Final

2005 Smart Thermostat Program Impact Evaluation

Prepared for

San Diego Gas and Electric Company
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E EXECUTIVE SUMMARY

E.1 INTRODUCTION

E.1.1 Background

On March 27, 2001, the California Public Utility Commission (CPUC) issued Decision 01-03-073 (D.01-03-073) mandating San Diego Gas and Electric (SDG&E) to implement a pilot program designed to test the viability of a new approach to residential load control and demand responsiveness through the use of Internet technology and thermostats to affect residential air conditioning use. To meet this mandate, SDG&E implemented the Smart Thermostat Program beginning in the spring of 2002.

In the summer of 2002, the program was invoked once. Previous reports provided a process and impact evaluations of the 2002 program. The impact evaluation provided both estimates of impacts on the single 2002 re-set day and projections of savings under alternate conditions.

In the summers of 2003 and 2004, the full program was not invoked but customers in the metering sample were re-set on the critical peak days of the Statewide Pricing Pilot (SPP). The impact evaluation report for those summers used these test re-sets to estimate impacts per unit for those days as well as projected savings under general conditions.

The present report provides the findings from an impact evaluation of the fourth summer of the program in 2005. In 2005, the full program was invoked 12 times allowing this evaluation to follow the original proposed methodology for the first time since 2002. This report estimates impacts per unit for the re-set days as well as projected savings under alternate conditions.

The analysis this year offers several methodological improvements over previous years:

- Unlike the previous two years, all of the 2005 re-set events included the full program population. Eleven of the 12 events were “standard” re-set events from an evaluation perspective. That is, part of the metered group, the comparison group for that day, was not re-set. For these 11 events, we were able to pursue the original proposed methodology to its full extent. Potential contributor percentages are based on actual program population percentages.
- In addition, we developed an alternative methodology that works without a comparison group. This methodology, the self-correction approach, was applied to all 12 events. This method provides an alternative estimation approach for situations when no comparison group is available or for future evaluations as the available metering sample shrinks from ongoing attrition.

- Finally, we developed and applied a new approach to modeling the probability of re-set override by program participants.

E.1.2 Program Description

General Structure

The Smart Thermostat Program was originally designed to include approximately 5,000 residential customers and represent an estimated four MW in peak demand reduction. For 2005 the program was extended with an adjusted peak demand reduction of two MW. In the summer of 2005, a maximum of 3,936 units were paged. Through the program, customers are provided the necessary technology installation and a small incentive for program participation. The equipment deployed allows SDG&E to remotely raise the cooling setpoints on participating customers' thermostats. Participating customers may override the re-set, but forfeit a portion of their incentive each time they do so.

Conditions for Calling a Re-set Event

The program plan calls for the deployment of the Smart Thermostat system when the California Independent System Operator (ISO) calls for a Stage 2 Emergency Notice (Stage 2 Alert). This alert is based on statewide conditions and may occur at times when the weather in San Diego is mild. In addition to a Stage 2 Alert, transmission or distribution emergencies can trigger a re-set event.

E.2 FINDINGS

As noted, the 2005 impact evaluation is based on 12 full program events. Impact results estimated using the original proposed methodology, now called the comparison group approach, are reported for 11 of the 12 events. Using the alternative self-correction approach, we report a second set of result for those 11 events. In addition, the self-correction approach is used to generate savings estimates for the "non-standard" event on July 12, 2005, and the similar event that took place on May 3, 2004. For these two events, the entire meter sample was re-set leaving no comparison group with which to do the comparison group approach.

E.2.1 Estimated Impacts for the Observed Re-set Events

Savings per unit enrolled in the program averaged over the re-set periods ranged from a low of 0.02 kW to a high of 0.49 kW across the 11 standard events in 2005. The event average was statistically significantly different from zero (at 90 percent confidence) for 9 of the 11 events. Averaged across all 11 "standard" events, the program impact was 0.30 kW. The 90 percent confidence interval, reflecting variation across days as well as units, was from 0.08 to 0.52 kW. Thus, for the 2005 impact evaluation, the overall impact estimate was statistically different from zero. Despite differences in re-set populations, these results are analogous to previous year results and are estimated with the same basic methodology, the comparison group approach.

The Smart Thermostat program has an *ex ante* savings estimate of 0.8 kW. In 2005, no events had estimated savings at this level. In fact, for the 2005 program average, the *ex ante* estimate of 0.8 kW is not even within the 90 percent confidence interval. The results of the 2005 events are somewhat below the results from the 2004 program year but quite similar to the result for 2003. These estimates are summarized in Table E-1.

Table E-1
Estimated Impacts, Comparison Group Approach

	Impact (kW)	Standard Error	90% Confidence Lower Bound	90% Confidence Upper Bound
Average of All Events				
per unit	0.35	0.14	0.12	0.57
5000 units	1,728	684	602	2,853
Average of 2005 Events				
per unit	0.30	0.13	0.08	0.52
5000 units	1,495	670	394	2,597
Average of 2004 Events				
per unit	0.43	0.16	0.17	0.69
5000 units	2148	791	847	3,449
Average of 2003 Events				
per unit	0.30	0.14	0.08	0.53
5000 units	1,520	684	396	2,645

E.2.2 What Fraction of Units Contribute to Savings

The fraction of participating units contributing to savings was found to be low in this analysis, as in previous years.

Non-Responding Units

- The non-response rate (the fraction of units in the program that do not receive re-set signals) across the 12 events for 2005 averaged 8 percent. Fully 6 percent of program participants were non-responders for every re-set event for which they were sent re-set signals.
- Non-response appears to be worse for the more recent additions to the program. Of the 263 meters re-set for only the four October dates, 19 percent never received the signal.
- The non-response rate among the meter sample averaged 11 percent. Essentially all non-responders in the meter sample were non-responders for every re-set. In the absence of full program information, this is the non-response estimate that would have been used. Since the full program information is available for 2005, we recommend the average of this complete information (8 percent, above) as the best estimate for projections or future cases where the actual response rate is not known.

Over-Ride Rates

- The override rate across the 12 2005 events averaged 22 percent. It ranged from a low of 9 percent to a high of 39 percent. Forty percent of the program population never overrode the re-set during an event. A negligible percent overrode every re-set event.

Zero Users

- The percentage of AC units never used during summer weekdays was 17 percent for the 2005 cooling season. This percent is estimated from the meter sample. It is the same percent as in the summer of 2004.
- AC non-use cannot be tracked in the program data. The non-use estimate cannot be checked. This estimate may be inflated if AC meters at the residences are found to be giving false zeros. At this time each false zero meter increases the percent AC non-use by approximately 1 percent. This issue is under review by SDG&E personnel.

Overall Percent Contributing to Savings

The combined effect of non-response, over-ride, and non-use was an average of 44 percent of participating units that did not contribute to savings in 2005. This level falls in between the non-contributor percentages from 2003 and 2004, 42 percent and 48 percent, respectively.

E.2.3 Alternative Methodology Compared

The results reported above were all produced with the original methodology with some minor variations in 2005. We also report 2005 results produced with the alternative methodology, the self-correction approach. This approach has the advantage of not requiring a comparison group. The self-corrected approach savings per AC unit average 0.25 kW across the 11 “standard” event days. Once again, 9 results from the 11 standard re-set events are statistically different from zero. The 0.05kW difference between the two approaches is not statistically significant. These estimates are summarized in Table E-2

Table E-2
Estimated Impacts, Self-Correction Approach

	Impact (kW)	Standard Error	90% Confidence Lower Bound	90% Confidence Upper Bound
Average of 2005 Events: Comparison Approach				
per unit	0.30	0.13	0.09	0.51
5000 units	1,495	633	452.95	2537.12
Average of 2005 Events: Self Correction Approach				
per unit	0.25	0.10	0.08	0.42
5000 units	1,265	522	405.86	2123.60

E.2.4 All-Sample Re-set Day Results

The 2004 and 2005 programs each had one re-set event that was not “standard” from an evaluation perspective. In both cases there was no comparison group. The self-correction approach makes impact estimates possible for these two event days. The May 3, 2004, event generated statistically significant results estimating 0.22 kW of savings. The July 12, 2005, event produced negative results. In both cases the estimated results are substantially less than what has been projected given the event characteristics. The May 3, 2004, projection was 0.64 kW and the July 12, 2005, projection was 0.13 kW. These results are summarized in Table E-3

Table E-3
Estimated Impacts for Full Population Re-set Events, Self-Correction Approach

Re-set Event Date	Start time	End time	Average Temperature	Degrees Setback	Group AC Count	Mean Impact for Contributing AC Users	Percent Contributing AC Users	Mean Impact per AC Unit	Standard Error
5/3/2004	4:00 PM	7:00 PM	82	4	52	0.45	50%	0.22	0.10
7/22/2005	2:00 PM	7:00 PM	80	4	13	0.92	42%	0.38	0.12

E.2.5 Projected Impacts for Future Events

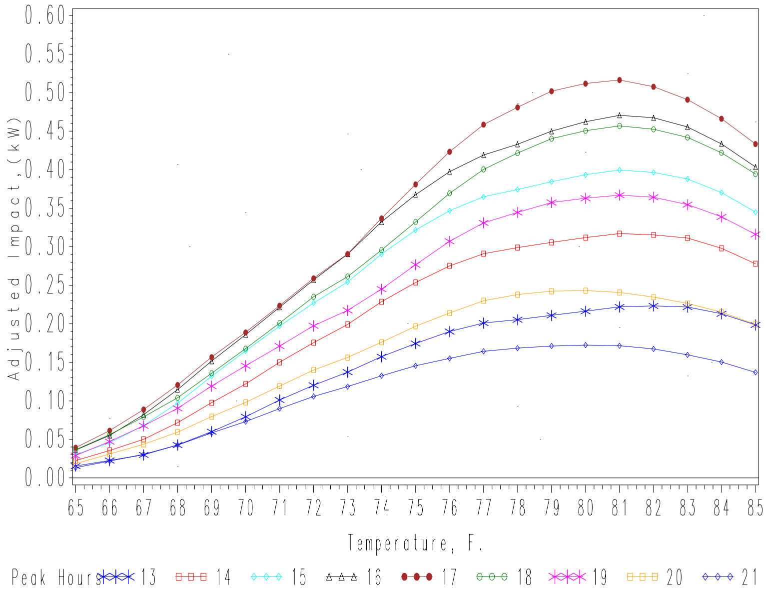
Impacts projected for a future re-set of 4°F and five hours in length are indicated in Table E-2 for the hour ending 5 PM. For 2005, this is the hour with the highest peak impacts for all ambient temperatures. Maximum savings occur at a daily average temperature of 80°F and 81°F. A 4°F re-set is estimated to yield 0.49 kW savings per thermostat at this temperature and hour. The savings at hour ending 1 PM is only 0.13 kW.

Table E-4
Projected Impacts per Participating AC Unit by Outside Temperature, 4°F Re-set of 4 Hours, Hour Ending 5 PM

Average Daily Temperature	Impact per Thermostat (kW)
70	0.19
71	0.22
72	0.25
73	0.28
74	0.33
75	0.37
76	0.41
77	0.44
78	0.46
79	0.48
80	0.49
81	0.49
82	0.48
83	0.46
84	0.43
85	0.40

Figure E-2 shows the projected savings per participating unit as a function of daily average temperature for an event duration of four hours for hours ending 1 PM to 9 PM. For the hours between 1 PM and 7 PM, savings increase steadily into the low eighties at which point the override rate takes over and the savings decrease.

Figure E-1
Projected Impacts per Participating AC Unit by Outside Temperature,
4°F Re-set of 4 Hours, Hour Ending 1 PM through 9 PM



E.3 IMPLICATIONS OF THE FINDINGS

The findings from this year's analysis provide another sobering piece of evidence that the future performance of the Smart Thermostat program, as a mechanism to respond to statewide emergencies, is not fully reliable. The savings estimates for 2005 fell back to the levels experienced in 2003. This was despite temperatures that were closer to 2004 levels than 2003. The higher savings estimates of 2004 now appear to be the exception.

Previously, we have reported a number of factors that might explain the shortcomings of the program. One factor is the limited used of air conditioning in the territory; just under one-fifth of participating units were never used over the summer. Another factor is that statewide emergency conditions do not necessarily coincide with hot weather in the San Diego area. As long as the emergency condition that triggers a re-set event is not tied to hot weather in San Diego, a high number of non-users is likely to be found during future re-sets. Finally, when the weather is hot, higher rates of override are projected to occur. Thus, while the program is capable of savings of the desired 4 MW magnitude, it is unlikely to realize these savings in full on the day of a statewide emergency.

The timing of the 2005 events was more closely aligned with hot weather than in the previous two years, and still the magnitude of the savings fell from 2004. Better event timing does not appear to translate into higher impacts. This appears to indicate that the program's limitations are more a factor of San Diego's weather patterns, which is characterized by milder weather overall and short-lived hot spells and the associated cooling behavior of participants.

1 INTRODUCTION

1.1 BACKGROUND

On March 27, 2001, the California Public Utility Commission (CPUC) issued Decision 01-03-073 (D.01-03-073) mandating San Diego Gas and Electric (SDG&E) to implement a pilot program designed to test the viability of a new approach to residential load control and demand responsiveness through the use of Internet technology and thermostats to affect residential air conditioning use. The Energy Division recommended a budget of $3.9 million per program year. To meet this mandate, SDG&E implemented the Smart Thermostat Program beginning in the spring of 2002. The Smart Thermostat program was extended for the 2005 cooling season with a funding level of $841,000. This report provides the findings from an impact evaluation of the fourth summer of this program, the summer of 2005.

1.2 PROGRAM DESCRIPTION

1.2.1 General Structure

The Smart Thermostat Program was originally designed to include approximately 5,000 residential customers and represent an estimated four MW in peak demand reduction. For 2005 the program was extended with an adjusted peak demand reduction of two MW. In the summer of 2005, a maximum of 3,936 units were paged. Through the program, customers are provided the necessary technology installation and a small incentive for program participation. The equipment deployed allows SDG&E to control the thermostat for emergency demand reduction, yet allows the customer the ability to override the company signal remotely or directly at the thermostat.

The program's paging technology allows SDG&E to remotely raise the cooling setpoints on participating customers' thermostats. We refer to this action by SDG&E as a "re-set event." The effect of the higher setpoint is a reduction in the average demand of the air conditioners. This reduction is the desired demand impact.

1.2.2 Conditions for Calling a Re-set Event

The program plan calls for the deployment of the Smart Thermostat system when the California Independent System Operator (ISO) calls for a Stage 2 Emergency Notice (Stage 2 Alert). A Stage 2 Alert is issued when an Operating Reserve of less than 5 percent exists or is forecast to occur within the next two hours for the state. In addition to a Stage 2 Alert, transmission or distribution emergencies can trigger a re-set event.

When a Smart Thermostat re-set event is initiated, SDG&E will increase the setting of the thermostat in participants' homes for a period of two to six hours. The re-set may be extended or terminated as necessary. SDG&E has set a maximum of 20 re-sets per calendar year.

1.2.3 Incentives

The customer receives a state-of-the-art digital thermostat installed at no cost to the participant. In addition, the participant will receive up to $75 in incentives for 2005. As noted, the participant may override the increased setpoint of the re-set. However, each time the customer overrides the re-set, the incentive will be reduced by $5. The incentive, less any reduction due to override, is to be paid each year. This incentive structure is a change from previous years when the base incentive was $100 and the penalty for override was just $2.

1.2.4 Targeting

The targeting strategy for the program was prescribed by the CPUC in D.01-03-073, the decision mandating the program. The decision directed SDG&E to target the following three customer groups:

1. Residential customers whose average monthly electricity consumption is greater than average for their customer class, with the exact specified consumption level to be determined by SDG&E.
2. Residential customers in geographical areas in SDG&E's service territory known to have high electricity consumption due to climate.
3. Residential customers in known limited to moderate income areas.

Medical baseline customers are not permitted to participate due to the potential air conditioner needs of these customers.

SDG&E met criteria 1 and 2 by selecting customers from California Energy Commission (CEC) Climate Zone 10 who had average monthly summer consumption of 700 kWh or greater. Data from MIRACLE XIII, SDG&E's residential appliance saturation survey, were used to estimate the average consumption for those residing in SDG&E's Transitional Climate Zone with central air conditioning. The average monthly summer kWh consumption for SDG&E's Transitional Climate Zone residents with central air conditioners was 700 kWh. The Transitional Climate Zone was used as a proxy for CEC Climate Zone 10, since the MIRACLE survey data were collected for the SDG&E climate zones (Maritime, Coastal, and Transitional zones). Initially, residents in CEC Climate Zone 10 with average monthly summer consumption of 700 kWh or greater were selected. In an effort to increase participation, an additional mailing was conducted during October 2002, and a follow-up mailing was to take place approximately one month later. Targeted customers for this mailing included those in CEC Climate Zone 10 with average monthly summer consumption of at least 600 kWh.

Criteria 3 was met by selecting customers under SDG&E's low-income rate class, the DR-LI rate, in CEC Climate Zone 10, whose average monthly summer consumption was 700 kWh or greater.

1.3 IMPACT EVALUATION

SDG&E was required to evaluate this program effort, including both a process evaluation and load impact evaluation components. The process evaluation was completed for program year 2002. The primary objectives of the process evaluation were to assess how efficiently and effectively SDG&E runs the program and to make suggestions for improvements. As part of that evaluation effort, survey data were collected from a sample of participants. These survey results shed some light on impact findings. Impact evaluations for the single re-set event in 2002 and the 12 re-set events in both 2003 and 2004 were completed.

The load impact evaluation presented in this report provides estimates of the aggregate demand reduction from summer 2005 re-sets. As with the two previous evaluations, savings estimates were derived from 12 re-sets of the metering sample. The 2005 test re-sets were all four degrees in magnitude and ranged from two to five hours in duration. All but one event started at 2 PM. The later event started at 3:10 PM.

For the first time since 2002, the 12 re-set events were not "test" re-sets but encompassed the full population of the Smart Thermostat program. The data from these test re-sets allowed us to evaluate the program using the original proposed methods. As in previous years, estimates are also provided for projected savings of future events as a function of the ambient temperature for the day and the length of the re-set event.

1.4 ORGANIZATION OF THE REPORT

Section 2 describes the impact analysis methods, including the data sources and the analytic approach. The findings from the analysis are presented in Section 3. Conclusions are summarized in Section 4. Plots of observed and estimated loads and impacts for each re-set day are given in Appendix A for the air conditioner load data analysis, and in Appendix B for the whole-house load data analysis. Tables of projected savings by temperature, time of day, and re-set amount are given in Appendices C and D.

2 METHODS

The original methodology relies on a split sample with only half of the metered sites being re-set for any given event. The comparison group provides information on possible systematic biases in the load estimates. However, the circumstances of re-set events in each year have necessitated some adjustments to that approach. In addition, we have developed some refinements to the basic methods in each year.

