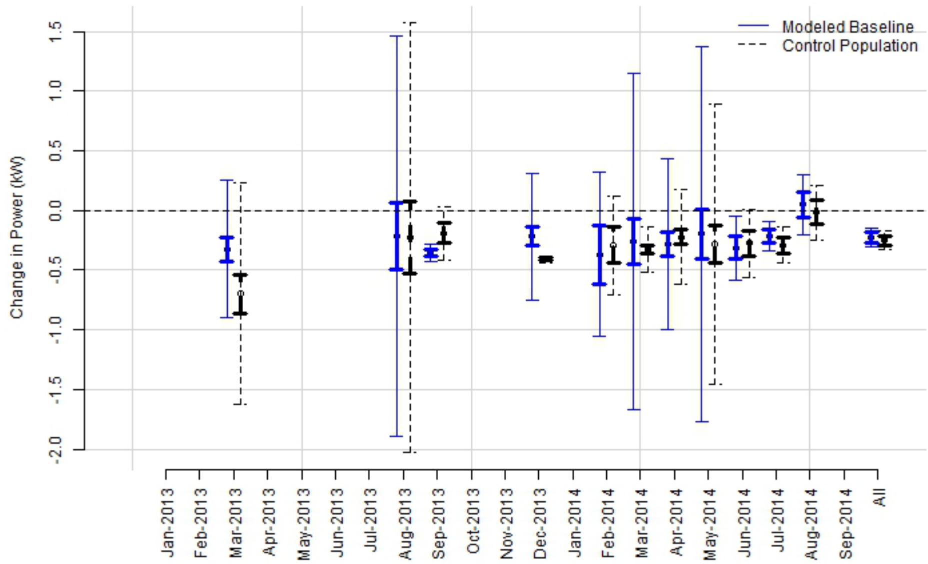

Figure 10.15. Average Impact of DRUs during Peak Time Events by Month at the Libby Site Using the Modeled (blue) and Controlled (black) Baselines

Similar results were found for the impact of DRUs during Peak Time events at the Marion/Kila site (not shown). Using the modeled baseline, a decrease of 112 ± 51 W per premises was estimated during the events. Using the controlled baseline, a decrease of 172 ± 61 W per premises was estimated. If the results from using the two baselines are averaged, the power was reduced by 142 ± 42 W at Marion/Kila premises having DRUs while the Peak Time events were active.

The project next analyzed the performance of the DRU premises in the 60-minute periods immediately following the termination of Peak Time events. Figure 10.16 shows the estimated per-premises impacts during these rebound hours at the Libby site, and Figure 10.17 shows the similar results for the Marion/Kila site. The results are shown by project month for any month that had Peak Time events. The aggregated results from the entire project are shown at the far right labeled “All.” The results appear similar at the two sites. The impacts are often positive numbers, meaning that additional energy was consumed these hours that followed the events.

Based on the modeled baseline at the Libby site, 398 ± 74 W additional average power was consumed the hour following Peak Time events at Libby premises that had DRUs. Using the controlled baseline, 417 ± 71 W more power was consumed per DRU premises. If the results from the two baselines are averaged, 408 ± 51 W more power was consumed during the rebound hour at DRU premises in Libby.

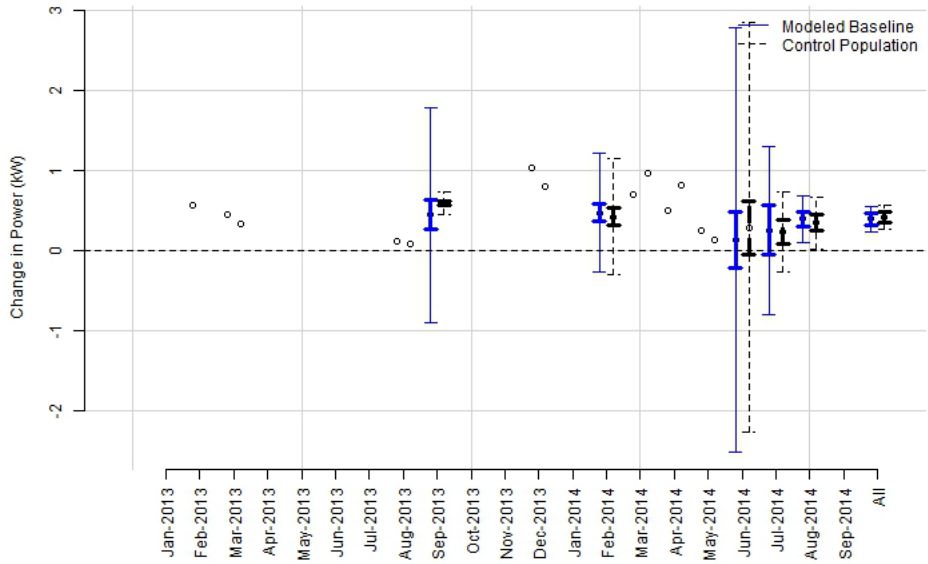

Figure 10.16. Averaged Monthly DRU Rebound Impacts per Premises at the Libby Site Based on the Modeled (blue) and Controlled (black) Baselines

At the Marion/Kila site, the modeled baseline estimate was 500 ± 110 W additional power consumed during the rebound hour, 387 ± 89 W using the controlled baseline. The averaged result from both baselines is that 441 ± 76 W additional power was consumed the rebound hour at the Marion/Kila site.

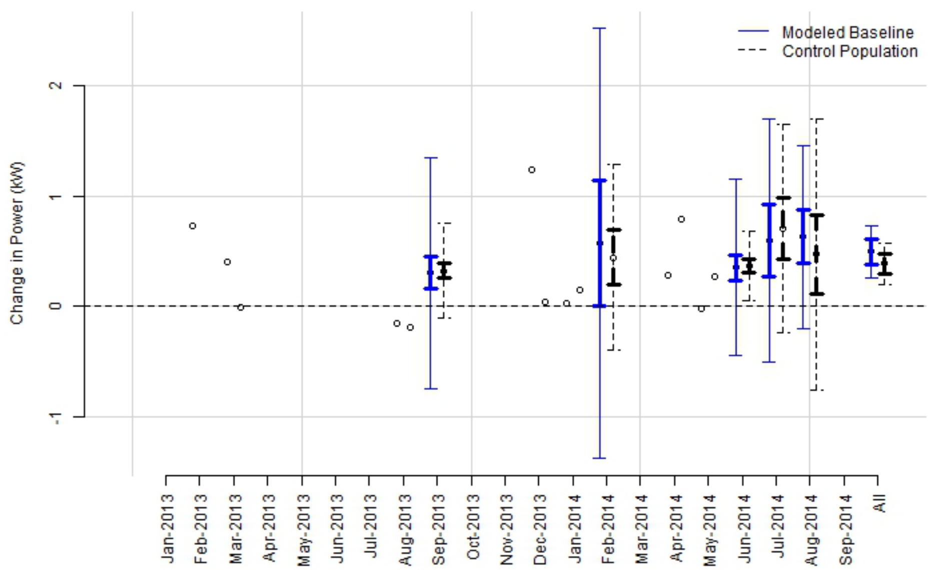

Figure 10.17. Averaged Monthly DRU Rebound Impacts per Premises at the Libby Site Based on the Modeled (blue) and Controlled (black) Baselines

Finally, the project estimated impacts of DRU events throughout the days on which Peak Time events had occurred. Figure 10.18 presents the average per-premises impact of DRU events on the day's average power consumption at the Libby site, and Figure 10.19 does the same for the Marion/Kila site.

The results are quite inconsistent from month to month. Many of the month's standard error ranges and 95% confidence ranges intersect zero. This uncertainty was evident, too, in the aggregated results for the entire project duration that is shown to the far right of these two figures. In Libby, DRU premises, on average, consumed 23 ± 12 W more throughout days that Peak Time events had occurred (i.e., 550 Wh more energy), according to the modeled baseline. The confidence of the result using the controlled baseline was poor. The combined estimate from both baselines, however, was the consumption of 15 ± 11 W more power throughout event days in Libby (i.e., 360 Wh more energy).

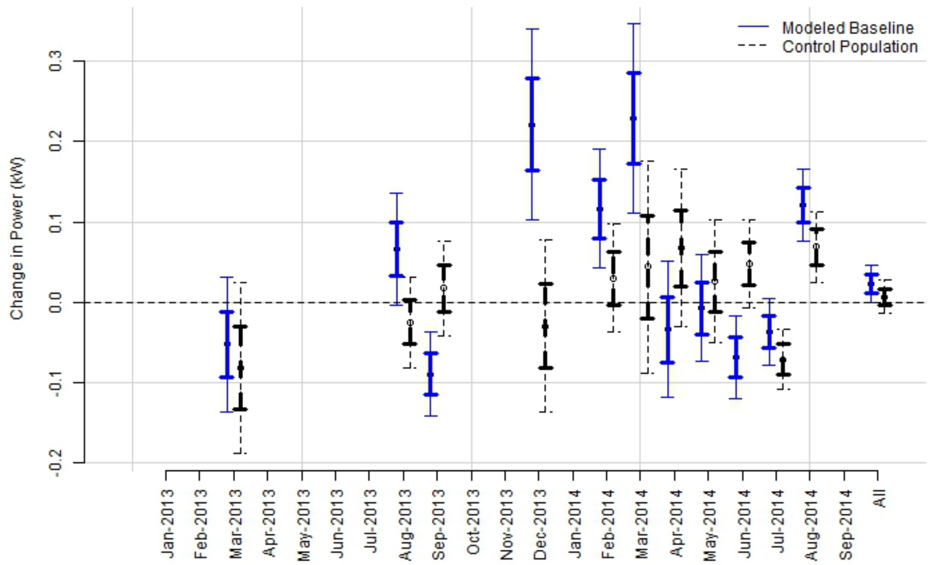

Figure 10.18. Averaged Monthly DRU Impacts per Premises at the Libby Site throughout Entire Days that Peak-Time Events had Occurred, Based on the Modeled (blue) and Controlled (black) Baselines.

Using the modeled baseline at the Marion/Kila site, DRU premises consumed 70 ± 15 W more power, on average, (i.e., 1.7 kWh more energy) throughout event days. The controlled baseline yielded a similar magnitude, but at marginal confidence levels. The combined estimate using both baselines was that Marion/Kila DRU premises consumed 46 ± 33 W more power, on average, (i.e., 1.1 kWh more energy) throughout days that Peak Time events had been called.