Previous evaluations were marked by limited re-set events (2002) or multiple re-sets of a limited scope (2003, 2004). As a result, for the 2002 evaluation, only one re-set event was evaluated. In 2003 and 2004, up to 12 events were evaluated, but the full program was not re-set. The full potential of the proposed methodology was still untested.

In this, the fourth year of the Smart Thermostat Program evaluation, we return full circle to the original methodology proposed in 2002. During the summer of 2005, there were 12 full program re-sets, and there is full program population data on signal receipt and re-set override. Thus, for the first time, we can fully explore the potential of the original methodology.

In both 2004 and 2005, the program started the season off with an event where all metered sites were re-set leaving no comparison group. For 2005 we have developed an alternative methodology that does not require a comparison group. This approach makes it possible to evaluate the two events lacking comparison groups. In addition, it provides an alternative estimate for the remaining events by ignoring the comparison group that does exist. Comparing this self-correction methodology to the full-blown original methodology provides further insight into the evaluation process of these kinds of demand response programs.

For the 2005 evaluation, we also made refinements to the impact projection methodology. The nature of the Smart Thermostat program with its re-set override option puts a premium on properly estimating override percent under different conditions. This year, we take a survival analysis approach to estimate the percent of overriders.

Section 2.1 discusses the data and how it was collected. Section 2.2 contains a discussion of the original methodology, which is put to full use in this report. Also in 2.2 is a discussion of the alternative self-correction methodology. Section 2.3 discusses the impact projection methods, including the new survival analysis approach for estimating override percent.

2.1 DATA SOURCES

There were three types of data collected for this study:

1. Interval metering data,

2. Weather data, and
3. Re-set operations data.

Energy consumption data continues to be collected from interval meters installed at a sample of Smart Thermostat Program participants by SDG&E in 2002.

For the 2005 analysis, for the third year running, SDG&E has provided weather data from 10 local weather stations. This is a substantial improvement over the single weather station used for the 2002 analysis since modeling the dependency of air conditioning energy consumption on ambient temperature is a central part of the method employed in this impact analysis.

Event data comes from Silicon Energy, the implementation contractor responsible for the Web-based control system. The control system collects data on participants' thermostat performance during re-set events. Those data were available directly from the Silicon Energy EEM Suite Web site.

2.1.1 Metered Data

Energy Consumption Data

Two streams of energy consumption data are collected at each study participant's premise:

1. Whole-premise (WH) and
2. Air conditioning (AC).

These streams are monitored on separate meters installed by SDG&E. Both meters record energy consumption accumulated over 15-minute intervals. SDG&E provided the energy consumption data for the 2005 cooling season.

Further information on each site is available from the original 2002 meter installation survey data set. The survey data include information on nominal cooling capacity, estimated age of AC condenser, and AC type. The survey data also contain information necessary to collate the energy consumption data with the re-set event data.

As the name suggests, whole-premise data monitors all loads at the premise including the AC condenser. Whole-premise data are valuable to the impact assessment of an AC demand reduction program because other loads may be affected by changes in the AC load. For example, greater use of ceiling, floor, or desk fans may accompany decreased cooling by the AC. Refrigerators will run more as less cooling allows the interior temperature to climb, and water heaters may run less. There may be an increased tendency among occupants to lessen internal heat gains, such as cooking, clothes drying, and lighting. These uncertain variables can have marked effects on the impact of an AC demand reduction program. Theoretically, the total impact at a premise is best viewed from the perspective of whole-house consumption.

Unfortunately, the variation of non-AC electrical loads at a premise can make it difficult to discern the impacts of AC demand reduction from whole-premise data alone. The fundamental dependency of AC use on ambient temperature may become more difficult to capture. For this reason, AC-only data are also collected.

The AC energy consumption data collected are taken from the circuit of the AC condenser, that part of the AC system located outdoors that dumps heat from the premise to the ambient environment. The condenser's load includes those of the refrigerant compressor motor, the cooling fan motor, condenser controls, and case or emollient heaters if present. The heaters are found generally in older condensers and serve to vaporize any liquid refrigerant that might enter the compressor. It seems that many run near continuously, perhaps even throughout the heating season.

The condenser is the largest but not the only load in an AC system. The system typically includes the same interior air distribution fan used by a forced-air furnace. The fan demand is approximately 150 Watts per nominal ton of AC capacity, or on the order of an additional 10 percent of condenser demand. Common air conditioner load control programs of the past involve controlling only the condensers with exterior control switches. This type of "cycling" control does not turn off the interior air distribution fan. By contrast, during re-set, the Smart Thermostat is understood to turn off the interior air distribution fan just as it would under ordinary AC operation when the cooling setpoint is raised.

The interior air distribution fan is not on the same circuit as the condenser. In fact, it may be on a circuit with other non-AC loads. To collect data from both the condenser and the interior distribution fan alone thus might involve the time-consuming task of wiring sensors. For that reason, energy consumption data were collected from the condenser circuit alone and does not capture the impact of turning the interior fan off when the cooling setpoint is raised. This, then, is another reason to consider whole-premise data in a demand impact analysis.

Sample Design

The energy consumption data are collected from the random sample of 100 premises of program participants that were selected early in the first year of the program, 2002. At that time, premises were limited to those with no more than two thermostats. The sample was divided randomly into two groups of approximately equal numbers of premises. The grouping was intended to allow one-half of the sample to serve as a comparison group for the other half for each re-set event. Thus, for each re-set, one group would be re-set while the other group continued to operate their AC as usual. With multiple re-set events, this would permit each group to be re-set in about half the events and to act as the comparison group for the other group in the other half of the event.

Table 2-1 describes the original sample in terms of numbers of premises, thermostats, and AC metered for each group. The table divides premises into categories by count of thermostats on the premise and numbers of AC metered. Each group had a two-thermostat premise where only one AC was metered. Otherwise, all ACs were metered at all premises.

Table 2-1
Original 2002 Distribution of Premises, Thermostats, and Metered AC by Group in Sample

Premise Category	Sample Group A			Sample Group B		
	Premise Count	Thermostat Count	Count of Metered AC	Premise Count	Thermostat Count	Count of Metered AC
One AC, one metered	45	45	45	42	42	42
Two AC, one metered	1	2	1	1	2	1
Two AC, both metered	5	10	10	6	12	12
Total	51	57	56	49	56	55

The re-set and comparison groups differed by no greater than a count of one between premise, thermostat, and metered AC categories. The two groups likewise were very similar in terms of nominal cooling capacity. Sample Group A had a combined capacity of 214.5 tons, while sample Group B had a combined capacity of 202.5 tons. Average sizes were 3.8 and 3.7 tons per unit, respectively.

Subsequent program years have seen some attrition in the metering sample. At least one of the two interval meters has been removed from six sites. The greater loss has been in actual program participation, that is, in taking part in thermostat re-sets. Since the 2004 analysis, ex-participants with valid metering data have remained in the analysis despite not actively participating in the program.

2.1.2 Weather Data

SDG&E provided observations of hour-ending average drybulb temperature and relative humidity for the period from April 2005 through October 2005 from 10 weather stations in the SDG&E service territory. SDG&E provided a list of program premises indicating the most appropriate weather station for this analysis. Seven of the 10 weather stations are used to describe the weather conditions for the 2005 sample of 94 premises. Table 2-2 shows the distribution of premises across the seven weather stations as well as the monthly mean temperature. For this analysis, daily average temperature is defined as the average of the daily maximum and minimum temperatures. Monthly mean temperature is the mean of the daily average temperatures across the month.

Table 2-2
Sample Group Distribution Across Weather Stations
with Summer Monthly Mean Temperature

Weather Station ID	Sample Group		Monthly Mean Temperature				
	A	B	June	July	August	September	October
S01		1	66	70	71	68	66
S02	19	22	65	71	71	67	64
S04	2		65	69	69	65	62
S05	14	16	69	75	76	72	68
S06		1	65	69	70	71	67
S08	8	6	65	74	74	67	62
S09	3	2	64	69	69	67	64

Having weather data from multiple weather stations, available since 2003, is a substantial improvement over the single weather station used for the 2002 impact analysis. The combination of the ocean and mountainous terrain has the potential to cause highly variable weather conditions across the SDG&E service territory. These weather data better represent the varied ambient conditions faced by the sample of program participants.

2.1.3 Event and Customer History Reports from Silicon Energy

The Silicon Energy EEM Suite Web site (http://sdgerem.siliconenergy.com/siliconenergy/rem/asp/event_summary_setup.asp) allows ready access to, and downloading of, data on customer participation in the summer's re-set events. These data include an observation for each thermostat that has been included in each re-set. Each observation identifies the sample group to which the thermostat belongs as well as customer name and account number information. Additional fields describe the start time and planned duration of the re-set event, the amount in degrees Fahrenheit of the thermostatic cooling setback, and time stamps of thermostat acknowledgement of re-set and of override as appropriate. It is these last two time stamps that (1) identify "non-responder" thermostats that do not appear to receive the re-set signal and (2) override thermostats where the thermostat is manually lowered after being raised by the re-set signal.

2.2 IMPACT METHODS

This section describes the methods by which the collected data were examined to estimate demand impacts. The original methodology proposed for the impact analysis has three main parts.

1. Calculate the fraction of units potentially contributing to savings for each event.
2. Calculate the impacts for each re-set period for potential contributors only.
3. Adjust the impact for potential contributors with the actual fraction of potential contributors to derive a per unit impact estimate for all program participants.

The new self-corrected methodology will only differ from the original methodology in part two. We will use a different approach to calculate impacts for potential contributors that does not rely on a comparison group.

Finally, we extend the impact estimation methodology to provide estimates of potential impact across a range of program and weather scenarios. An essential part of the impact projection process is estimating override as a function of program and weather scenarios. For the 2005 analysis, we utilize survival analysis techniques to model override percent.

2.2.1 Potential Contributors

The methodology pursued for this analysis focuses on potential contributors. Thus, we must identify non-contributors in both the sample groups and the program population. There are three reasons a unit might not contribute to demand savings during a re-set period.

1. The unit failed to receive the re-set signal.
2. The unit received the re-set signal, but the customer overrides the re-set.
3. The unit was not in use at the time the re-set signal was sent, therefore had no reduction to provide.

Signal Failure Fraction

Signal receipt itself is not directly observed. What is known for all participating units is whether they returned a signal to the system head end acknowledging receipt of the re-set signal. We used the percent of units that did not send an acknowledgement as an upper bound on the percent that did not receive a signal. If the signal transmission in each direction is such that virtually any unit that successfully received a re-set signal would successfully return an acknowledgement, this percent of non-responders is very close to the percent that did not receive a signal and is not an overstatement.

On the other hand, if signal failure randomly affects a fraction of units essentially symmetrically and independently in each direction, the fraction non-responding overstates the fraction not receiving a signal. In this case, we can assume that half the non-responders did not receive a signal and half received a signal, but the response signal failed. Thus, we would treat one-half the observed fraction of non-responders as a lower bound on the percent not receiving the re-set signal.

Finally, it is possible that a participating unit received and acknowledged the re-set signal, but did not properly re-set. In this case, the number of units not being re-set would be increased. Recognizing these potential sources of over- and under-statement, we treated the percent not acknowledging the re-set signal as the percent that were not re-set.

The summer 2005 events all included the full program population. This means, for the 2005 analysis, the percent of non-responders across the whole population is known, with zero variance, from the participation data. This is an advantage over the 2003 and 2004 analyses when we had to estimate the population non-response rate.

Override Fraction

Silicon Energy records a timestamp when a thermostat is changed during a re-set event. This provides a direct indication of which units are over-riding the re-set. The override fraction is the number of overriders relative to the population that received the signal. For 2005, with the full program population, we know for certain the override fraction for the whole program. Once again, this is an advantage over the previous two years when override percent had to be estimated. See those previous reports for a full explanation of the options for working without the full program data.

Fraction Zero Use

Units that are never used during weekdays over the entire summer do not contribute to savings from this program at any time. We determined the fraction of zero users based on analysis of the metered air conditioning data. This fraction is determined from the full usable metering sample, not just those in the re-set group on the particular day a re-set occurred. The full sample is the largest group for which we can estimate this population characteristic. For 2005, this group includes both the curtail groups and the ex-participants.

Only "summer non-zero users" can be potential contributors to impacts. They are those units that were used on a weekday at some time over the summer. Included in this group may be some units that had zero use on a particular re-set day. We do not attempt to estimate a zero use fraction separately by re-set event. The effects of zero use by a subset of those who are at least sometimes non-zero users are included in the average impacts estimated for the non-zero use group.

Potential Contributors and Non-contributors

Estimating Percent of Non-contributors

The combined percent non-contributors is estimated as:

$$p_{NC} = p_F + (1\text{-}p_F)(p_{OR} + p_z),$$

where

p_{NC} = fraction of units that are non-contributors,

p_F = fraction of units that had signal failure,

p_{OR} = fraction of units that overrode out of those that did not have signal failure, and

p_z = fraction of units with zero weekday AC usage all summer.

That is, all units with signal failure (p_F) are non-contributors. Of the remaining units ($1\text{-}p_F$), those that cannot contribute to savings are those that override (p_{OR}) and those that were never used (p_z).

These proportions are additive because they are essentially mutually exclusive. Whether a unit has zero use is assumed to be independent of whether or not the signal was received.

Other than 2002 when there was a single program event, 2005 is the first year we have been able to use this calculation in its original form. For the 2003 and 2004 analyses, this calculation of the fraction of non-contributors could have been used; however, the true override and non-responding fractions from the full population were not available. In each case, percents were estimated using the largest appropriate group available. Furthermore, because the override rate could only be determined by the sample group itself, there was, in fact, no advantage to including them in the percent of non-contributors. To this end, the percent non-contributors actually only included non-responders and zero AC users.

We discuss the 2004 method briefly because results using the 2004 approach will be generated for the 2005 program. This will allow for comparisons across the last three years of the program with results produced from the same methodology. A full discussion of the 2004 methodology can be found in the 2004 evaluation report.

Standard Error Calculation

The primary contribution of the original methodology lies in the standard error calculation for the percent non-contributors. The participant-specific event data indicates the actual status of each participant. With full program events as took place in 2005, the percent of non-responders and overriders in the program is known. Only the percent zero users (p_z) are estimated and thus enter the percent non-contributor standard error equation with an associated variance. The standard error is calculated as:

$$SE(p_{NC}) = (1-p_F)SE(p_z) = (1-p_F)(p_z*(1-p_z)/n_z)^{1/2},$$

Equation 2-1

where n_z is the number of premises in the combined samples or, alternatively, the denominator of the fraction that provides the percentage of non-users, p_z.

This standard error calculation stands in comparison to the calculation used with limited population re-set events. Without full program events, the percent override and percent non-response are also estimates. As a result, the standard error of the non-contributor fraction is calculated as:

$$\begin{aligned} SE(p_{NC}) &= SE(p_C) \\ &= [(1-p_F)^2(1-p_z)^2SE^2(p_{OR})+(1-p_z)^2(1-p_{OR})^2SE^2(p_F) \\ &\quad +(1-p_F)^2(1-p_{OR})^2SE^2(p_z)]^{1/2}. \end{aligned}$$

Equation 2-2

For the 2004 analysis there were not full program data. We followed the original proposed methodology where possible recognizing that the advantages of that method could not be completely leveraged. For reasons related to the ease of calculating the potential contributor impact, we used an estimate of the percent *responding users* combining only the non-responders and zero AC user. Both components of this percent were estimated and thus had associated variance. This standard error for responding users was calculated as:

$$\begin{aligned} SE(p_{RU}) &= SE[(1-p_F)(1-p_z)] \\ &\simeq [(1-p_F)^2 SE^2(p_z) + (1-p_z)^2 SE^2(p_F)]^{1/2}. \end{aligned}$$

Equation 2-3

The standard errors of the proportions are calculated using standard formulas for proportions from a simple random sample.

2.2.2 Impact Estimates on Re-set Days

Overview

Estimating demand impact is an exercise in divining what would have happened in the absence of the program. For this analysis, we split the meter sample and only re-set one group for any given event. If the two groups were completely identical, then we could simply use the comparison group load as our estimate of what the re-set group load would have been in the absence of the program. Taking the difference of the two groups' mean load would provide a good estimate of demand impact. Of course, in reality, it is impossible to select two identical sample groups. Alternating curtailments between the sample groups ought to control for some of the differences, but that in turn implies conditions are the same across curtail days, and we know this was not the case.

Another possible approach to estimating the demand impact involves using a regression-based estimate of the load on the re-set days. This approach provides a different estimate of demand unaffected by program re-sets but relies on the assumption that re-set day consumption can be fully explained by the model.

The original methodology proposed for the Smart Thermostat evaluation combines these two approaches to estimating demand impact. The combination overcomes the weaknesses of each approach when used alone. The regression-based model controls for differences across the two sample groups and across re-set days. At the same time, the use of a comparison group controls for re-set day conditions not addressed by the regression-based estimates. We will refer to this approach as the "comparison group approach."

For 2005 we have developed, in addition to the original methodology, an alternative methodology that does not require a comparison group. This approach makes it possible to evaluate the two events where the full sample was re-set. In addition, it provides an alternative estimate for the remaining events by ignoring the comparison group that does exist. This approach uses the regression-based approach and addresses the limitations discussed above with a different kind of correction. We will refer to this approach as the "self-correction approach."

Load Model

The basic weather normalization model estimates load as a function of drybulb temperature, specifically, average daily heating or cooling degree-days. Using hour-specific dummy variables, the intercept and both degree-day measures are included in the model on an hour-specific basis. This means that each of the 24 hourly load measures for each day are regressed against an hour-specific intercept term and degree day term. The resulting parameter estimates, though based on only a single daily temperature measure, provide an hourly estimate of load as a function of weather.

Degree-days are calculated as the degrees above or below a base temperature. The ideal cooling base temperature is the minimum ambient temperature at which AC use begins and below which there tends to be no AC load. The heating base temperature is the maximum ambient temperature above which there tends to be no heating-related load. Base temperatures vary across premises because the inhabitants have different inside temperature preferences and houses are varied in their physical properties that relate to inside temperature. Our model estimates the same model across a wide range of cooling and heating degree-day bases and chooses the combination with the greatest explanatory power.

Equation 2-4 shows the model in equation form. It was fit separately for each premise to the AC or whole-house consumption data. Hourly AC and whole-house loads are calculated by summing the 15-minute interval data to the hour. The optimal combination of cooling and heating base temperatures was then chosen on the basis of the maximum R-square statistic.

$$L_{jdh} = \alpha_{jh} + \beta_{Hjh} H_d\left(\tau_{Hj}\right) + \beta_{Cjh}\, C_d\left(\tau_{Cj}\right) + \varepsilon_{jdh}$$

Equation 2-4

where

L_{jdh}	=	sum of 15-minute interval AC consumption at hour *h* of day *d* for premise *j*;
$H_d(\tau_{Hj})$	=	heating degree-days at the heating base temperature τ_{Hj} for premise *j*, on day *d*, based on daily average temperature;
$C_d(\tau_{Cj})$	=	cooling degree-days at the cooling base temperature τ_{Cj} for premise *j*, on day *d*, based on daily average temperature;
ε_{jdh}	=	regression residual;
α_{jh}, β_{Hjh}, β_{Cjh}	=	coefficients determined by the regression; and
τ_{Hj} τ_{cj}	=	base temperatures determined by choice of the optimal regression.