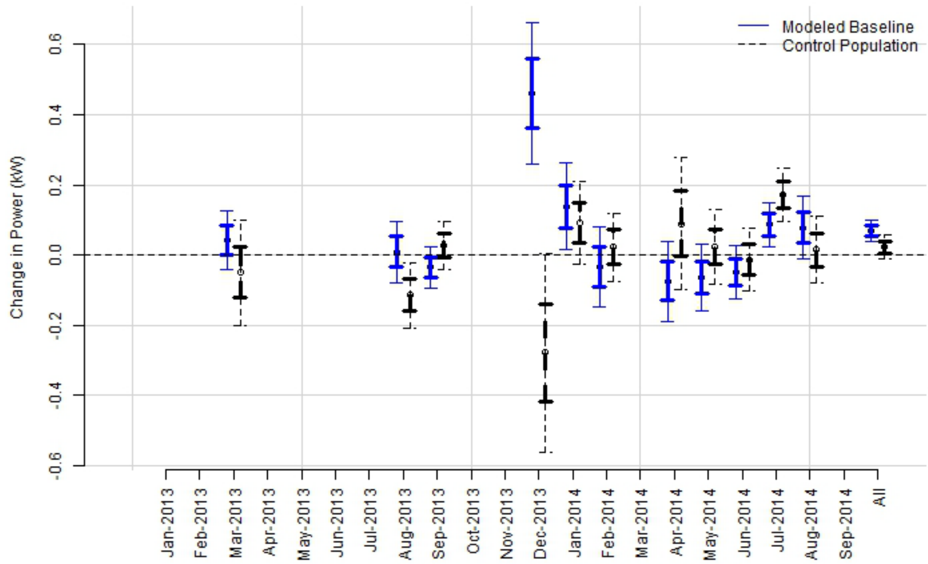

Figure 10.19. Averaged Monthly DRU Impacts per Premises at the Marion/Kila Site throughout Days that Peak-Time Events had Occurred, Based on the Modeled (blue) and Controlled (black) Baselines

Figure 10.20 presents a fairly prototypical event for the DRU premises. Event 2 from March 5, 2013 at the Libby site is the example event used in this figure. The horizontal axis includes 22 hours from this date, local Mountain Time. Each data marker shows the average per-premises power over 5 minutes for the test group at Libby that had received DRUs. Flathead premises metering was conducted at hourly intervals, so the measurements remained constant through each hour. Near the center of the figure, the blue data represents the power while the Peak Time event was reported to have occurred. The green data markers were for the rebound hour that followed the event. The average power prototypically decreased during the event and rebounded following the event.

Some analyzed DRU impacts may have become affected by event periods that did not perfectly align with the utility's hourly data collection intervals, as was often the case.

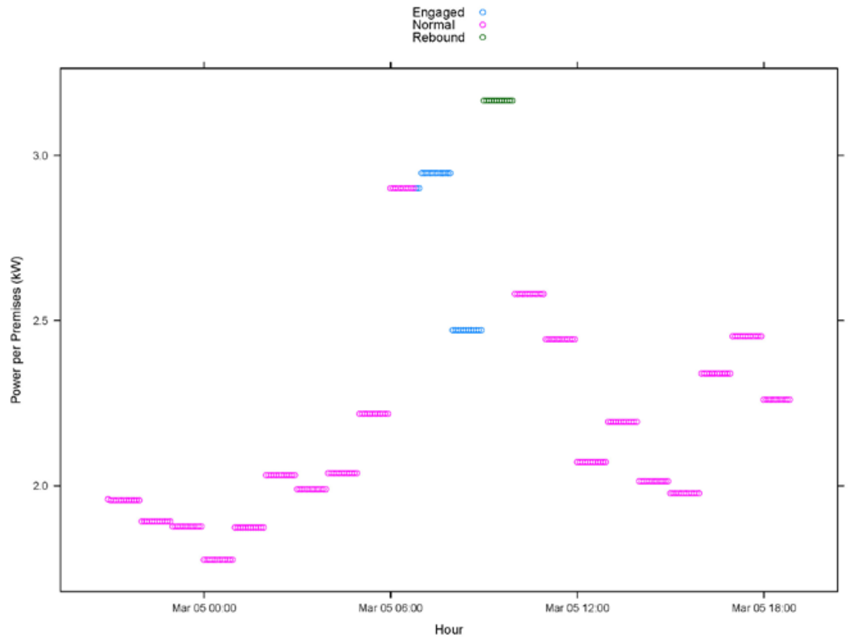

Figure 10.20. Average Premises Power for Libby DRU Owners Leading Up to and Following the Second Event. This result appears prototypical. This is Event 2 on March 5, 2013.

The project estimated the impacts of the system of DRUs at the Libby site on energy supply costs and on the demand charges that are incurred by the utility. The methods used here parallel the methods that were described in conjunction with Table 10.9 and Table 10.10 concerning the Libby in-home displays (Section 10.2.2). Those details will not be repeated here.

Table 10.15 summarizes the estimated impacts of the Libby DRUs on the utility's energy supply costs each calendar month. Presuming the utility were to operate the system as was demonstrated during the Pacific Northwest Smart Grid Demonstration, and further presuming that the utility were to also similarly use the system on the three calendar months during which the system was not actively demonstrated, the utility might avoid purchasing 775 ± 96 kWh of supply energy per year. The value of this energy is modest at $16 ± 2 per year.

Table 10.15. Estimated Energy Curtailed by Premises with DRUs each Calendar Month and the Supply Value of that Energy as the DRU Premises Responded to Peak Time Events

	HLH		LLH		Total	
	(kWh)	($)	(kWh)	($)	(kWh)	($)
Jan	-	-	-	-	-	-
Feb	−119 ± 67	−2.3 ± 1.3	-	-	−119 ± 67	−2.3 ± 1.3
Mar	−90 ± 19	−1.8 ± 0.4	-	-	−90 ± 19	−1.8 ± 0.4
Apr	−32 ± 2	−0.7 ± 0.1	-	-	−32 ± 2	−0.7 ± 0.1
May	−26 ± 9	−0.6 ± 0.2	-	-	−26 ± 9	−0.6 ± 0.2
Jun	−65 ± 18	−1.6 ± 0.4	-	-	−65 ± 18	−1.6 ± 0.4
Jul	−80 ± 15	−1.4 ± 0.3	-	-	−80 ± 15	−1.4 ± 0.3
Aug	−9 ± 37	−0.2 ± 0.6	-	-	−9 ± 37	−0.2 ± 0.6
Sep	−48 ± 4	−0.8 ± 0.1	−55 ± 6	−1.5 ± 0.2	−103 ± 7	−2.2 ± 0.2
…	-	-	-	-	-	-
Dec	−57 ± 4	−1.2 ± 0.1	-	-	−57 ± 4	−1.2 ± 0.1

The impact of the Libby system of DRUs on its yearly demand charges are estimated in Table 10.16 for each calendar month. The DRUs demonstrated a small effect on average HLH for nine of the 12 calendar months. The Peak Time events coincided with historical peak hours four of those months. In sum, if the system were to be operated throughout a full year as was demonstrated by the utility, the demand charges might be reduced by $1,163 ± 11 per year.

This estimate would be expected to scale nearly linearly if additional DRUs were to be installed. This analysis used only the demonstrated impacts on energy consumption during Peak Time events. Rebound effects and event-day effects were not explicitly included in the results.

Table 10.16. Estimated Impact of the System of Libby DRUs on the Demand Charges that are Incurred each Month by Flathead Electric Cooperative

	Δ Demand (kW)	Δ aHLH (kWh/h)	Δ Demand Charges ($)
Jan	-	-	-
Feb	-	−0.31 ± 0.17	3 ± 0
Mar	−36 ± 7	−0.21 ± 0.04	−341 ± 7
Apr	-	−0.08 ± 0.01	1 ± 0
May	-	−0.06 ± 0.02	1 ± 0
Jun	−16 ± 6	−0.16 ± 0.04	−150 ± 6
Jul	−26 ± 1	−0.20 ± 0.04	−243 ± 1
Aug	−15 ± 1	−0.02 ± 0.09	−145 ± 1
Sep	-	−0.12 ± 0.01	1 ± 0
…	-	-	-
Dec	-	−0.14 ± 0.01	1 ± 0

10.4 Demand-Response Appliances

Flathead Electric wished to investigate whether it is cost-effective for its members who already have AMI to additionally install a suite of communicating home appliances. The cooperative selected a suite of General Electric Profile Brillion™ appliances, a home energy gateway (Figure 10.21 and Figure 10.22), a 240 V water heater switch, and an energy display (GE 2014) and installed them at qualifying members' homes. Qualifying members were home owners who possessed electric water heaters, a home computer, and internet connectivity and who agreed to pay a deeply subsidized rate of $800 for the entire suite of devices. Participants committed to maintain the appliances in place or repay a pro rata value full appliance value if they removed the appliances from the program.

This system of home devices all communicated via the wireless ZigBee® specification (ZigBee Alliance 2014a). Flathead Electric Cooperative wished to send their Peak Time command to these ZigBee-enabled appliances (clothes washer, clothes dryer, dishwasher, and DRUs for water heaters and 240 V appliances) to conduct load curtailment.

An important lesson from this asset system was that the system components procured from the multiple vendors of the smart appliances, home gateways, and advanced premises metering were not interoperable. Flathead Electric led an intense effort to gradually integrate and test the system. While the GE equipment worked well together, the non-GE water heater switch and the connection to an Aclara meter was difficult. Some of the confusion appeared to result from the vendors' various stages of adopting and implementing the ZigBee Smart Energy Profile versions 1.0 or 2.0 (ZigBee Alliance 2014b). Eventually, an acceptable work-around solution was identified, but the communication routes were circuitous.

Figure 10.21. GE Nucleus™ Home Energy Gateway that was Used in the Flathead Electric Cooperative Peak-Time Project[1]

Figure 10.22. Example GE Home Energy Gateway Display[2]

Figure 10.23 is an example snapshot of the screen of Flathead Electric's Web portal that was available to its participating members. The portal is displaying the member's current rate for electricity, current power usage, an example of disaggregated energy cost information for a member's dishwasher, and the member's historical electricity consumption.

[1] Ibid.
[2] Ibid.

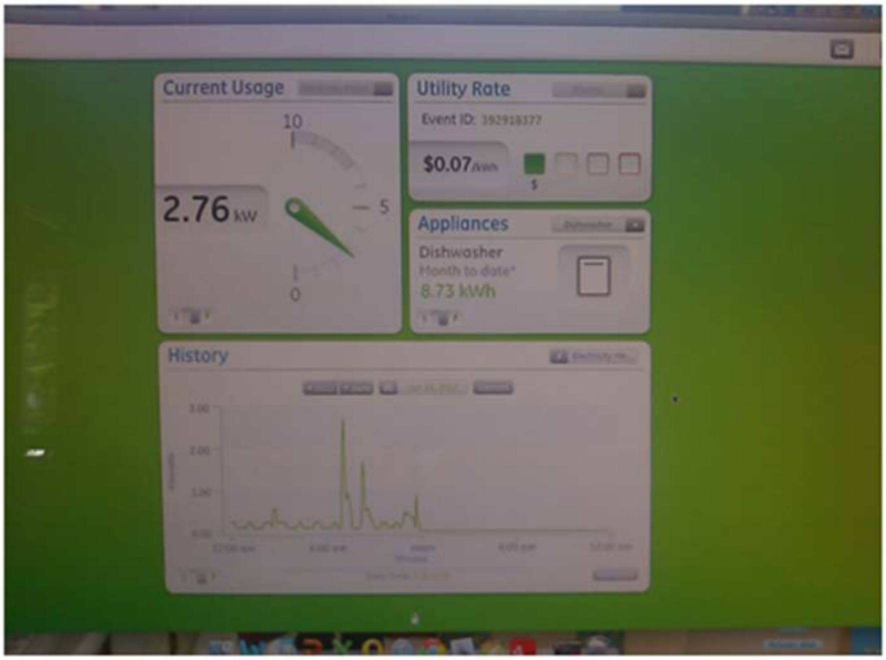

Figure 10.23. Example Web Portal Screen Available to Premises that Used the GE System of Communicating Appliances[1]

The benefit of the cost-additive technology of ZigBee wireless communication and smart appliances was evaluated by comparing costs and benefits of those members who install smart appliances against those who have only AMI. The annualized costs of the system and its components are summarized in Table 10.17 (Libby site) and Table 10.18 (Marion/Kila site). The ZigBee appliances, home energy gateways, and 240 V switches are the active hardware components of the system and account for much of the cost. Other cost components follow from software, utility staff labor, incentives, premises metering, and TWACS upgrades at substations. The total annualized cost of the Libby, Montana, demand-response appliance system was $207,100. The annualized cost at the Marion/Kila site was $174,500.