The degree-day variables are calculated as:

$C_d(\tau_{Cj})$ = max((T_d - τ_{Cj}),0)

$H_d(\tau_{Hj})$ = max((τ_{Hj} - T_d),0),

Equation 2-5

where T_d is the "daily average temperature," calculated as the mean of the daily minimum and maximum for day *d*. Because of thermal lags in the house, this form of daily average tends to be a better predictor of heating and cooling loads than the current hourly temperature, or an average for particular hours of the day.

An alternative approach considered was to use lagged hourly temperature variables in the cooling model. This approach can be effective. However, hourly lag effects get confounded with time-of-day effects so that it may be difficult to obtain meaningful hourly coefficients if lag terms are also included. Using coefficients that do not vary by hour doesn't allow behavioral effects to be captured. The hourly coefficients β_{jh} account both for different behavior by time of day and also for the effects of thermal lags within the day.

For the 2004 and 2005 analyses we have included a day lag variable. In addition to 24 hourly cooling parameters based on cooling degree days ($C_d(\tau_{Cj})$), we estimated 24 hourly cooling parameters based on a lagged temperature variable. The lagged cooling variable was a geometric combination of the previous three days' temperature. It was calculated as:

$$Tlag_d = \sum_{i=1}^{3} T_{d-i} e^{-i/3} \Big/ \sum_{i=1}^{3} e^{-i/3} .$$

Equation 2-6

Lagged cooling degree days are then calculated as with the other degree day calculations:

$$Clag_d(\tau_{Lj}) \quad = \quad \max((\mathrm{Tlag}_d - \tau_{Cj}),0).$$

Equation 2-7

The resulting load model, shown in Equation 2-8 is identical to Equation 2-4 in structure except that it includes the additional 24 lagged cooling parameters.

$$L_{jdh} = \alpha_{jh} + \beta_{Hjh}\, H_d\left(\tau_{Hj}\right) + \beta_{Cjh}\, C_d\left(\tau_{Cj}\right) + \beta_{Ljh}\, Clag_d\left(\tau_{Lj}\right) + \varepsilon_{jdh} .$$

Equation 2-8

This model explicitly accounts for thermal effects across days while still providing good estimates of behavior during the day.

Using regression coefficients from this fitted equation as indicated in Equation 2-9 by the overscript '^', and cooling, lag cooling, and heating degree-days [$C_d(\tau_{Cj})$, $Clag_d(\tau_{Lj})$, and $H_d(\tau_{Hj})$] for day *d* of the re-set event, the estimated load (without re-set) L_{jdh}, was calculated for each premise, day, and hour.

$$\hat{L}_{jdh} = \hat{\alpha}_{jh} + \hat{\beta}_{Hjh}\, H_d\left(\hat{\tau}_{Hj}\right) + \hat{\beta}_{Cjh}\, C_d\left(\hat{\tau}_{Cj}\right) + \hat{\beta}_{Ljh}\, Clag_d\left(\hat{\tau}_{Lj}\right).$$

Equation 2-9

A second adjustment made to the weather normalization model applied only to the AC-only model. The basic weather normalization model estimates a base load as well as heating and cooling parameters. For the AC-only model, we would expect this base load to be zero unless the AC unit is actually a heat pump or, as mentioned above, there is some ongoing, low-level load used by the condenser. In instances where the basic weather normalization model produced base load parameters that were, in aggregate, negative, we set the base load parameters to zero. This restricted weather normalization model is identical to the basic weather normalization model shown in Equation 2-4 except that it lacks the α_{jh} parameters.

The Comparison Group Approach

Any load model will have some estimation error. The particular model used in this analysis is relatively simple, using just the time of day, the daily average temperature, and now a lagged temperature variable. Effects of humidity, sunshine, and wind are not explicitly modeled.

Because of some of these physical factors, a portion of the modeling error for a given day and hour will be similar across AC units. The model may simply not have enough hot day data to estimate usage on the hottest days. Alternatively, if the day is very breezy, usage might tend to be lower than the temperature model would indicate. Further, even with a more sophisticated physical model, there may be behavioral changes related to events in the news or holiday schedules that would be similar across homes.

The use of the comparison group provides a basis for correcting these systematic modeling errors. We take the average modeling error for the comparison group as an estimate of the likely average modeling error for the re-set group.

First we have to calculate an "uncorrected" impact estimate for the re-set group:

$$S_{Rh} = \frac{1}{n_R}\sum_{j\in R}\left(\hat{L}_{jh} - L_{jh}\right),$$

Equation 2-10

where

S_{Rh} is the uncorrected load impact estimate of the re-set group,

$\hat{L}_{jh}$ is the weather normalized estimate of hourly load,

L_{jh} is actual hourly load, and

n_R is the number of units in the re-set group.

The model estimates for each premise tell us what would have happened without the re-set. The differences between predicted and observed load for each premise are the estimated uncorrected savings. The premise-level impacts are averaged over the group to get the mean uncorrected load impact estimate per unit. This estimate is still "uncorrected" because no comparison-group adjustment has been made.

The model estimate does not need to be perfect, only consistent, across the two sample groups. With this assumption, the average modeling error, or what we are considering the error correction, is, in fact, the same calculation for the comparison group.

$$S_{Ch} = \frac{1}{n_C} \sum_{j \in C} \left(\hat{L}_{jh} - L_{jh} \right),$$

Equation 2-11

where

S_{Ch} is the "uncorrected load impact estimate" of the comparison group, and

n_C is the number of units in the comparison group.

If the weather normalization model were perfect, the model estimate for each comparison premise would be identical to the observed load. The mean "impact" across the comparison group, S_{Ch}, would equal zero and there would be no correction. However, we do not expect the model to be perfect. We use the comparison group average error to estimate the average error for the re-set group. Thus, the comparison group average modeling error indicates if the model tends to be high or low and by how much. The correction is made by taking the difference of these two differences.

$$S_h = S_{Rh} - S_{Ch}.$$

Equation 2-12

If the model, on average, over-estimates the comparison group's actual load for a particular interval, then it will also give too much impact credit to the re-set group. In this case, the error adjustment will be positive and will be subtracted from the inflated re-set group estimate. If the model is low, a negative error adjustment is removed (a double negative) so the original re-set impact estimate is increased.

This "difference of differences" approach combines the model estimation and comparison group approaches to determine "what would have been." This approach we refer to as the "comparison group" approach as it takes advantage of the comparison group.

The Self-Correction Approach

The self-correction approach starts with same uncorrected re-set group impact estimate as the comparison group approach. For each re-set group member, the observed load is subtracted from the modeled load. The same concerns about the appropriateness of the model estimates for that particular day still exist, thus a correction is desirable. If a comparison group is not available for this event, we cannot generate a comparison group-based correction for each interval. The self-correction approach derives a single correction for the re-set period using the two hours prior to the re-set period. The mean difference between modeled and observed load during that period is used to correct each interval of the re-set period for that day.

The correction is calculated:

$$A_j = \frac{1}{n_h}\left[\sum_{h\in P}\left(\hat{L}_{jh}\right) - \sum_{h\in P}\left(L_{jh}\right)\right], j \in R$$

Equation 2-13

where

A_j is the additive correction factor,

P is the two-hour period prior to the re-set event, and

n_h is the number of intervals in period P.

The self-corrected load estimate, then, is calculated:

$$S'_h = S'_{Rh} = \frac{1}{n_R}\sum_{j\in R}\left(\hat{L}_{jh} - A_j - L_{jh}\right),$$

Equation 2-14

where S'_h and S'_{Rh} are the self-corrected impact estimates.

Just as the comparison group correction is justified with certain assumptions, the self-correction approach is also dependent on assumptions. This approach assumes that on average the two hours prior to the re-set period are representative of the load during the re-set period. It also assumes that the correction should be applied additively to the intervals of the re-set period rather than multiplicatively as a proportion. These are standard corrections used in the application of demand response baselines. KEMA research on baseline adjustments recommends the additive adjustment as more simple and less prone to scaling errors.[1]

Savings Estimates by Time Interval

The load model is estimated on an hourly basis, and the savings equations above indicate estimates for each hour. However, the load data were available on a quarter-hour basis. Kilowatt-hour savings for each quarter-hour interval were calculated analogously to the hourly equations indicated above. For the quarter-hourly estimates, the load in each time increment was estimated using the load model coefficients for the hour that included that increment.

[1] KEMA Inc. *Final Report: Protocol Development for Demand Response Calculation, Findings and Recommendations.* Prepared for California Energy Commission. February 13, 2003.

Savings were also calculated for the average of the entire re-set period. The re-set periods are all listed as starting and ending on the hour. Apparently, though, the actual start and end times are slightly offset so as not to have too extreme a system spike when the group is returned to full cooling. Despite this we only consider intervals within the specific curtail period.

For the overall re-set period savings, each AC unit's average observed load during the re-set period was calculated across all increments in the period. Each unit's estimated load was similarly averaged across all re-set period time increments. Both the comparison group and self-corrected approaches can take advantage of these re-set period average kW savings.

Final Impact Estimate

Not all AC units in the program have the potential to provide savings during a re-set event. At this point, we have identified what percent of the total units are potential contributors. We have also calculated an initial estimate of the load impact of the re-set event for these potential contributors. It remains to put these two pieces back together to produce a per-unit impact estimate for all units in the program. It is also important to understand, in theory, why this three-step methodology should provide more accurate results than a direct approach.

The program per-unit average impact estimate is calculated by multiplying the average impact estimate for the potential contributors by the fraction of units in this category. Thus, for example, if only one-quarter of the units in the program are determined to be potential contributors to savings, that group's estimated per-unit savings is multiplied by one-quarter to spread the savings per unit across all units in the program. Thus, the final impact S_{Th} for each interval h is given by:

$$S_{Th} = p_C\,(S_h),$$

Equation 2-15

where S_h (or S'_h) is the corrected average impact as defined above.

This is a simple weighted sum combining potential contributor savings with non-contributor savings. As the non-contributor group is assumed to have impacts of zero, they drop out of the equation.

The most direct approach to calculating program per-unit impact would be simply to calculate savings directly over all units, both contributors and non-contributors, in the metered samples. With this approach, however, the fraction of zero contributors in each metered group is random. This random variation in the proportion of zero contributors in each group adds to the variance of the estimated savings.

Focusing the analysis on potential contributors does not in itself guarantee more accurate results. Whatever reduction there is in the variance of the impact estimate will be replaced by the variance associated with the potential contributors' percentage. In fact, if only the sample group is used to estimate the potential contributor's percentage, then the results will be a wash. The Smart Thermostat event data, however, changes this equation.

Utilizing the full program event data, we know for certain the percent of units in the whole program that are non-contributors due to non-response or override. By incorporating this information into the percent non-contributor calculations, the overall variance of the final impact estimate is reduced.

Standard Error of the Impacts

The standard error of the impact estimate is calculated from the separate standard errors of the percent contributors, p_C, and the savings per unit, S_h, for this group.

The corresponding standard error is calculated for each interval by first calculating the standard error of each group's difference between observed and modeled load. This standard error is simply the standard deviation of individual units' modeling errors divided by the square root of the number in the group. The standard error of the difference of differences (comparison group approach) impact estimate, $SE(S_h)$, is the square root of the sum of squared standard errors for the re-set and comparison groups.

The standard error of the final estimate S_{Th} is then:

$$SE(S_{Th}) = [p_{RU}^2 SE^2(S_h) + S_h^2 SE^2(p_C)]^{1/2},$$

Equation 2-16

where the calculation of the standard error of the proportion was given above.

Assessing Comparability of the Comparison Group

The comparison group correction approach assumes that the modeling error for the comparison group is a good indicator of the likely modeling error for the re-set group. Thus, an important step prior to applying this method is to assess whether the two groups are in fact similar.

Premises were selected at random for the metering sample and were randomly assigned to Group A or B. Thus, there was no *a priori* reason the groups should have been different. However, random effects could result in observable differences at the outset that would suggest a need for some kind of adjustment.

A particular concern was that the sizes of the air conditioning units in the two samples might be different. In this case, the comparison group error might be a good indicator of the re-set group error, but a scaling factor might need to be applied to the comparison group error to adjust for the size difference. Our original plan was to calculate savings after normalizing the two groups' observed and estimated loads by dividing by their respective average air conditioner capacity in tons.

The 2002 analysis decided the two groups had practically the same distribution of AC unit size, and this normalization was not necessary. That analysis compared the two groups in terms of the mean, median, minimum, maximum, and standard deviation of tons, both for the full sample and for the smaller sample used in different stages of the analysis. In terms of these distribution statistics, the two groups were very similar to one another and were similar also across the different subsets used in the analysis. This comparison is repeated for the groups used in the 2005 analysis.

An additional check is also repeated. It plots the average re-set group model error against the average comparison-group model error for warm weekday afternoons excluding the re-set day. This plot is presented in Section 3.

Even with very comparable groups, normalization by capacity could be considered as a variance reduction technique. Ratio estimation, such as calculating savings per ton rather than mean savings per unit, can often be effective in reducing the variance of impact estimates. However, for this method to be effective in variance reduction, it is necessary to have the normalization variable known for the entire population. In this study, capacity data were collected for the metering sample to allow for scaling between the re-set and comparison groups if necessary. Capacity data are not available for the general population of participating AC units. Thus, once it was determined that scale adjustment was not required between the two groups, no normalization by capacity was used in calculating the savings estimate.

Whole-premise Analysis

For each re-set event, the same analysis method was applied to the whole-premise data as the AC data. The same units identified as potential contributors by the end-use analysis were included in the whole-premise analysis.

In previous years, the whole premise analysis was found to be less reliable in terms of the standard errors of the resulting estimates than was the AC analysis. We therefore relied on the AC results for the impacts. The results presented in Section 3 show that, for 2005, the whole-premise results appear to be as reliable as the AC results.

2.3 Projected Impact Estimates for General Conditions

This section describes the methods by which demand impacts are estimated under general conditions. A general condition can be defined by as little as daily average temperature but can include additional information such as hour of the day and duration of the event. The method for general conditions uses the same load models as described above. Rather than comparing estimated load to actual load, we applied a theoretical model of equivalent temperature differences to describe the effect of re-set. This approach can be used to estimate potential contributor impacts. These projections can be adjusted taking into consideration actual or estimated non-response, override, and zero usage percents.

2.3.1 Model AC Loads at Different Temperatures

The load models described above to estimate load *without* re-set were used here to estimate load both with and without re-set. Loads *with* re-set were estimated using the daily average temperature less the thermostat setback. This in effect lowers the average daily temperature and thereby decreases the cooling load. That is, the effect of setting the thermostat forward by δ degrees is essentially the same as the effect of dropping the ambient temperature by δ degrees. The magnitude of the thermostat set-forward, in degrees Fahrenheit, thus was a critical determinant of the load with re-set.

The lagged temperature variable must also be provided for the projection model. One could simulate a variety of situations depending on the choice of the lag variable. Finally, the demand impact estimate for a single premise is calculated as the difference between the two loads, with and without re-set.

2.3.2 Accounting for Non-contributors

Impact projections provided by the weather normalization load models are for potential contributors. As with the impact estimates above, these potential contributor estimates must be adjusted to account for non-responders, overriders, and zero AC users. The non-response and zero AC user percents, for the purposes of projection, are effectively constant. We use the average across the 12 re-set events for the non-response percent. The zero AC usage percent is already a single percent as used for the impact adjustments. The override percent is more challenging for the projections because override is clearly a function of temperature, re-set duration, time of re-set, and the re-set increment.

Modeling the Override Rate

For the 2005 analysis, override rate is modeled using a survival analysis approach[2]. Survival analysis is widely used in disciplines where it is of importance to measure how much time passes before an event occurs. In the biological and medical sciences, survival analysis is frequently used to measure time until death under different circumstances. This common usage gives the technique its name. The technique is also commonly used in product engineering to measure time until failure.

For our purposes, survival analysis offers an approach similar to the log odds approach used in the 2004 analysis while taking advantage of more of the available information and providing greater flexibility in the shape of the curve. The log odds approach used in 2004 fits a logistic distribution curve similar to the classic cumulative normal S-shaped curve to data points representing override percentages for different events. For the 2004 analysis, we fit this model with 24 data points representing the 24 events in 2003 and 2004.

[2] Allison, Paul D. 1995. *Survival Analysis Using SAS: A Practical Guide*. Cary, NC: SAS Institute Inc.

In comparison, the survival analysis approach uses each individual unit for each event as data to estimate the probability of over-riding as an event progresses. That is, for each unit and event, we observe the time until override, if it occurred, or the time until the end of the control period with no override. For 2005, with full program events data, we have literally thousands of data points.

Parametric Models

The parameters of the distribution of the time to override are estimated by fitting a general linear regression model to the log (natural) of the times to override of units observed in the data. This model can be written as:

$$\log(Y_j) = \gamma x + \sigma\varepsilon_j ,$$

Equation 2-17

where

Y_j = observed time to override of unit j,

γ = intercept and parameters to be estimated,

x = covariates for unit j

σ = scale parameter, and

ε_j = random error term.

The exponential of the error term of this model (e^{ε_j}) is assumed to follow the standardized form of the distribution of the time to override of a unit. The general linear regression model is fitted by maximizing the log-likelihood function for the assumed distribution.

The estimated parameters of the covariates and the distribution of the time to override of a unit define a survival function. This function is simply one minus the cumulative distribution function of the time to override or *“failure” of* a unit. The survival function $S(t;\theta)$ gives the probability of not overriding until at least time t given the parameter vector θ. Probability of override for event of duration t^* given other conditions and/or characteristics x is:

$$Pr(override|t^*,x) = S(t^*|x, \hat{\theta}).$$

Equation 2-18

We evaluate this function using the estimated survival model parameters $\hat{\theta}$ at varying durations t^* and temperature conditions. A different model is fit for each two-hour time of day during which control may occur.

A survival function implies a certain hazard function $h(t;\theta)$. Roughly, the hazard function can be thought of as the probability of overriding at time t given the unit has not overridden up to that time. Formally, it is the negative ratio of the survival probability density function *dS/dt* to the survival function,

$$h(t;\theta) = -\frac{dS/dt}{S(t;\theta)}.$$

Equation 2-19

An increasing hazard function means the override rate increases as an event progresses, whereas a decreasing hazard function means the override rate decreases as an event progresses. If the hazard function is constant, the override rate remains constant as an event progresses.

Traditional survival analysis, sometimes referred to as parametric survival analysis, is limited in its distributional choices. The distributional choice determines the potential shapes of the hazard function, thus, is of fundamental importance to the analysis. On the other hand, there is only limited statistical basis for choosing among the different distributions.