[1] Ibid.

Table 10.17. Incremental Annualized Costs of Demand-Response Appliances at the Libby, Montana, Site

	Shared Component Allocation (%)	Annualized Component Cost ($K)	Allocated Annual Component Cost ($K)	
ZigBee Appliances			158.4	
• Washers/Dryers	100	41.6		41.6
• Dishwashers	50	31.2		115.6
• Washers/Dryers (spares)	100	0.8		0.8
• Dishwashers (spares)	100	0.4		0.4
Integration Software	17	293.6	49.0	
Staff Support	13	293.1	36.6	
Home Energy Gateway (includes energy display)	50	66.7	33.3	
Incentives	100	20.0	20.0	
DRU 240 V Switch	50	11.0	5.5	
Back-End Metering	13	11.7	1.5	
Substation TWACS Components			0.9	
• Modulation Transfer Unit (Model Y87363)	25	1.4		0.3
• Inbound Pickup Unit (Model Y83760)	25	0.3		0.1
• Outbound Modulation Unit (Model 303)	25	1.3		0.3
• Control/Receiving Unit (Model 627)	25	0.9		0.2
Group-D Single-Phase Meters	50	1.5	0.7	
Meter Operations and Maintenance	25	2.4	0.6	
Demand-Response Software	33	1.1	0.4	
Total Annualized Asset Cost			**$207.1K**	

Table 10.18. Incremental Annualized Costs of Demand-Response Appliances at the Marion/Kila, Montana, Site

	Shared Component Allocation (%)	Annualized Component Cost ($K)	Allocated Annual Component Cost ($K)	
Integration Software	17	293.6	49.0	
ZigBee Appliances			36.4	
• Dishwashers	50	31.2		15.6
• Washer/Dryer Sets	100	20.8		20.8
Staff Support	13	293.1	36.6	
Home Energy Gateway (includes energy display)	50	66.7	33.3	
Incentives (rebates)	100	10.0	10.0	
DRU 240 V Switch	50	11.0	5.5	
Back-End Metering	13	11.7	1.5	
Group-D Single-Phase Meters	50	1.5	0.7	
Meter Operations and Maintenance	25	2.4	0.6	
Substation TWACS Components			0.5	
• Modulation Transfer Unit (Model Y87362)	25	0.7		0.2
• Inbound Pickup Unit (Model Y83765)	25	0.2		0.0
• Outbound Modulation Unit (Model 303)	25	0.7		0.2
• Control/Receiving Unit (Model 627)	25	0.4		0.1
Demand-Response Software	33	1.1	0.4	
Total Annualized Asset Cost			**$174.5K**	

10.4.1 Characterization of the Demand-Response Appliance System Responses

On an average monthly basis, the number of premises participating in the demand-responsive appliance test ranged from 67 to 101 at the Libby, Montana, site between August 2012 and the end of August 2014. There were between 12 and 17 participating premises at the Marion/Kila site between January 2012 and the end of August 2014.

There were 19 Peak Time events called for the appliances at both sites. See Table 10.19 and Table 10.20 for summaries of these events' starting times and durations. The ridiculously long first event at the Libby site was omitted from most of the analysis. Some additional problems and discrepancies were found between the utility's records and the project's records upon review by the utility, as are noted in the footnotes of these tables. During the analysis, the events in these two tables will be referred to as the set of Peak Time events.

Table 10.19. Peak-Time Event Times and Durations for the Libby, Montana, Demand-Response Appliances

	Year	Month	Day	Weekday	Hour	Minute	Length (h:m)
1[a]	2013	3	5	Tuesday	9	0	3873:45
2[b,c]	2013	8	15	Thursday	09	20	2:10
3[c]	2013	8	19	Monday	12	40	2:05
4[c]	2013	9	2	Monday	13	0	2:00
5	2013	9	3	Tuesday	12	0	2:00
6	2013	9	18	Wednesday	12	55	2:05
7	2013	12	9	Monday	1	0	2:00
8[c]	2014	2	10	Monday	17	30	2:00
9[c,d]	2014	2	11	Tuesday	9	0	2:00
10	2014	3	3	Monday	06	55	2:00
11[c]	2014	4	29	Tuesday	08	0	2:00
12[c]	2014	5	15	Thursday	09	45	2:00
13	2014	6	10	Tuesday	10	25	2:05
14[c]	2014	6	12	Thursday	10	0	2:00
15[c]	2014	7	1	Tuesday	11	40	2:05
16[c]	2014	7	14	Monday	13	20	2:10
17	2014	7	16	Wednesday	16	0	3:00
18[c]	2014	8	1	Friday	13	30	2:00
19[e]	2014	8	1	Friday	16	0	2:00

(a) The first event was "stuck" in its engaged state. This event period was excluded from analysis.
(b) The utility and project had discrepant records. Analysis was performed from database records that indicated this event began at 15:20.
(c) Coincides with an advised transactive event
(d) The utility, upon review, had no record of this event that was used in analysis.
(e) The utility and project had discrepant records. Analysis was performed from database records that indicated this event began at 17:00.

Table 10.20. Peak-Time Event Times and Durations for the Marion/Kila, Montana, Demand-Response Appliances

	Year	Month	Day	Weekday	Hour	Minute	Length (h:m)
1	2013	3	20	Wednesday	6	50	2:10
2[a]	2013	8	15	Thursday	9	20	2:10
3[a,b]	2013	9	2	Monday	16	15	2:45
4[c]	2013	9	18	Wednesday	06	55	2:05
5[a]	2013	12	9	Monday	18	0	2:00
6[a]	2014	1	30	Thursday	09	30	2:00
7	2014	2	6	Thursday	06	55	3:00
8[a]	2014	2	10	Monday	17	30	2:00
9[a]	2014	2	11	Tuesday	09	0	2:00
10[a]	2014	4	29	Tuesday	08	0	2:00
11[a]	2014	5	15	Thursday	09	45	2:00
12	2014	6	10	Tuesday	10	25	2:05
13[a]	2014	6	12	Thursday	10	0	2:00
14[a]	2014	7	1	Tuesday	11	40	2:05
15[a]	2014	7	14	Monday	13	20	2:10
16	2014	7	16	Wednesday	16	0	3:00
17[a]	2014	8	1	Friday	13	30	2:00
18	2014	8	1	Friday	17	0	2:00
19	2014	8	4	Monday	16	0	3:00

(a) Event coincides with an advised transactive event
(b) Project and utility records conflict. The project data caused analysis to look for this event starting at 22:15.
(c) Project and utility records conflict. The project data caused analysis to look for this event starting at 12:55.

The analysis of the performance of the suite of communicating appliances will be focused on the Peak Time events, when the appliances were reported to have been engaged by the utility. However, the next figures and paragraphs will refer to the transactive events. The project had requested that the assets should be engaged coincident with advice that was generated by the project’s transactive system. Eleven and 12 of the 19 Peak Time events at the two sites (58 - 63%) were found to have overlapped the events that had been advised by the transactive system.

Figure 10.24 summarizes the days of week on which the transactive system advised its events at the two Flathead Electric sites. The events were pretty uniformly distributed across the days. The most events were advised on Tuesdays, and the fewest on Fridays.

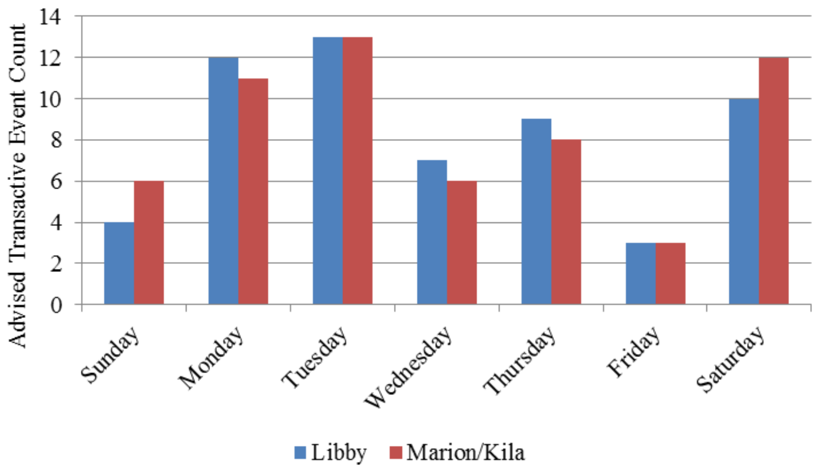

Figure 10.24. Days on which Transactive Events were Advised for the Group-D Premises in Libby and Marion/Kila

Figure 10.25 summarizes the local Mountain Time hours that the advised transactive events started at the two sites. An unexpectedly large number of events occurred at hour 0 just after midnight. These events likely occurred early in the project while the project was troubleshooting its transactive system's signals and before the utility had fully configured the transactive function that was used to advise events for this asset.

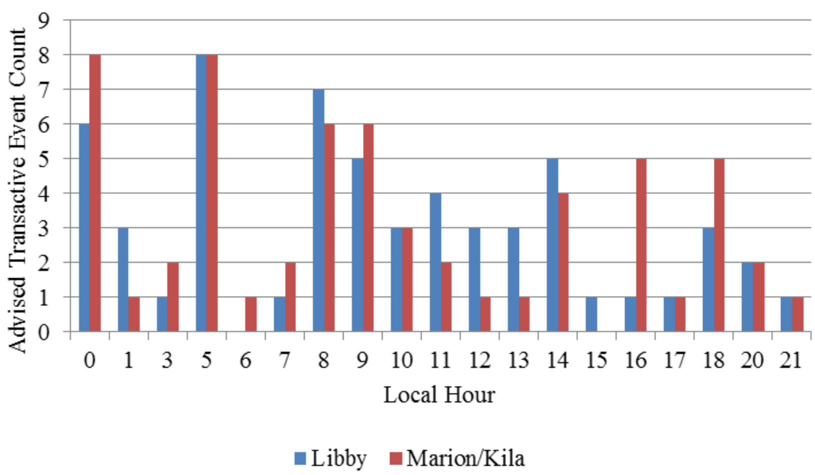

Figure 10.25. Hours on which Transactive Events were Advised for the Group-D Premises in Libby and Marion/Kila

10.4.2 Demand-Response Appliance System Performance

The cooperative installed and monitored the demand-response appliance asset system similarly at the urban Libby and the more rural Marion/Kila sites. One of the utility's objectives was to learn whether smart grid infrastructure is equally cost-effective in urban and rural settings.