The Proportional Hazards Model and Recurrent Events

These limitations using parametric distributions led to the development of a new semiparametric model called the proportional hazards (PH) model. It can be written in terms of the logged hazard function:

$$\log h(t) = \alpha(t) + \beta x,$$

Equation 2-20

where $\alpha(t)$ represents a baseline hazard function that need not be defined.

Depending on how it is defined, the PH model can be identical to some of its parametric cousins, but is not limited to their particular forms. This provides the model its flexibility with regards to distributional assumptions. The partial likelihood approach cleared the way for this now very popular approach to survival analysis.

The analysis of recurring events adds an additional complication to the basic survival analysis framework. When the event data used is time until death, recurrence is not a complicating factor. The classic recurring event examples remain in the medical sciences. The modeling of recurring heart attacks or other health events has been a prime motivator in the development of recurring event models. There are two essential facets to the recurring events analysis.

Dependence must be assumed among events happening to the same patient (in the classical survival model application) or AC user (in our case). We would expect override behavior to have an individual flavor. If Smart Thermostat participant A overrides 6 of 12 events and participant B overrides 1 of 12 events, we would expected them to have different probabilities of override on a subsequent event. There is also time or ordinal dependence. That is, the outcome of the second override is in part dependent on the outcome of the first event.

Unfortunately, recurring AC re-set events have characteristics that are uncommon in the recurring events literature. Most recurring events analyses define duration as the time since the previous event (such as survival since the last heart attack). This is not the case with event re-sets. While the interval between re-set events might be important, there is, in fact, no chance of override until the re-set occurs. In fact, the interval between re-set events might actually be more important than the simple order of re-sets. An override occurring yesterday would seem more relevant to a decision to override today than an override a month ago. Incorporating interim periods substantially increases the complexity of the analysis.

Given the issues present in the Smart Thermostat scenario and the limitations on the scope of this analysis, the model used addresses only the first of these issues, dependence. Furthermore, only the standard error is corrected for dependence. In the proportional hazards model, it is possible that parameter estimates are biased toward zero as a result of dependence. While this bias cannot be directly addressed, model diagnostics do allow us to determine that the downward bias is minimal.

2.3.3 Comparison with Actual Re-set Events

The impact estimates developed for the individual re-set events were compared to projections estimated using this more general approach, with the corresponding average temperatures and re-set amounts. If the projections were consistently high or low, a suitable calibration could be devised for the projection model.

3 FINDINGS

This section describes the findings of the analysis of the metered consumption data and the re-set event data for Summer 2005. In section 3.1, we describe the weather experienced in San Diego during the summer of 2005 relative to previous years. In Section 3.2 we identify the data used in the analysis. We also identify which units belong to the different categories related to usage and event day behavior. In Section 3.3, we put the components together to determine the percent non-contributor for each re-set event. Section 3.4 discusses the load model validation. In section 3.5 we work through visual examples of both approaches to estimating impacts and report the impact results. This section also includes a discussion of the different approaches as well as results for the two event days with no comparison group. Section 3.6 presents impact projection results, including the results from the new approach to estimating override by survival analysis methods.

3.1 2005 COOLING SEASON WEATHER

Temperature is the primary driver of AC use in San Diego and, thus, the primary driver of potential program savings. The 2005 cooling season as a whole proved to be cooler than the two previous summers. Table 3-1 compares the cooling season of 2005 to the two previous cooling seasons for three different temperature-related weather indices. The first three columns compare the whole cooling season including weekends. The 2005 cooling season was cooler based on average temperature, cooling degree-days, and the number of days above 77° Fahrenheit.

Table 3-1
Weather Indices for Cooling Seasons, 2003 to 2005

Weather Indices	Summer			Re-set Days		
	2003	2004	2005	2003	2004	2005
Average of Daily Average Temperatures	69	69	68	73	76	75
Cooling degree days (base 65)	983	849	757	110	137	119
Number of Days with Average Daily Temperature greater than 77	9	7	6	1	3	3

*Cooling season runs from May through October

The impact evaluation is based on the actual re-set events that occurred during the cooling season of 2005. The last three columns compare the same temperature indices for the re-set event days only. The 2004 program had 13 re-set days compared to the 12 in either 2003 or 2005, so the cooling degree-days and number of days are a sum and count across one additional day. Nevertheless, despite the 2005 cooling season being substantially cooler on the whole when compared to 2003, the 2005 event days were decidedly warmer. This indicates that re-set events coincided with hot weather more consistently than in previous years. In fact, the extent to which re-set events happened on the hotter days of the season can be seen in the following plots.

Figures 3-1 through 3-5 show the average day temperature for the seven weather stations represented in the sample for June through October. The variability across weather stations is clearly evident in these plots. Vertical lines indicate the days on which thermostat test re-sets took place.

Figure 3-1

June, 2005 Day Average Temperatures

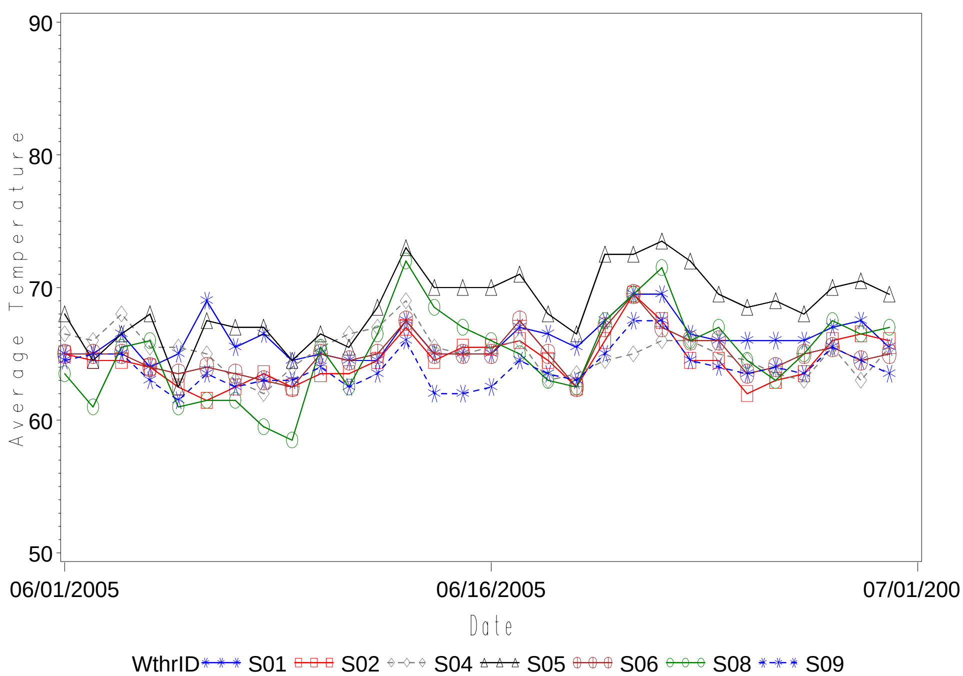


Figure 3-2

July, 2005 Day Average Temperatures

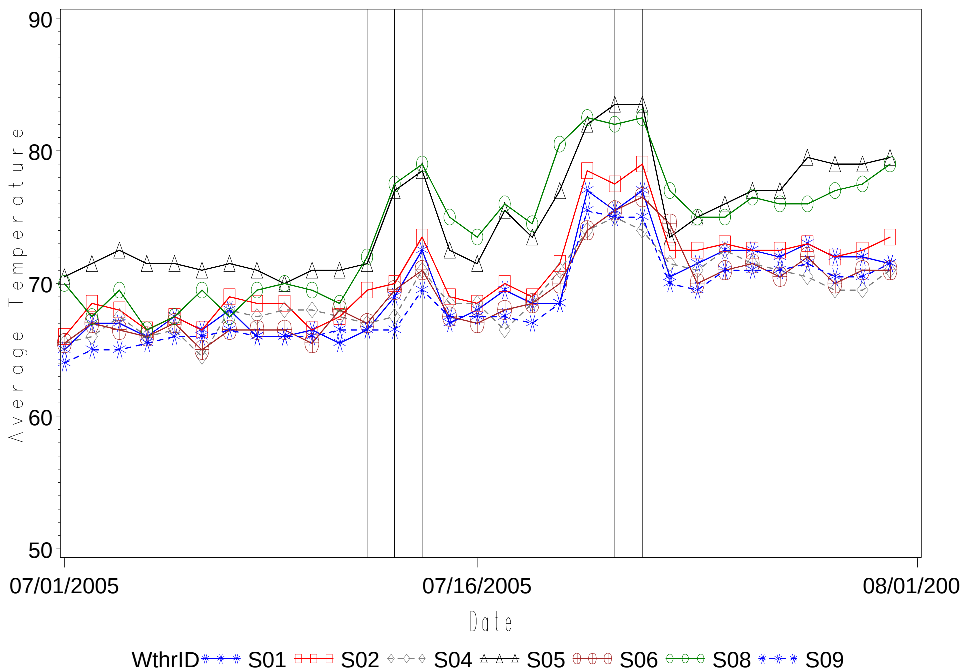


Figure 3-3

August, 2005 Day Average Temperatures

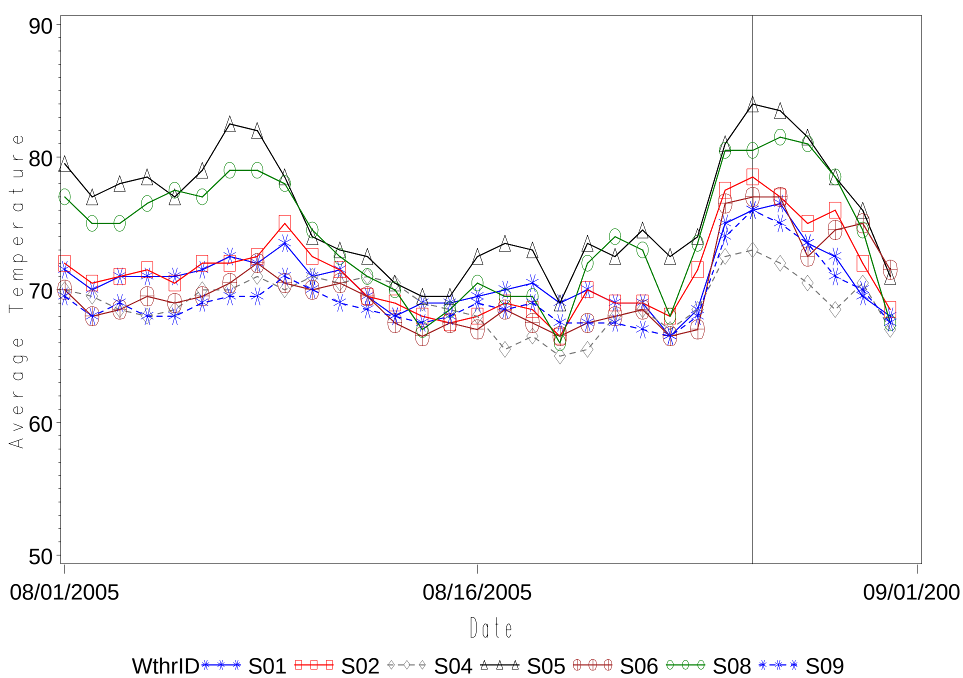


Figure 3-4

September, 2005 Day Average Temperatures

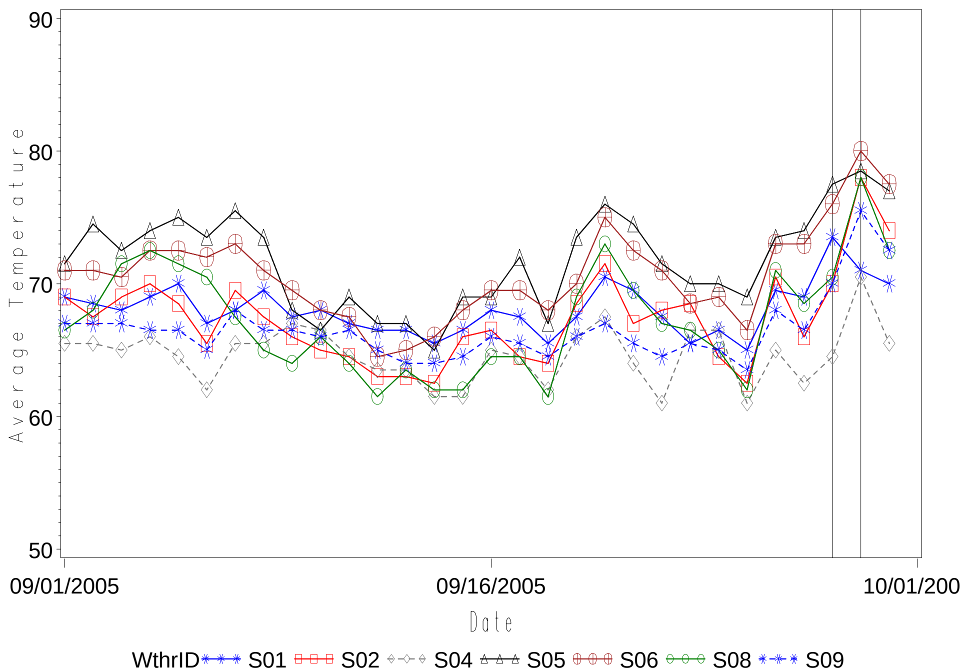
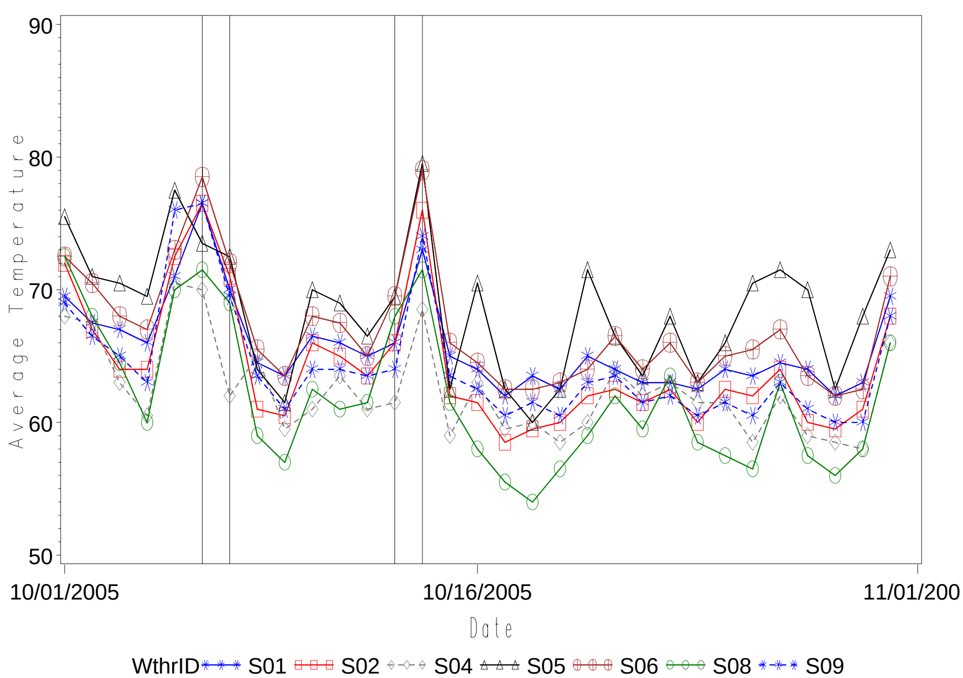


Figure 3-5

October, 2005 Day Average Temperatures



3.2 Units Used in the Analysis

3.2.1 Identifying Participants by Group

One hundred sites were originally chosen for the Smart Thermostat Program sample. As of the start of the fourth summer of the program (July 1, 2005), only 58 of the original 100 evaluation sample participants were still being re-set with their sample group and generating interval data. These sites, representing 63 thermostats, continue to function as they did when this evaluation began four years ago.

An additional 29 participants from the original evaluation sample continue to generate interval data, but are no longer re-set with their sample group. The majority of these (27) left the program and are no longer re-set during re-set events. They represent a dedicated comparison group; a group of units that will always be included with the designated comparison group for that re-set day. There are also two other participants in a dedicated re-set group. They have been removed from their sample group and are now re-set with the full program group for all events.

Table 3-2 describes the distribution of sites, thermostats, and AC units for the original 100 evaluation sample participants.

Table 3-2
Sites Included in the 2005 Impact Report

Participant Status	Sites	Thermostats	AC Units
Original Sample Group A	29	31	30
Original Sample Group B	29	32	32
Dedicated Comparison Group	27	31	30
Dedicated Re-set Group	2	2	2
Not Included	13	17	17
Total	100	113	111

3.2.2 Identifying Meters with Good Data

Of the original 100 participants, 87 sites provided acceptable 15-minute interval energy consumption data for our analysis. The 13 sites were removed from the analysis for two different reasons. Table 3-3 shows the breakout for sites, thermostats, and metered AC units.

Table 3-3
Sites, Thermostat, and Metered AC for Removed Sites

Participant Status	Sites	Thermostats	AC Units
Left program but still randomly re-set	6	8	8
Interval data Missing	7	9	9
Total	13	17	17

The complete interval data for 93 sites was received from SDG&E. The data spanned seven months from April 2004 through October 2005. The interval data were not sent for two customers where metering equipment was removed. In addition, five other sites had either AC or WH data missing for at least part of the year. Of these seven sites, four were ex-participants, two left during the summer of 2005, and one was still enrolled in the program.

A new category of problematic data arose in 2005. A number of sites were re-set on schedules other than expected given their program status. The source of this problem appears to lie in the difficulty of tracking individuals out and then back into the program. The Silicon Energy portal does not provide a start date for individual participation. Only a “removed” date is provided. Furthermore, where an ex-participant returns to the program, there is not a consistent reassignment to the original sample group. Sometimes, ex-participants return to their original group. Other times they are put in the general program group and re-set for all events. Finally, there are three ongoing participants that were reclassified to the general program group.

The Silicon Energy event data reflects actual program activity. However, these data provide incomplete information with regards to what is happening on site. For the analysis methodology to work properly, it is essential the cooling season interval data from the site represent the usage of a single occupant. The re-set schedules of five sites indicate that this might not be the case. These five sites left the program at one point. In two instances, the event data explicitly indicates new occupants. The other three could be new occupants though the same occupant names remain in the database. A sixth site is problematic as it has two thermostats that are re-set on different schedules. In all six cases, we decided removal of the site from the analysis was necessary.

We conducted two further checks of the meter data. AC and WH usage data were compared by interval. AC usage from the AC meter should never be larger than the WH usage from the WH meter. In previous years we have removed sites because of failure to meet this criteria. This year, three sites have a handful of instances that fail the criteria. SDG&E load research personnel have checked this data and deemed it suitable for analysis. In the few instances where AC usage is greater than WH usage, both values will be set to missing.