Figure 10.26 estimates the average monthly per-premises impacts of the communication appliances during Peak Time events at the Libby site premises that had received these appliances. The modeled and controlled baselines were created the same as was done for the Group-B and Group-C analyses. The monthly ranges and aggregated results for all project months that are shown to the right of the diagram labeled "All" are perhaps more varied and uncertain than was observed for the system of DRU. The appliances include smaller loads that are less regularly used. Some are affected through the voluntary actions of their owners.

Using the modeled baseline at the Libby site, the suite of appliances was estimated to have reduced premises load during Peak Time events by 112 ± 34 W. Using the controlled baseline at this site, the reduction was estimated to be 168 ± 28 W. Combining the results from the two baselines, the appliance set reduced consumption by about 140 ± 40 W per premises during the Peak Time events in the Libby site.

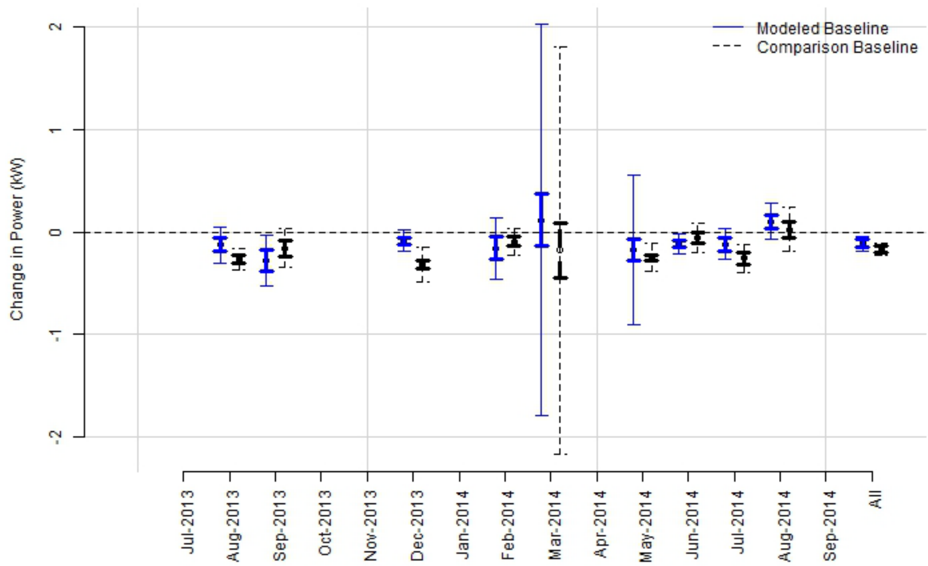

Figure 10.26. Change in Premises Power by Month during both On-Peak and Off-Peak Events at the Libby Site According to the Modeled (blue) and Controlled (black) Baselines

Greater reductions were estimated for the Marion/Kila site. The modeled baseline comparison showed power reduction of 198 ± 63 W, and the controlled baseline yielded reduction of per-premises load by 232 ± 59 W during the Peak Time events. The average from the two baselines was a reduction of 215 ± 43 W per premises during the Peak Time events.

Figure 10.27 summarizes the monthly results when the project looked at the impact on power consumption during the rebound hour at residences that possessed the communicating appliances. These results were inconclusive. The modeled baseline suggested that power consumption increased 75 ± 49 W during the hour following the Peak Time events, but no impact was found using the controlled baseline. If results from both baselines are averaged, the impact is a more modest 38 ± 51 W, reported with large uncertainty.

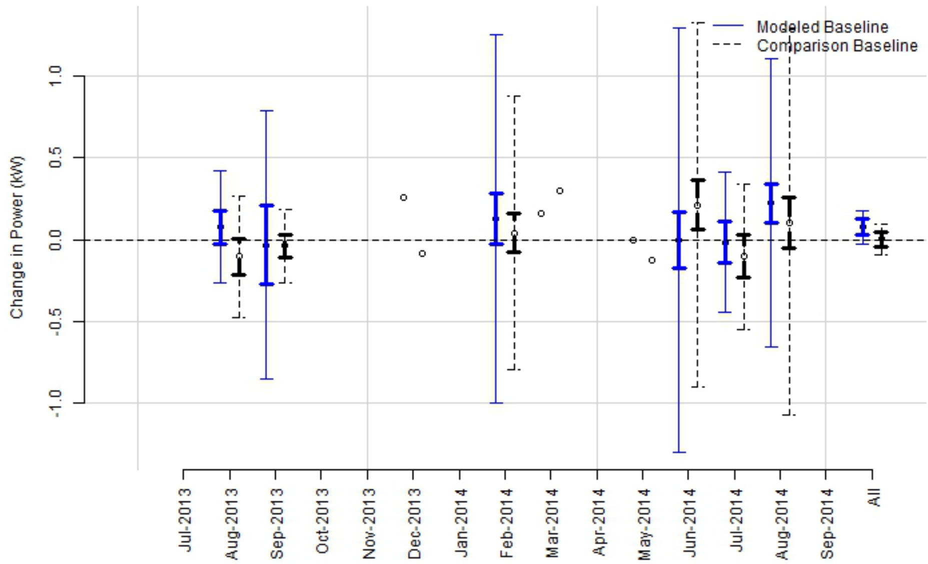

Figure 10.27. Change in Premises Power by Month during the Rebound Hour Following Events at the Libby Site According to the Modeled (blue) and Controlled (black) Baselines

Neither the modeled nor the controlled baselines at the Marion/Kila site suggested that any rebound impact had occurred.