As a final test of the interval data, we flagged zero whole-premises usage. Valid zero readings are unlikely for a whole-premises meter unless there is a system outage or construction on site. There were intervals with zero usage but no sites had widespread zero WH usage and no zero usage intervals took place on curtail days. These intervals were not included in the weather normalizing load model portion of the analysis.

In total, thirteen sites were removed from the analysis. Of the thirteen, only two have been consistent program participants through the four years of the program. This leaves 29 sites in each of the two original curtail groups, 27 more in a dedicated comparison, and two sites in a dedicated re-set group.

3.2.3 Units Included in Each Analysis Component

As described in Section 2, the AC units were classified as either “non-contributors” or “potential contributors” for each re-set day. Sites that had zero usage on all summer weekdays were non-contributors for the whole scope of the analysis. Participants who did not receive the re-set signal for a particular event, or who overrode the re-set signal once it was received, were considered non-contributors for that event. Thus, for any particular re-set event, potential contributors were those with successful signal receipt, no override, and non-zero usage during summer weekdays.

Identifying AC Non-users

AC non-users were identified by the absence of AC data indicating more than minimal AC use during weekday afternoons. AC use was defined as a quarter-hourly consumption observation greater than 0.025 kWh to allow for the possibility of continuously running case or emollient heaters in the condenser. Minimal AC use was defined as having less than one percent of quarter-hourly observations showing AC use between 10 AM and 10 PM on weekdays between May 1 and October 1.

Since only one AC energy consumption meter was used at any one site, two-thermostat sites considered non-users necessarily showed no AC use from either thermostat. If they showed AC use, it could not be discerned whether one thermostat might have been a non-user.

It has always been recognized that metering errors could result in the appearance of no AC use at any hour. The combination of AC and whole premise data makes it possible to do an informal check of the AC interval data. AC usage is generally a sufficiently large portion of a residence’s usage that the usage pattern in the AC data is clearly reflected in the whole premise data. In 2005 there were participants with no apparent AC usage but showing whole premise usage patterns that indicated AC usage. SDG&E was alerted to the possibility of metering errors in these meters. An effort was made to check these meters, but the issue was not resolved in time to be included in the results presented here. The effect of each false zero reading on an AC meter lowers the impact estimate by approximately 1 percent.

Table 3-4 provides the counts of sites, thermostats, and metered AC units for AC users and non-users in the usable sample. The full set of good meters are used to determine a single estimate of the percentage of AC non-users

Table 3-4
Sites, Thermostat, and AC Meter Count of AC Non-users

User Status	Participant Status	Sites	Thermostats	AC Units
AC Users	Original Sample Group A	25	27	26
	Original Sample Group B	24	27	27
	Dedicated Comparison Group	21	24	24
	Dedicated Re-set Group	1	1	1
Non-Users	Original Sample Group A	4	4	4
	Original Sample Group B	5	5	5
	Dedicated Comparison Group	6	7	6
	Dedicated Re-set Group	1	1	1
AC Users		71	79	78
Non-Users		16	17	16
Percent zero AC use		18%	18%	17%

Non-responding Thermostats

Non-responding thermostats were identified as non-responders by event reports available from the Silicon Energy EEM Suite Web site (sdgerem.siliconenergy.com/siliconenergy/rem/asp/event_summary_setup.asp). Non-responder thermostats had neither an acknowledgement time stamp nor an override time stamp in the event report.

Table 3-5
Comparison of Curtail Group and Full Program Signal Non-Response Rates

Re-set Date	Start Time	Sample Group	Smart Thermostat Sample Device Counts			Full Program Population Device Counts		
			Confirmed	No Response	No Response Percent	Confirmed	No Response	No Response Percent
7/12/2005	14:00:00	A	61	7	10%	3,206	222	6%
7/13/2005	14:00:00	B	31	3	9%	3,203	226	7%
7/14/2005	14:00:00	A	29	5	15%	3,198	210	6%
7/21/2005	15:10:00	B	31	3	9%	3,047	361	11%
7/22/2005	14:00:00	A	30	4	12%	3,219	189	6%
8/26/2005	14:00:00	A	30	4	12%	3,439	235	6%
9/28/2005	14:00:00	B	31	3	9%	3,274	400	11%
9/29/2005	14:00:00	A	30	4	12%	3,417	257	7%
10/6/2005	14:00:00	B	31	3	9%	3,500	436	11%
10/7/2005	14:00:00	A	30	4	12%	3,611	325	8%
10/13/2005	14:00:00	B	31	3	9%	3,494	438	11%
10/14/2005	14:00:00	A	30	4	12%	3,647	285	7%
All events			365	43	11%	36,608	3,299	8%

Table 3-5 shows the non-response rates for both the active curtail group and the program as a whole. In actuality, 6 percent of the program population never received a signal in any of the re-set events for which they were paged. The majority of these devices were paged for all 12 events.

Among devices activated part way through the summer the incidence of total non-response was much higher. Eight percent of the 309 devices added in August never responded to the seven events for which they were paged. Nineteen percent of the 263 devices added in early October never responded for all four October events.

The curtail Groups A and B had 11 and 9 percent that did not respond to the signal in any of the 12 events. While these rates are nearly double that of the overall population, because of the small number in the total sample, the difference is not statistically significant.

As discussed in Section 2, for some non-responders, the thermostat may in fact have received the signal and raised the cooling setpoint successfully, but failed to send an acknowledgement reply to the system head end. Thus, the percentage of thermostats reported as non-responders could be viewed as an upper bound on the signal failure rate. On the other hand, there could also be cases where the signal was received but the re-set did not occur. Recognizing these potential sources of over and under-statement, we treat the percent not responding to the re-set signal as the percent that were not re-set.

Overriding Thermostats

Override thermostats also were identified by event reports available from the Silicon Energy EEM Suite Web site. Override time stamps were available in those reports. The time stamp appears to indicate the time of receipt of the override acknowledgement message. Thus, there could be some delay between the time the occupant changed the setpoint and the reported override time.

Table 3-6 shows the override rates for the curtail groups and for the full program. The curtail group and full program population show a similar pattern of override. Over all 12 events, the curtail group and full program population have very similar average override percentages, 20 and 21 percent respectively. Approximately 40 percent of the program population and curtail Group A never overrode the re-set. Fifty-three percent of curtail Group B never overrode. For all groups, only a negligible percent overrode all events.

Table 3-6
Comparison of Curtail Group and Full Program Override Rates

Re-set Date	Start Time	Sample Group	Smart Thermostat Sample Device Counts			Full Program Population Device Counts		
			Confirmed	Over-ride	Over-ride Percent	Confirmed	Over-ride	Over-ride Percent
7/12/2005	14:00:00	A	61	5	8%	3206	302	9%
7/13/2005	14:00:00	B	31	7	23%	3203	447	14%
7/14/2005	14:00:00	A	29	8	28%	3198	888	28%
7/21/2005	15:10:00	B	31	7	23%	3047	1160	38%
7/22/2005	14:00:00	A	30	10	33%	3219	1256	39%
8/26/2005	14:00:00	A	30	8	27%	3439	707	21%
9/28/2005	14:00:00	B	31	7	23%	3274	674	21%
9/29/2005	14:00:00	A	30	7	23%	3417	1043	31%
10/6/2005	14:00:00	B	31	9	29%	3500	697	20%
10/7/2005	14:00:00	A	30	3	10%	3611	496	14%
10/13/2005	14:00:00	B	31	2	6%	3494	358	10%
10/14/2005	14:00:00	A	30	6	20%	3647	612	17%
All events			365	73	21%	36,608	8,028	22%

3.3 Fractions Potentially Contributing and Not Contributing to Savings

For the first time since the program began in 2002, the 2005 Smart Thermostat program had multiple full program re-set events. As a result, the original proposed methodology taking advantage of program population level data can be implemented. The population level data for non-response and override will be used to construct the fractions of potential contributors and non-contributors.

To explore the value of this approach, these fractions will also be constructed using only curtail group data. This is analogous to previous years when population level data was not available. The comparison between the results generated both ways indicates the effectiveness of the proposed methodology.

3.3.1 AC Non-users

The percentage of AC non-users is always estimated from the final set of sites with good data. Table 3-6 above indicates that 16 units were categorized as non-users out of the total of 95 metered units still in the analysis. For every re-set day, then, the fraction of AC non-users is 16/95, or 17 percent. The fraction will enter into the percent non-contributors calculation with a standard error of 0.014.

3.3.2 Non-responding Thermostats

Non-response is event-specific. Table 3-6 above shows the program level percent non-response for each re-set event in 2005. Each of these percents will enter into the percent non-contributor with no associated variance as these percents represent that actual non-response percents for the whole program.

3.3.3 Override Thermostats

Override is also event-specific. Table 3-6 above provides the program level percent overriding for each re-set event in 2005. Once again, the program population level percents are known with certainty.

For purposes of this analysis, we use the percent that overrode at any point during each event. Since overrides increase as the re-set event continues, this override percent is the maximum that occurred over the event—that is, the percent that had overridden as of the end of the event. Figure 3–6 shows the percent overriding as a function of time from the start of each re-set event.

Figure 3-6
Override Percent as Function of Time from Event Start

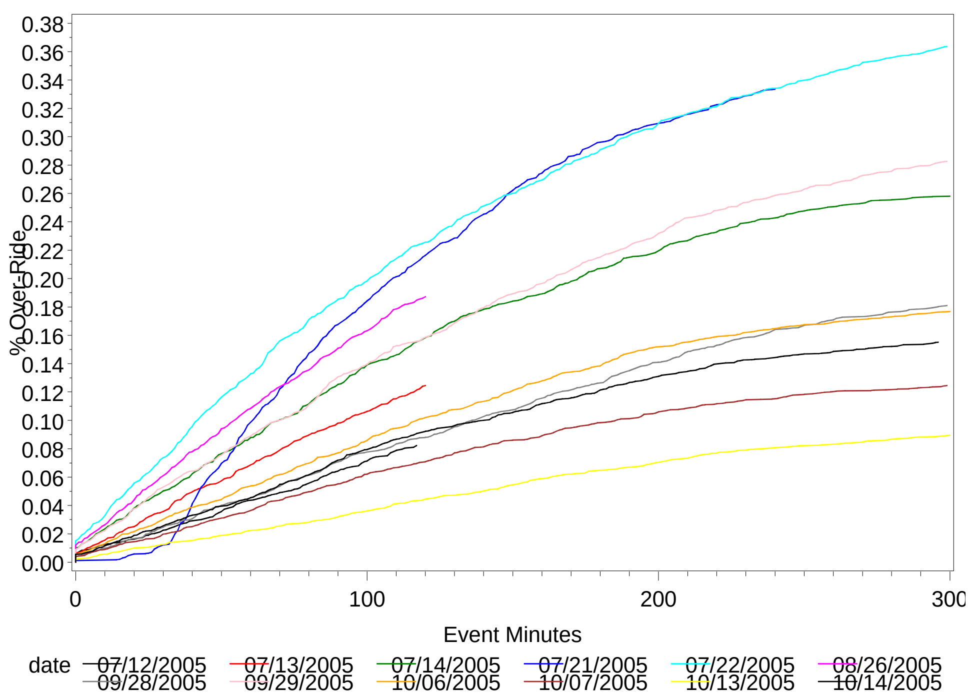


Table 3-7 shows the percent of overriders with the factors most likely to be correlated with overriding. In 2005, there was a clear correlation with average temperature. There was little variation in re-set duration and no variation in the re-set amount so the correlation in these instances is less clearly defined.

Table 3-7
Percent Override Compared to Average Temperature, Re-Set Amount, Event Duration, and Time

Date	Sample group	Start Time	End Time	Hours Duration	Degrees Setback	Average Temperature	Percent Over-ride
7/12/05	A	14:00	16:00	2	4	70	9%
7/13/05	B	14:00	16:00	2	4	73	14%
7/14/05	A	14:00	19:00	5	4	75	28%
7/21/05	B	15:10	19:10	4	4	80	38%
7/22/05	A	14:00	19:00	5	4	80	39%
8/26/05	A	14:00	16:00	2	4	80	21%
9/28/05	B	14:00	19:00	5	4	73	21%
9/29/05	A	14:00	19:00	5	4	78	31%
10/6/05	B	14:00	19:00	5	4	75	20%
10/7/05	A	14:00	19:00	5	4	71	14%
10/13/05	B	14:00	19:00	5	4	67	10%
10/14/05	A	14:00	19:00	5	4	77	21%

3.3.4 Percent Not Contributing

Table 3-8 summarizes the fraction not contributing to impacts for the 12 re-set events in the summer of 2005. As discussed, the non-responder fractions reflect the percent non-response of the full program population. The AC non-use percent is constant across the whole summer and reflects the fraction of units still remaining in the analysis with zero AC usage. The override fraction is also calculated from the full program population. The combined percent not contributing ranged from 31 to 60 percent. This rate is similar to previous years: The range was 32 to 63 percent across the 12 re-set days in 2004, 26 to 68 percent not contributing for the 12 2003 events, and 40 percent not contributing for the single 2002 re-set event. The average percent not contributing across the 12 2005 re-set events was 44 percent, in between the average percents of the two previous years.

Table 3-8
Percent Not Contributing During 2005 Re-set Events

Re-set Date	Non-Response Fraction: No Response	Non-Response Fraction: All Program participants	Non-Response Fraction: Fraction (P_F)	AC Non-use Fraction (P_z)	Over-ride Fraction: Over-riders	Over-ride Fraction: Confirmed Program Participants	Over-ride Fraction: Fraction (P_{or})	Percent Not Contributing: $P_F + (1-P_F)(P_z+P_{or})$
07/12/05	229	3494	7%	17%	307	3265	9%	31%
07/13/05	229	3463	7%	17%	454	3234	14%	35%
07/14/05	215	3442	6%	17%	896	3227	28%	48%
07/21/05	364	3442	11%	17%	1167	3078	38%	60%
07/22/05	193	3442	6%	17%	1266	3249	39%	58%
08/26/05	239	3708	6%	17%	715	3469	21%	41%
09/28/05	403	3708	11%	17%	681	3305	21%	44%
09/29/05	261	3708	7%	17%	1050	3447	30%	51%
10/06/05	439	3970	11%	17%	706	3531	20%	44%
10/07/05	329	3970	8%	17%	499	3641	14%	36%
10/13/05	441	3966	11%	17%	360	3525	10%	35%
10/14/05	289	3966	7%	17%	618	3677	17%	38%

3.4 VALIDATION OF LOAD MODELS AND COMPARISON GROUP

3.4.1 Re-set and Comparison Group Characteristics

As described in Section 2, it is necessary to compare the size distributions of the different curtail groups. The primary reason for the comparison was to determine if there was a need to scale the savings by capacity and the appropriate magnitude of the scaling. The review also would reveal anomalous units. The previous three analyses concluded there was no need for scaling with their respective sample groups. The comparison was repeated for 2005 taking into account both the updated curtail groups and the dedicated comparison and re-set groups.

Table 3-9 shows the distribution of AC unit capacity for each analysis group. The two original curtail groups are more similar than they were in the original sample. The two dedicated groups are both slightly smaller in capacity. The larger dedicated comparison group will have the effect of lessening the slight differences between the curtail and comparison groups when Group B is curtailed and increasing the capacity difference when Group A is curtailed. We tested to make sure that this disparity did not negatively affect the final results. Removing Group C from the analysis had minimal average effect on the impact estimates but did increase the variance of the estimate. The combination of these two changes resulted in two additional impact estimates not being statistically different from zero.

Table 3-9
Distribution of AC Unit Capacity (tons) by Data Scope

Data Scope	Group	Sites	AC Units	Mean	Median	Min	Max	Standard Deviation
Original Sample	A	50	56	3.8	4.0	2.0	6.0	0.8
	B	50	57	3.6	3.5	2.0	6.0	1.0
	Total	100	113	3.7	4.0	2.0	6.0	0.9
All Units With Good Data for the 2005 Analysis	A	30	32	3.9	4.0	2.5	5.0	0.7
	B	29	32	3.8	3.8	2.0	6.0	1.0
	C	27	31	3.6	3.5	2.0	6.0	1.0
	R	2	2	3.3	3.3	3.0	3.5	0.4
	Total	88	97	3.7	4.0	2.0	6.0	0.9
All Units with Good Data and Non-Zero Usage	A	26	28	3.9	4.0	2.5	5.0	0.8
	B	24	27	3.8	4.0	2.0	6.0	1.1
	C	21	24	3.7	3.8	2.0	6.0	1.0
	R	1	1	3.5	3.5	3.5	3.5	.
	Total	72	80	3.8	4.0	2.0	6.0	0.9

Group C=dedicated comparison group, Group R=dedicated Re-set group

3.4.2 Observed and Modeled Loads

Another type of method validation was examination of the quality of the load model fits for both the re-set and comparison groups. We considered both the AC end-use data and the whole-house data.

Table 3–10 summarizes key regression diagnostics for the end-use and whole-house model fits. The table indicates that the whole-house fits were generally better than the AC fits. The mean WH R^2 statistic was substantially higher though the t-statistics for the WH peak hour cooling slopes were not as high as the AC t-statistics.

Table 3-10
Mean Regression Diagnostics for End-use and Whole-house Load Model Fits

Regression Statistic		AC Data	Whole-Premise Data
Median R-Squared		0.52	0.79
Median Cooling Slope t-statistic	Hour		
	12	2.79	2.33
	13	4.70	3.62
	14	6.57	4.80
	15	8.26	5.88
	16	9.33	6.42
	17	10.27	6.60
	18	9.57	6.11

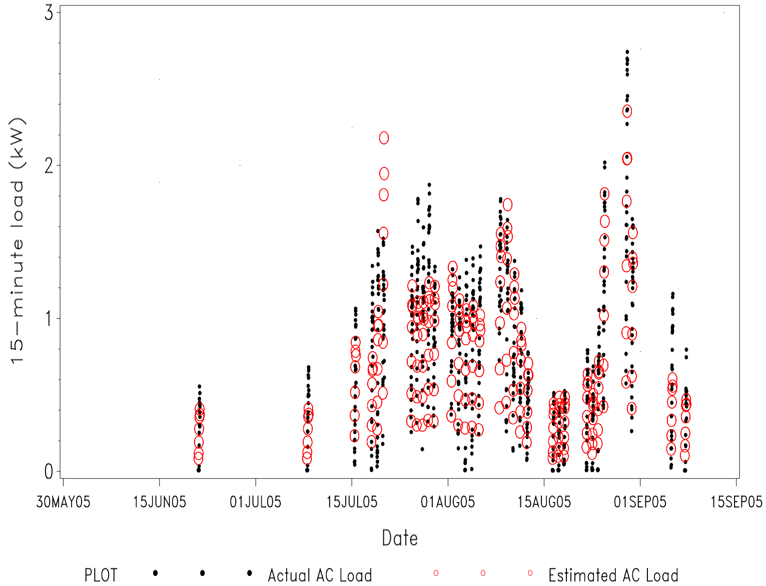
These comparisons are somewhat deceiving, because the data in the two models are different. As discussed in Chapter 2, the weather normalization model will include heating, cooling, and base parameters as determined by the choice of optimal model configuration. Heating parameters are only rarely included in the AC weather regressions. This happened primarily when a heat pump was the source of cooling. Thus, the WH models are explaining a wider range of temperature-related variation, which includes both heating and cooling. The AC models are explaining a narrower range of variation, including cooling only.

The peak hour cooling t-statistics measure the strength of the cooling degree day-related usage estimates. Unlike the AC load, not all of the whole-premise load is weather-sensitive. The increased non-weather-related variability would be expected to decrease the accuracy of the whole-premise cooling parameters, as is seen.

Figure 3–7 and Figure 3–8 show observed and modeled AC loads for the curtail groups A and B, respectively. The plotted data are limited to intervals from weekdays with an local weather station daily average temperature of 68°F or higher between the hours 11 PM and 6 PM. The data shown are for the 71 sites classed as “potential contributors”. There are 25 and 24 in the A and B curtail groups, respectively. The 21 in the dedicated comparison group and single site in the dedicated re-set group are not shown here. The black dots represent actual 15-minute load levels while the red-circles, because model estimation is done hourly, are hourly load levels. Average temperature may be above 68°F for only a subset of sites. Only days for which the majority of sites are at or above 68°F are included in the plot.

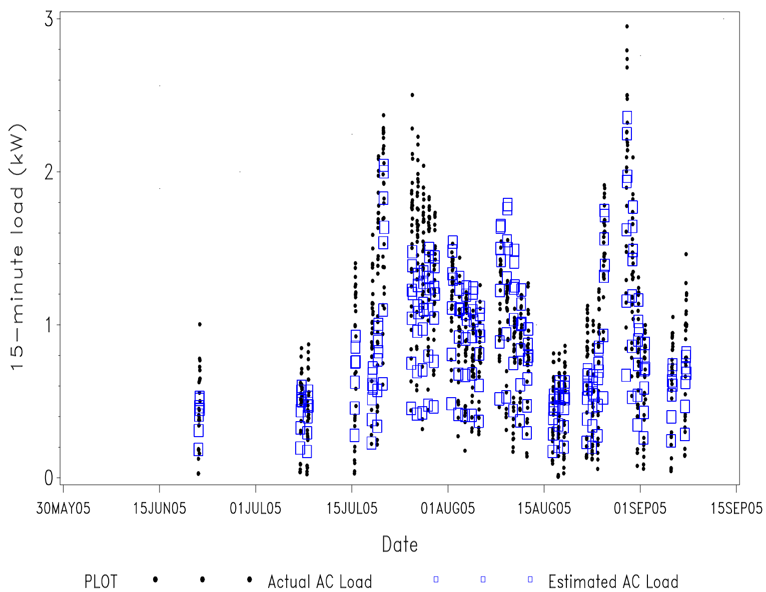
The weather normalization model does not provide particularly good estimates of the highest loads on the hottest days. The weather conditions in the San Diego area are particularly difficult to model. There is variation across the region with respect to temperature, humidity, and wind speed. Furthermore, it just is not hot enough for consistent AC use. As described in Section 2, we attempted to account for the increasing use of air conditioners after multiple days of hot weather by adding a lag term to the model. The remaining underestimation in peak conditions indicates that there are further factors driving the peak, such as humidity, that remain unaccounted for in the model. As illustrated further below, this type of systematic modeling error across customers is a reason for the use of the comparison group in the analysis. The comparison group correction appears to take care of most of the residual unaccounted for peak loads.

Figure 3-7
Group A Warm Weekday 15-minute Mean Observed (•) and Mean Estimated (◦) Loads vs. Time



Points plotted are average values up to 25 “potentially contributing” AC units in Group A.

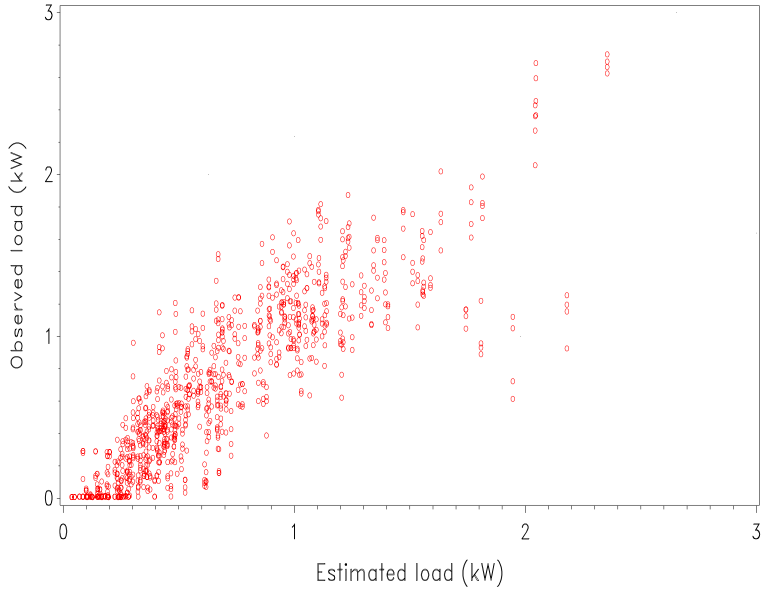
Figure 3-8
Group B Warm Weekday 15-minute Mean Observed (•) and Mean Estimated (◦) Loads vs. Time



Points plotted are average values of up to 24 “potentially contributing” AC units in Group B.

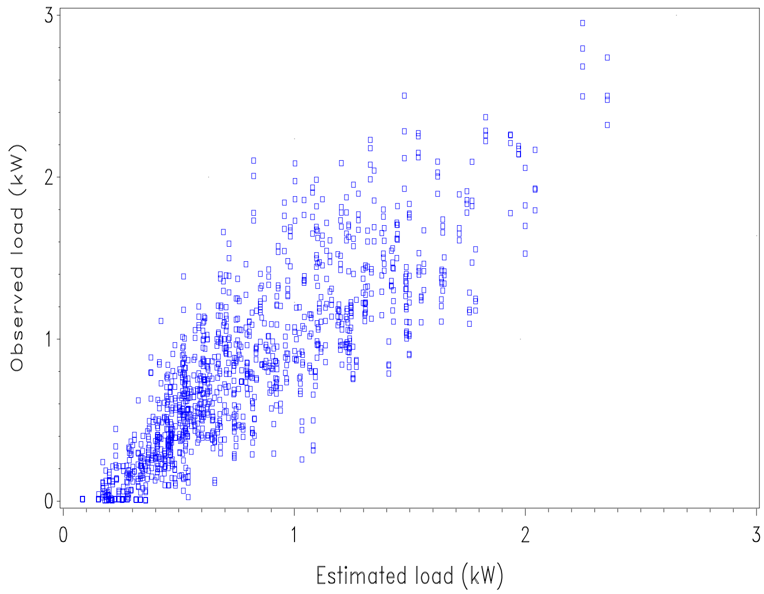
The same data shown in Figure 3–7 and Figure 3–8 are plotted in Figure 3–9 and Figure 3–10. These charts show observed versus modeled hourly mean loads. Both charts show a fairly uniform linear relationship along a 1:1 ratio of observed to estimated load. This is a good indicator of model fit. Still, there is a fair amount of estimation error given that each point is an average error over 41 and 45 AC units.

Figure 3-9
Group A Warm Weekday Observed vs. Modeled 15-minute Mean Loads



Points plotted are average values up to 28 "potentially contributing" AC units in Group A.

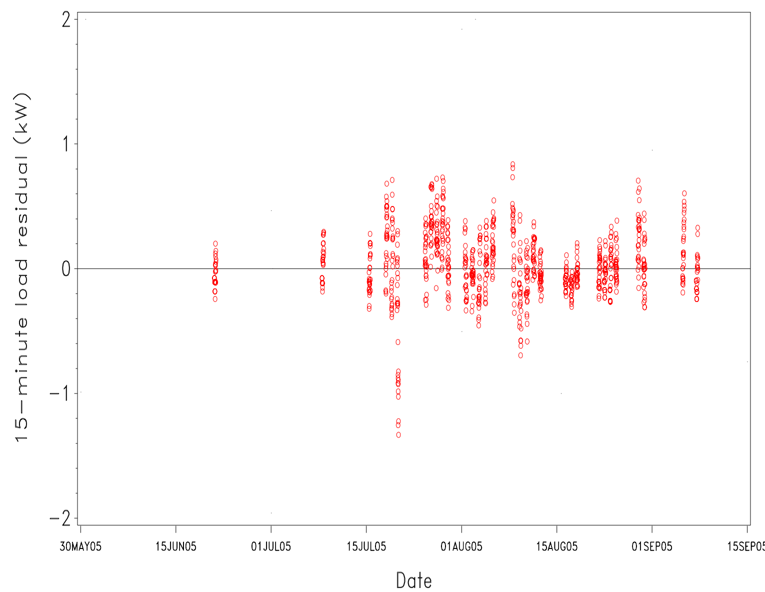
Figure 3-10
Group B Warm Weekday Observed vs. Modeled 15-minute Mean Loads



Points plotted are average values of up to 27 "potentially contributing" AC units in Group B.

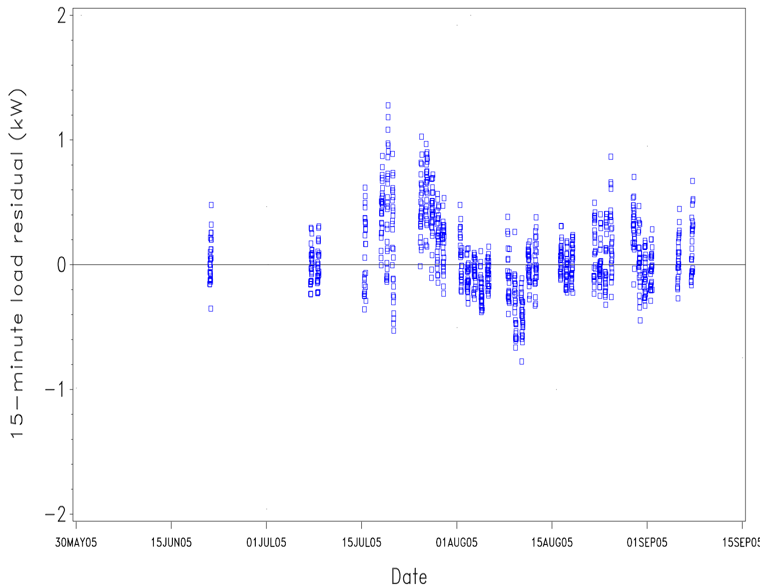
Figure 3–11 and Figure 3–12 show the mean residuals, or errors, of the model estimates of hourly mean load for warm days from May 30 to September 15 for the re-set and comparison groups, respectively. As this comparison includes only the warm days from the cooling season, we would not necessarily expect the mean of the residuals to be zero. In places, the patterns of errors over time show some dissimilarity between the two curtail groups. We expect similarity in these plots reflecting the conjecture that particular weather conditions for those days with larger errors create systematic modeling errors across sites. The comparison group approach to error correction takes advantage of this assumption. The dissimilar error patterns across curtail groups (including the dedicated comparison group, which is not shown) indicate there may be non-weather-related sources of error this year. This greater variation is also to be expected as the sample sizes shrink.

Figure 3-11
Group A Warm Weekday 15-minute Mean Load Residual vs. Time



Points plotted are average values up to 28 “potentially contributing” AC units in Group A.

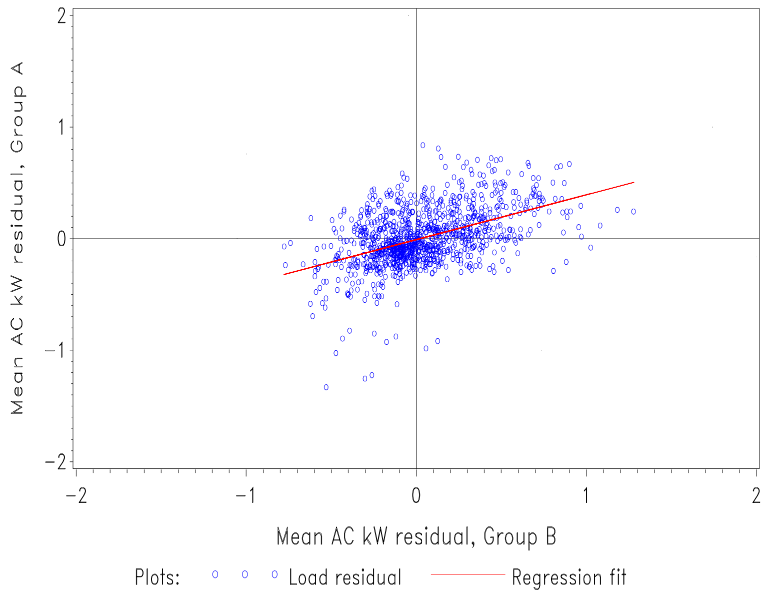
Figure 3-12
Group B Warm Weekday 15-minute Mean Load Residual vs. Time



Points plotted are average values of up to 27 “potentially contributing” AC units in Group B.

The difference of differences method requires not just that the two groups be similar in actual load, but also that the modeling error for the comparison group be a good indicator of the modeling error for the other. Figure 3–13 shows a plot of the two original curtail groups’ hourly mean residuals, one versus the other. Also shown is the regression line indicating the trend relationship.

Figure 3-13
Curtail Groups A vs. B 15-minute
AC Mean Load Residuals and Regression

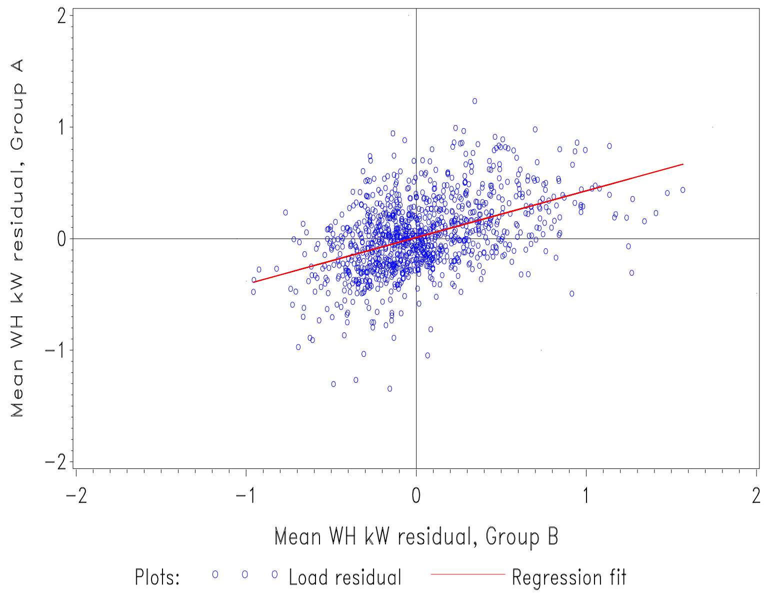


Points plotted are average values over 28 Group A and 27 Group B "potentially contributing" AC units.

As with previous years, this figure still shows a strong relationship between the curtail groups' modeling error, with the regression line passing very close to the center point (0,0). The plot also indicates that, in general, the scale of the errors is similar so that no scaling adjustment is required when using the comparison group to estimate the re-set group error. Thus, while there is some increase in the scatter compared to previous years, the comparison group approach still appears to be well-founded for the end-use AC data.

Figure 3–14 shows a similar plot for the whole-house data. The general pattern of correspondence between the two groups in the whole-house analysis is similar to that for the AC analysis. However, the range of variation is greater, as indicated before. Thus, the difference of differences method is appropriate using the whole-house data, but the accuracy of the estimates will be worse than with the AC data.

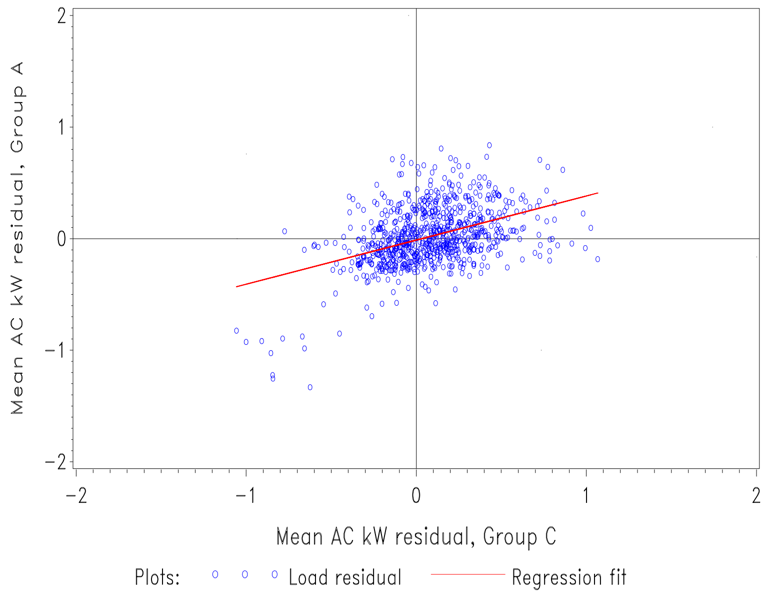
Figure 3-14
Curtail Groups A vs. B Modeling Error
Whole-House Data



Points plotted are average values over 28 Group A and 27 Group B "potentially contributing" AC units.

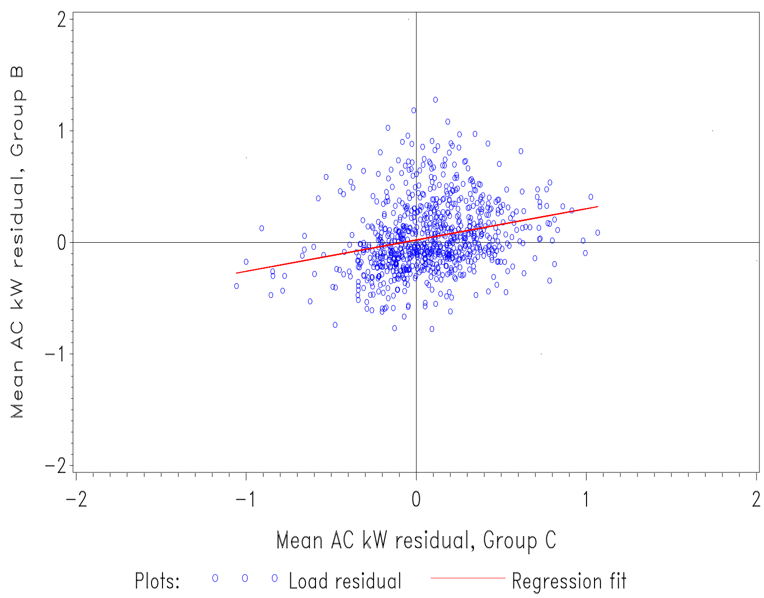
The previous plots compare curtail Groups A and B. The dedicated comparison group was not included because it joins each of the other curtail groups in turn. The plot comparing two groups' residuals is the one plot that is important to reproduce including the comparison group, or curtail Group C. We want to make sure that Group C does not undermine the relationship between curtail Groups A and B.