Figure 10.28 summarizes the per-premises impacts that were observed at the Libby site throughout those days on which Peak Time events had occurred. Again, the results were highly variable from month to month. Using the modeled baseline, the impact was estimated as an average increase of 39 ± 11 W per premises on Peak Time event days at premises that possessed the appliances. If both baselines are used, the average is only about 12 ± 38 W, but this result is accompanied by great uncertainty.

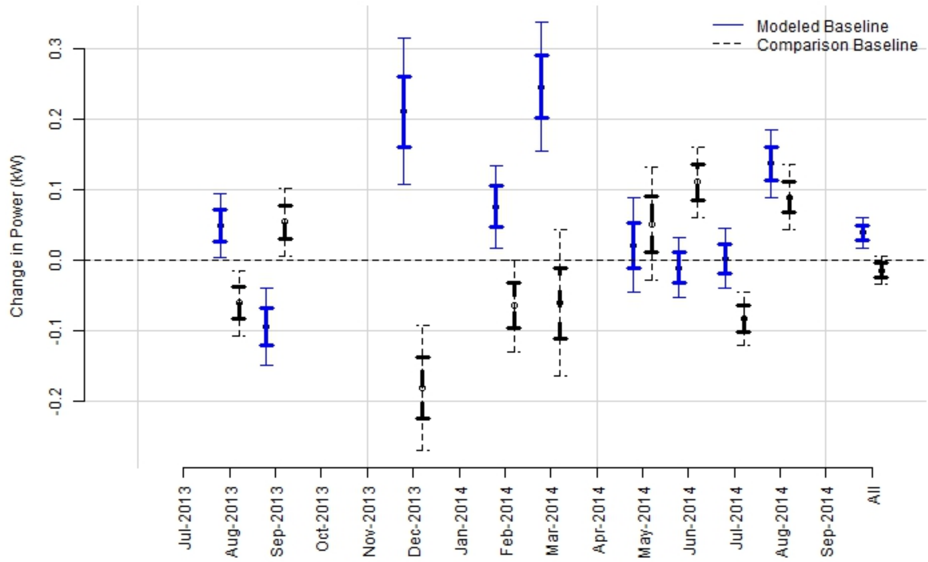

Figure 10.28. Change in Premises Power by Month during Following Event Days at the Libby Site According to the Modeled (red) and Comparison (blue) Baseline Approaches

Neither the modeled or controlled baselines resulted in event-day impacts at the Marion/Kila site with high enough certainty to report.

The project estimated the impact that the set of Libby communicating appliances had on energy supply costs and demand charges. The methods closely parallel those that were used and discussed in conjunction with Table 10.9 and Table 10.10 in Section 10.2.2 and will not be repeated here.

Table 10.21 summarizes the estimated impacts of the Libby system of communicating appliances on the costs of supply energy each calendar month. If the utility were to use the appliances all 12 calendar months as it demonstrated during eight project months, the project extrapolates that it would conserve about 800 ± 200 kWh per year with a supply value of $16 ± 4 per year. This estimate is based on the system's performance during the events periods only.

Table 10.21. Estimated Energy Curtailed by Premises with Communicating Appliances each Calendar Month and the Supply Value of that Energy as the Premises Responded to Peak Time Events

	HLH		LLH		Total	
	(kWh)	($)	(kWh)	($)	(kWh)	($)
Jan	-	-	-	-	-	-
Feb	−44 ± 21	−0.8 ± 0.4	-	-	−44 ± 21	−0.8 ± 0.4
Mar	−3 ± 33	−0.1 ± 0.7	-	-	−3 ± 33	−0.1 ± 0.7
Apr	-	-	-	-	-	-
May	−45 ± 8	−1.1 ± 0.2	-	-	−45 ± 8	−1.1 ± 0.2
Jun	−30 ± 10	−0.7 ± 0.2	-	-	−30 ± 10	−0.7 ± 0.2
Jul	−116 ± 27	−2.1 ± 0.5	-	-	−116 ± 27	−2.1 ± 0.5
Aug	−62 ± 130	−1.0 ± 2.0	−62 ± 65	−2.0 ± 2.0	−124 ± 145	−2.7 ± 2.7
Sep	−107 ± 42	−1.8 ± 0.7	−31 ± 8	−1.0 ± 0.0	−139 ± 43	−2.6 ± 0.7
Oct	-	-	-	-	-	-
Nov	-	-	-	-	-	-
Dec	−35 ± 3	−0.7 ± 0.1	-	-	−35 ± 3	−0.7 ± 0.1

Table 10.22 estimates the demonstrated monthly impacts of the Libby communicating appliances on the utility's demand charges each calendar month. The system had a small impact on the average HLH hour energy during the eight calendar months that the system was being demonstrated. The Peak Time events for these appliances coincided with historical peak hours four of these months. Presuming the system were operated all 12 months in the same way it was demonstrated, the utility might reduce its demand charges by only about $190 ± 10 per year.

Table 10.22. Estimated Impact of the System of Libby Communicating Appliances on the Demand Charges that are Incurred each Month by Flathead Electric Cooperative

	Δ Demand (kW)	Δ aHLH (kWh/h)	Δ Demand Charges ($)
Jan	-	-	-
Feb	-	−0.11 ± 0.05	1 ± 0
Mar	4 ± 4	−0.01 ± 0.08	38 ± 4
Apr	-	-	-
May	-	−0.11 ± 0.02	1 ± 0
Jun	−1 ± 2	−0.07 ± 0.02	−5 ± 2
Jul	−21 ± 3	−0.29 ± 0.07	−198 ± 3
Aug	3 ± 3	−0.14 ± 0.30	33 ± 3
Sep	-	−0.27 ± 0.11	3 ± 0
Oct	-	-	-
Nov	-	-	-
Dec	-	−0.09 ± 0.01	1 ± 0