Figure 3-15
Curtail Groups A vs. C 15-minute
AC Mean Load Residuals and Regression



Points plotted are average values over 28 Group A and 24 Group C "potentially contributing" AC units.

Figure 3-16
Curtail Groups B vs. C 15-minute
AC Mean Load Residuals and Regression



Points plotted are average values over 27 Group B and 24 Group C "potentially contributing" AC units.

Figure 3-15 and Figure 3-16 are not as similar to each other as they were in 2004 when we first employed a dedicated comparison group. They do exhibit the same overall relationship between the two groups' modeling error and the regression lines show no systematic shift away from the origin. However, Figure 3-16 shows greater scatter than Figure 3-15. The additional scatter in the Group B versus Group C plot could indicate that the comparison group error correction would be less effective when Group B is re-set. In fact, events where Group B was re-set have lower absolute error and relative error than when Group A is re-set.

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3.5 Estimated Impacts of the Re-set Event

There were 12 re-set events during the summer of 2005. Table 3-11 gives an overview of the times, degrees re-set, and sample group for each re-set day.

Table 3-11
Re-set Event Times, Degrees Re-set, and Sample Group

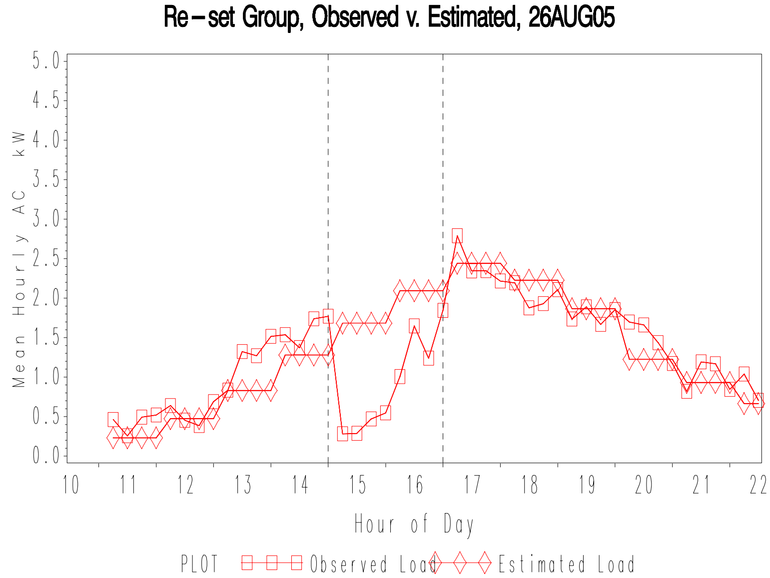
Date of Re-set	Sample Group Re-set	Start time	End time	Degrees Setback	Average Temperature
7/12/05	Both	14:00	16:00	4	70
7/13/05	B	14:00	16:00	4	73
7/14/05	A	14:00	19:00	4	75
7/21/05	B	15:10	19:10	4	80
7/22/05	A	14:00	19:00	4	80
8/26/05	A	14:00	16:00	4	80
9/28/05	B	14:00	19:00	4	73
9/29/05	A	14:00	19:00	4	78
10/6/05	B	14:00	19:00	4	75
10/7/05	A	14:00	19:00	4	71
10/13/05	B	14:00	19:00	4	67
10/14/05	A	14:00	19:00	4	77

The following section displays the methodology used in this analysis in visual plots. The re-set event that occurred on August 26th is used as an example. Similar plots for all remaining re-set events can be found in Appendix A. Corresponding plots for the whole-house analysis are in Appendix B. These plots show the impact of all potential contributors.

3.5.1 Comparison Group Approach

Group A was re-set on August 26th between 2 PM and 4 PM or hours 15 and 16. Figure 3–18 shows the re-set group's observed load compared to the estimated load.

Figure 3-17
Re-set Group Observed (—) and Estimated (--) AC Loads on Re-set Day vs. Time

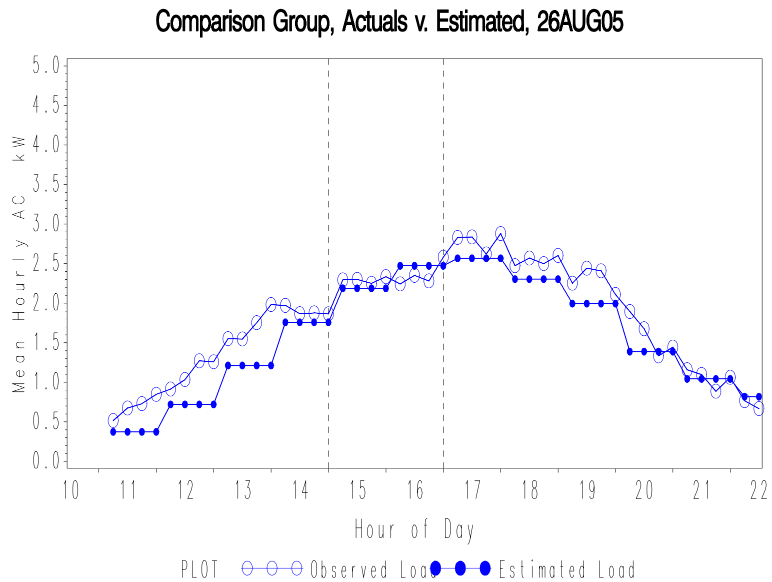


Points plotted are average values over re-set group comparison group "potentially contributing" AC units.

The re-set group's observed load diverged dramatically from the estimated load at the 4 PM start time. Maximum reductions took place immediately. During the re-set period, units will start to cycle again because the internal temperature of the thermostat has reached the new setpoint. We can see this effect throughout the event. After 4 PM, the re-set group's load jumps above the expected load as AC units cycle on full time to return to the original thermostat setpoint. The period after 4 PM, when observed load is higher than expected load, is called the "payback" period. The difference between observed and estimated load for the re-set group is the uncorrected estimate of the impact for this re-set period. Note that prior to the re-set period, observed load appears somewhat higher than estimate load.

Figure 3–18 shows the comparison group observed load compared to the estimated load for the same date. The difference between observed and estimated load for the comparison group provides the correction for the impact estimate shown in Figure 3–17.

Figure 3-18
Comparison Group Observed (—) and Estimated (--) AC Loads on Re-set Day vs. Time



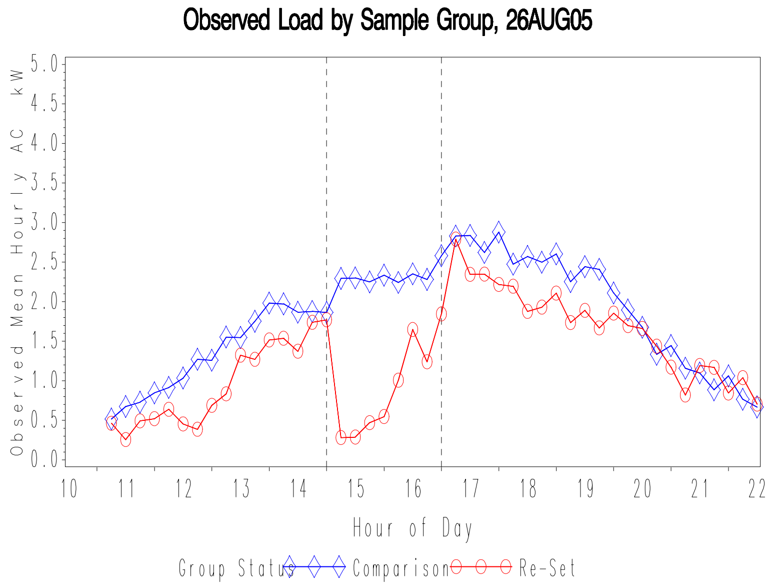
Points plotted are average values over comparison group "potentially contributing" AC units.

The comparison group gives us an idea of the effectiveness of our load modeling on that particular day. Figure 3–18 shows that the estimated load was very close to the observed load for the comparison group. For the second hour, the estimated load was slightly high. Decreasing the re-set group estimated load in the last hour in Figure 3–17 by the difference in Figure 3–18 gives an estimate of load for that hour corrected for the specific conditions of that day.

The difference of differences approach achieves just this. Subtracting observed from estimated load in Figure 3–18 provides an error correction for each interval. When this is subtracted from the uncorrected impact estimate in Figure 3–18 to get the difference of differences result, there will be a net increase or decrease to the impact estimate for that interval depending on whether the correction is negative or positive.

As indicated above we can conceive of the "difference of differences" method starting with either difference. Above we started with an uncorrected impact estimate for the re-set group derived from the estimated load and then corrected it with the error from the comparison group. Alternatively, we can start with the difference between the two sample groups and correct that impact estimate with the difference in the model-estimated loads. Figure 3–19 shows the re-set and comparison group loads on the re-set day.

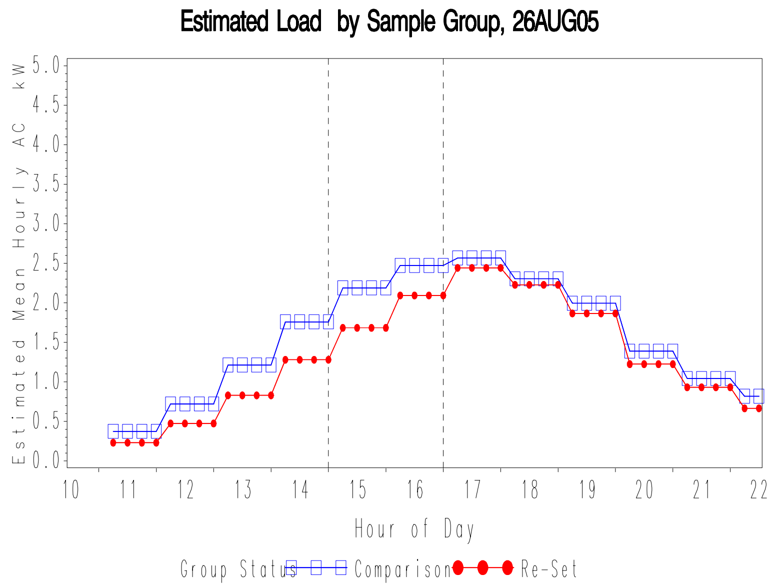
Figure 3-19
Observed 15-min Average AC Loads on Re-set Day vs. Time



Points plotted are average values over re-set and comparison group "potentially contributing" AC units.

This plot needs to be corrected by the difference of the estimated loads for the two sample groups. Figure 3–20 compares the two load estimates.

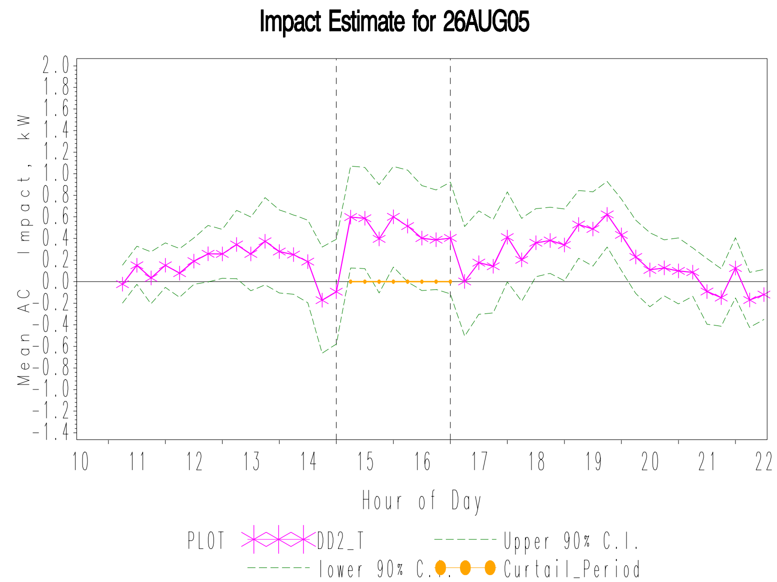
Figure 3-20
Estimated 15-min Average AC Loads on Re-set Day vs. Time



The re-set group estimated load is lower than the comparison group through the re-set period. This indicates that in Figure 3–20, all weather-related effects being equal, either the re-set group load should have been higher by this amount to put the two groups on the same terms or, alternatively, the comparison group load decreased by this amount. Either way, the original impact estimate is increased by the error correction. Viewed this way, the error correction is correcting for the tendency, noted earlier, for Group A, the re-set group on this day, to have lower load than Group B.

The corrected impact estimates, derived through the difference in differences approach, reflect the per-unit impact of all responding user units. These are units that have non-zero consumption for at least some part of the summer and received a re-set signal. It is still necessary to correct this result so that it reflects a per-unit impact for all units in the program. This result is corrected by multiplying the savings per potential contributor by the fraction these potential contributors represent of the whole. The percent of non-contributors for each day was given in Table 3–8 above. The remainder is the percent potential contributors. The final corrected impact estimates for the August 26th re-set event are displayed in Figure 3–21.

Figure 3-21
Estimated Impacts on Re-set Day vs. Time

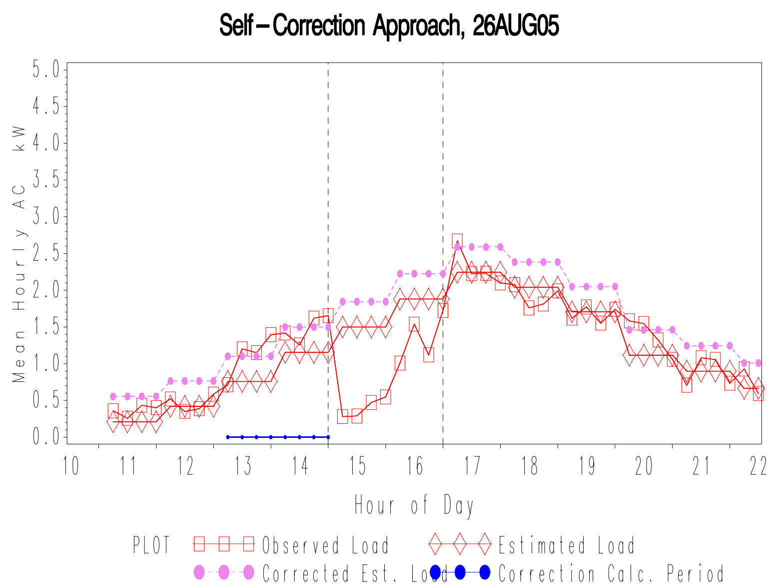


The 90 percent confidence interval lines indicate the level of statistical confidence in the estimate. If the confidence interval includes zero, then the estimate cannot be considered statistically different from zero at a 90 percent confidence level. Not every 15-minute interval in the re-set period for August 26th is statistically significant. The aggregate impact estimate does turn out to be statistically significant.

3.5.2 Savings Estimates Illustrated: Self-Corrected Approach

Figure 3–22 provides a schematic for the self-correction approach still using the July 26th event as the example. The estimated and observed loads are the same as Figure 3–17 above illustrating the re-set group observed and estimated loads. Figure 3–22 includes an indicator of the period during which the correction is calculated, the two hours prior to the start of there-set. During the prior period, the observed load is on average approximately 0.3 kW higher than the estimated load. To make the correction, the estimated load for each interval is shifted by that amount. Once corrected, the estimated load is on average the same as observed load during the correction calculation period. The corrected estimated load is then used as the baseline for comparison to the observed load during the re-set period. For the July 26th re-set day, the self-correction increased the measured impact. By comparison, Figure 3–17 shows that for July 26th, the analogous comparison group approach correction is small and makes both positive and negative corrections to the estimated load depending on the interval.

Figure 3-22
Observed (—) and Estimated (--) AC Loads
With Self-Correction



3.5.3 Air Conditioning Savings Estimates: Comparison Group Approach

The 15-minute interval results illustrated above can be presented in aggregate form for each re-set event. That is, the average kW savings across all intervals in the re-set period is determined. Table 3-12 presents the results for all 11 re-set events for which we have a comparison group.

Table 3-12
Comparison Group Approach AC Impacts and Standard Errors

Re-set Event Date	Start time	End time	Sample Group Re-set	Average Temperature	Degrees Setback	Group A AC Count	Group B AC Count	Mean Impact for Contributing AC Users	Percent Contributing AC Users	Mean Impact per AC Unit	Standard Error
7/13/2005	2:00 PM	4:00 PM	B	73	4	50	19	0.64	64%	0.41	0.14
7/14/2005	2:00 PM	7:00 PM	A	75	4	16	51	0.03	52%	0.02	0.14
7/21/2005	3:10 PM	7:10 PM	B	80	4	50	18	0.95	40%	0.38	0.14
7/22/2005	2:00 PM	7:00 PM	A	80	4	13	51	0.93	42%	0.39	0.09
8/26/2005	2:00 PM	4:00 PM	A	80	4	16	51	0.83	58%	0.49	0.25
9/28/2005	2:00 PM	7:00 PM	B	73	4	50	20	0.59	56%	0.33	0.09
9/29/2005	2:00 PM	7:00 PM	A	78	4	16	51	0.82	49%	0.40	0.11
10/6/2005	2:00 PM	7:00 PM	B	75	4	50	16	0.62	56%	0.35	0.17
10/7/2005	2:00 PM	7:00 PM	A	71	4	20	51	0.20	64%	0.13	0.11
10/13/2005	2:00 PM	7:00 PM	B	67	4	50	23	0.24	65%	0.16	0.07
10/14/2005	2:00 PM	7:00 PM	A	77	4	17	51	0.41	61%	0.25	0.09

As indicated by the confidence intervals in Table 3-13, the average kW impact estimate is statistically significant at the 90 percent level on 9 of the 11 re-set days. The non-significant results are highlighted in blue.

The average estimated impact across the 11 days is 0.30 kW. As in 2004, the savings associated with Group B are on average higher than those for curtail Group A. The difference in 2005 is smaller than in 2004 and, in fact, neither year's difference is statistically significant.

Table 3-13 provides the impact results with confidence intervals for both a single unit and for 5,000 units, the target size of the Smart Thermostat Program.

Table 3-13
Comparison Group Approach
AC Impacts with Confidence Intervals, Per Unit and for 5,000 Units

	Mean kW Per Unit				kW for 5000 Units		
Date	Impact	Standard Error	90% Confidence Lower Bound	90% Confidence Upper Bound	Impact	90% Confidence Lower Bound	90% Confidence Upper Bound
7/13/05	0.41	0.14	0.17	0.65	2,063	858	3,267
7/14/05	0.02	0.14	-0.22	0.25	89	-1,092	1,269
7/21/05	0.38	0.14	0.15	0.62	1,914	747	3,081
7/22/05	0.39	0.09	0.24	0.53	1,926	1,179	2,673
8/26/05	0.49	0.25	0.06	0.91	2,433	300	4,566
9/28/05	0.33	0.09	0.18	0.47	1,632	906	2,359
9/29/05	0.40	0.11	0.22	0.58	1,999	1,106	2,891
10/6/05	0.35	0.17	0.07	0.63	1,729	330	3,127
10/7/05	0.13	0.11	-0.06	0.32	640	-306	1,585
10/13/05	0.16	0.07	0.04	0.28	777	177	1,376
10/14/05	0.25	0.09	0.09	0.41	1,245	445	2,044

3.5.4 Whole-premises Savings Estimates: Comparison Group Approach

The energy savings based on the whole-premises metering data are presented in Table 3-14.

Table 3-14
Comparison Group Approach Whole-premises Impacts and Standard Errors

Re-set Event Date	Start time	End time	Sample Group Re-set	Average Temperature	Degrees Setback	Group A AC Count	Group B AC Count	Mean Impact for Contributing AC Users	Percent Contributing AC Users	Mean Impact per AC Unit	Standard Error
7/13/2005	2:00 PM	4:00 PM	B	73	4	51	19	0.80	64%	0.51	0.18
7/14/2005	2:00 PM	7:00 PM	A	75	4	17	51	0.07	51%	0.04	0.16
7/21/2005	3:10 PM	7:10 PM	B	80	4	51	18	0.90	40%	0.36	0.14
7/22/2005	2:00 PM	7:00 PM	A	80	4	14	51	0.99	41%	0.41	0.11
8/26/2005	2:00 PM	4:00 PM	A	80	4	17	51	1.04	58%	0.60	0.27
9/28/2005	2:00 PM	7:00 PM	B	73	4	51	20	0.77	55%	0.42	0.10
9/29/2005	2:00 PM	7:00 PM	A	78	4	17	51	0.71	48%	0.34	0.11
10/6/2005	2:00 PM	7:00 PM	B	75	4	51	16	0.80	55%	0.44	0.18
10/7/2005	2:00 PM	7:00 PM	A	71	4	21	51	0.11	63%	0.07	0.14
10/13/2005	2:00 PM	7:00 PM	B	67	4	51	23	0.30	64%	0.19	0.10
10/14/2005	2:00 PM	7:00 PM	A	77	4	17	51	0.40	61%	0.24	0.13

The whole-premises data impact results are consistent with the AC data results. However, unlike in previous years, whole house impacts for individual days are not consistently higher than the end use impact estimates. In four instances the AC impact estimate is greater than the whole premises results. On average, though, the whole-premises results do reflect the expected increased savings related to decreased use of the interior air distribution fan that is not included in the air conditioning metering data. Despite the four days when AC savings is greater, on average, the savings from the whole-premises data is 10 percent greater than the end-use data results. This is twice the marginal increase for the whole-premises results compared to 2004.

In addition, for 2005 the whole-premises results are more comparable to the AC results with regards to significance than was the case in previous years. Despite having bigger relative average standard error than the AC results, 9 of the 11 re-set day results are statistically different from zero.

Table 3-15 provides the whole-premises impact results with confidence intervals for both a single premise and for 5,000 sites.

Table 3-15
Comparison Group Approach
Whole-premises Impacts with Confidence Intervals, Per Unit and for 5,000 Sites

Date	Mean kW Per Unit				kW for 5000 Units		
	Impact	Standard Error	90% Confidence Lower Bound	90% Confidence Upper Bound	Impact	90% Confidence Lower Bound	90% Confidence Upper Bound
7/13/05	0.51	0.18	0.21	0.81	2,551	1,030	4,072
7/14/05	0.04	0.16	-0.23	0.31	184	-1,174	1,542
7/21/05	0.36	0.14	0.11	0.60	1,793	572	3,013
7/22/05	0.41	0.11	0.23	0.59	2,037	1,143	2,930
8/26/05	0.60	0.27	0.15	1.05	2,995	737	5,253
9/28/05	0.42	0.10	0.25	0.59	2,107	1,255	2,959
9/29/05	0.34	0.11	0.15	0.54	1,704	732	2,677
10/6/05	0.44	0.18	0.13	0.75	2,214	654	3,774
10/7/05	0.07	0.14	-0.16	0.30	346	-824	1,517
10/13/05	0.19	0.10	0.02	0.37	953	75	1,831
10/14/05	0.24	0.13	0.03	0.46	1,213	148	2,278

3.5.5 Correction Approaches Compared

There were two good reasons for developing the self-corrected approach. The immediate motivation for this analysis was to estimate impacts for the two complete re-set event days when all devices were re-set so that the usual comparison group did not exist. A larger motivation was to provide a potential alternative to the comparison group approach. The motivations are related by the matter of sample size.

The self-corrected approach provides results using a single sample, in the case of the two complete re-set events, the combined curtail Groups A and B. The comparison group approach always has the two samples. The self-corrected approach enjoys the advantage of the larger meter population due to the combined curtail groups. The comparison group approach combines the variance of the two sample groups. All else being equal, the additional population included in the self-corrected approach variance calculation will result in a lower standard error.

We produce alternative results for the 11 “standard” event days where a comparison group exists. This allows for a comparison across the two approaches. We are limited to the sample sizes defined by the curtail groups. The comparison group approach uses the full available sample including the dedicated comparison group. The impact variance is, thus, a combination of the re-set and comparison groups’ estimated variances. The self-corrected approach impact variance is the re-set group’s variance alone. The size of the re-set group alone is never more than a third of the whole population used by the comparison group approach.

If we were starting from scratch, the self-corrected results would come at a third to a quarter the metering cost, or conversely, could be improved substantially with the increased sample size.

Looking ahead for the current program, with continuing attrition of the metering sample, the self-correction approach has the potential to allow us to maintain re-set sample sizes without installing additional meters.

Table 3-16 provides the 2005 results using the self-corrected approach to estimating impacts. It is immediately clear that the self-corrected approach provides as many statistically significant results as the comparison group approach.

Table 3-16
Self-Corrected Approach
AC Impacts with Confidence Intervals,

	Mean kW Per Unit			
Date	Impact	Standard Error	90% Confidence Lower Bound	90% Confidence Upper Bound
7/13/05	0.39	0.16	0.12	0.66
7/14/05	-0.20	0.13	-0.43	0.04
7/21/05	0.75	0.17	0.44	1.05
7/22/05	0.38	0.12	0.17	0.59
8/26/05	0.45	0.21	0.08	0.82
9/28/05	0.08	0.03	0.02	0.14
9/29/05	0.28	0.08	0.14	0.41
10/6/05	0.22	0.06	0.12	0.32
10/7/05	0.11	0.04	0.03	0.19
10/13/05	0.06	0.05	-0.02	0.14
10/14/05	0.26	0.09	0.10	0.42

Table 3-17 compares the AC results for the self-correction approach with the AC results for the comparison group reported above. The results for any give day are substantially different across the two methods. In fact, only 4 of the 11 results are within 20 percent. Overall, however, the average difference is only 0.05 kW, with the self-correction approach showing a 15 percent reduction relative to the comparison group approach. This difference is not statistically different. The average difference falls to only 0,03 percent if only statistical significant results are include in the average.

Table 3-17
Comparison of Impact Estimation Approaches, 2005 Program

date	Group Re-set	Impact, By Approach				Standard Error, By Approach			
		Comparison Group (X)	Self-Correction (Y)	Difference (X=Y)	% Difference (X-Y)/avg(X,Y)	Comparison Group (X)	Self-Correction (Y)	Difference (X=Y)	% Difference (X-Y)/avg(X,Y)
7/13/2005	B	0.41	0.39	0.02	5%	0.142	0.155	-0.013	-9%
7/14/2005	A	0.02	-0.20	0.22	-239%	0.139	0.135	0.005	3%
7/21/2005	B	0.38	0.75	-0.36	-64%	0.138	0.174	-0.036	-23%
7/22/2005	A	0.39	0.38	0.00	0%	0.088	0.117	-0.029	-28%
8/26/2005	A	0.49	0.45	0.04	8%	0.252	0.213	0.039	17%
9/28/2005	B	0.33	0.08	0.25	121%	0.086	0.033	0.053	89%
9/29/2005	A	0.40	0.28	0.12	37%	0.105	0.078	0.028	30%
10/6/2005	B	0.35	0.22	0.12	43%	0.165	0.057	0.108	97%
10/7/2005	A	0.13	0.11	0.02	14%	0.112	0.045	0.067	86%
10/13/2005	B	0.16	0.06	0.10	89%	0.071	0.049	0.022	38%
10/14/2005	A	0.25	0.26	-0.01	-5%	0.094	0.093	0.001	1%
Average		0.30	0.25	0.05	15%	0.13	0.10	0.022	18%

One reason the self-correction tends to give smaller impacts may be the tendency noted earlier for the model to under-predict load on very hot days. This tendency will be greater during hours when the cooling load is greater. With the comparison group method, the underestimate in the comparison group provides an adjustment for each hour. With the self-correction method, we rely on hours prior to the re-set period, which could result in incomplete adjustment for the model underestimate. To the extent this explanation accounts for the differences between the two methods, the comparison group approach would be favored.

The standard errors are also compared in Table 3-17. For 8 of 11 events, the self-correction approach standard error is smaller than the comparison group approach standard error. Despite utilizing substantially less sample, the self-correction approach provides, on average, 18 percent smaller standard errors.

A check of the 2004 results finds a similar pattern. The self-corrected approach impact estimates are smaller by 14 percent. The standard error is also smaller by 3 percent. One additional event was deemed not statistically different from zero compared to the comparison group approach.

While this is not a perfect comparison, the results seem to indicate that the self-corrected approach is worthy of consideration. Using less than a third of the meters (in 2005) a similar level of error is maintained. The impact estimates are different, but it is not clear which is more correct. All but one of the separate differences are not statistically different.

3.5.6 Savings Estimates for May 3, 2004, and July 12, 2005

The primary motivation for development of the self-correction approach was to provide a methodology for evaluating re-set events where no comparison group existed. Table 3-18 shows the self-corrected approach results for the two days where the full meter population was re-set.

Table 3-18
Full Population Re-set Event Impact Results, Self-Corrected Approach

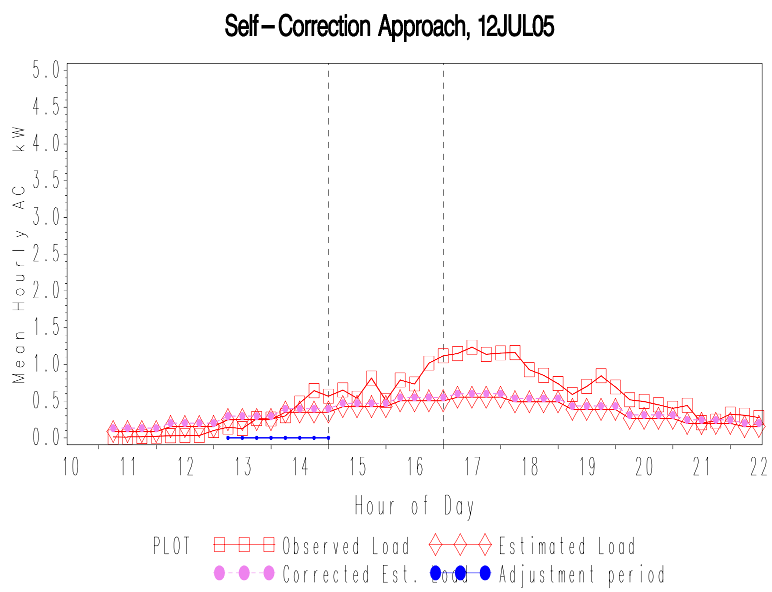
Re-set Event Date	Start time	End time	Average Temperature	Degrees Setback	Group AC Count	Mean Impact for Contributing AC Users	Percent Contributing AC Users	Mean Impact per AC Unit	Standard Error
5/3/2004	4:00 PM	7:00 PM	82	4	52	0.45	50%	0.22	0.10
7/12/2005	2:00 PM	4:00 PM	70	4	42	-0.24	69%	-0.16	0.06

Despite being very early in the cooling season, May 3, 2004, generated positive, statistically significant savings of 0.22 kW. To the contrary, the event on July 12, 2005, generated negative savings. The 2004 event was the hottest event day of the 2004 cooling season. It probably generated smaller savings than expected because it came so early in the season that many units were still turned off. The override rate was also high for those that did have their AC units turned on.

For the 2005 event, the average temperature was relatively low at 70°F. Little savings would be expected on such a day. Though it was July, there had been very little cooling weather at that point. Any AC units not yet turned on for the cooling season would further depress potential savings. Finally, the estimated load shape was not a good match for the day.

Figure 3–23 shows a plot of the self-correction approach for July 12, 2004. The plot indicates that, in fact, usage, even with the re-set, was higher than the model predicted for that day. The correction was negligible. In this case, the model was approximately correct during the correction period but appears to underestimate load during the re-set event. There is some evidence of a re-set effect in the observed usage.

Figure 3-23
Observed (—) and Estimated (--) AC Loads July 12, 2005 with Self-Correction



The figure provides an argument for the comparison group approach. One would assume the comparison group, on this day, would have been similarly underestimated. The comparison group failure, then, would have perhaps avoided the negative estimate of impact.

3.6 IMPACT PROJECTIONS

3.6.1 Modeling the Override Rate

To incorporate override rate into the impact projections, we need an estimate of override across all potential cooling temperatures. For the 2003 and 2004 impact analyses, we modeled the override rate with a log-odds model applied to the event day override percents. This approach provided an estimate across all temperatures though only based on 12 or 24 data points.

A survival analysis approach was proposed for this the 2005 impact analysis in part because it makes use of the thousands of individual participant data points we have in the event data. The goal is a more robust model. We model 2005 data alone as the more extensive program-wide data is not available for the previous years.

As described in Section 2, the data used in the survival model are all customer-event combinations of time to over-ride, or to the end of the re-set period without over-ride. Observations for the same customer on different days are not independent. The dependency affects the result of the recurring events survival model in two ways: Standard errors can be incorrect and parameter estimates can be forced toward zero. The standard error concerns are easily addressed but are not essential to our analysis. Model statistics indicate that there is only minimal downward parameter bias in the model estimates. Most importantly, a visual check of model projections relative to actual event survival curves indicates the model is impressively accurate.

Figure 3-24 below shows the predicted override rate from the survival analysis results for events of five hours duration. This is compared to the log-odds results applied to 2005 aggregate percentages and the observed percents for the event days with events of that duration. In the range of likely temperature, the two curves are similar.

Figure 3-24
Predicted and Observed Override Rates vs. Outdoor Temperature, 5-Hour Event Duration: Old Log-Odds vs. New Proportional Hazards Results

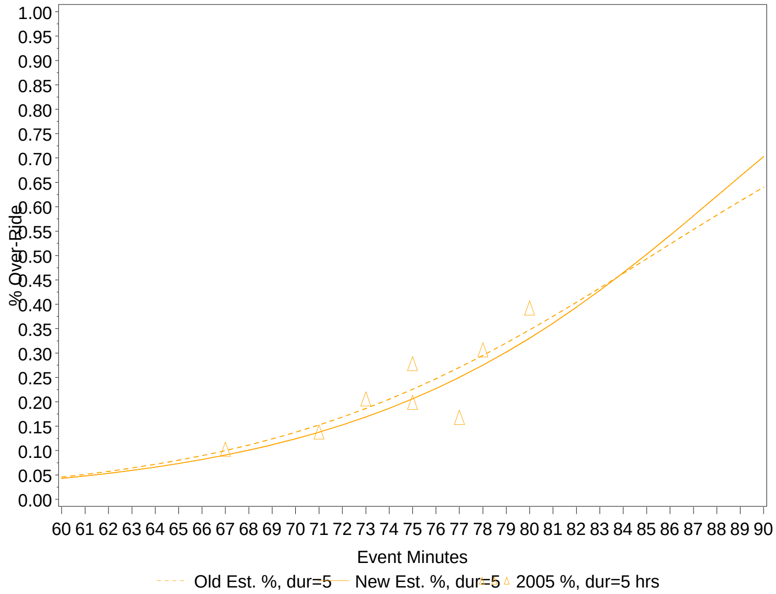
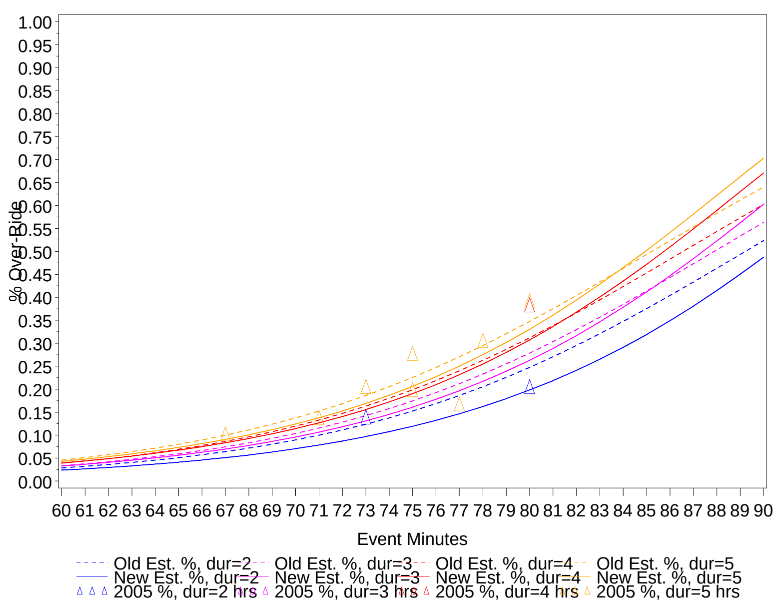


Figure 3-25 shows the same plot as Figure 3-24 with the four different event durations included. There were only three events of durations other than five hours. The survival analysis approach models the time when participants override regardless of the duration of the event. There is only one survival curve which can be observed at any point in time. Unlike the log-odds model, the survival analysis model can estimate the percent override at any point in time.

Figure 3-25
Predicted and Observed Override Rates vs. Outdoor Temperature, Multiple Event Durations: Old Log-Odds vs. New Proportional Hazards Results



3.6.2 Projected Impacts by Temperature and Re-set Amount

Projected impacts at various outside temperatures and re-set amounts were estimated from the same load models developed in the analysis of the specific re-set event, as described in Section 2. For each unit with good data and non-zero summer use, the unit's load model was used to calculate the load for each hour of the day at a given daily average temperature. The same model was used also to calculate the hourly loads assuming an increase in the thermostat setpoint. This increase was represented in the model as an increase in the unit's cooling reference temperature. Because a single cooling reference setpoint was estimated for both the day-of and lag coefficients, the setpoint is increased for both. The difference in the model's estimate of load with and without the setpoint change was the estimated savings at that outside temperature and re-set amount for each hour.

The addition of the lagged temperature variable added a complication to this procedure since 2004. For any day-of average temperature, the lag temperature representing the three previous days will vary depending on whether we are projecting savings for the first day of a hot spell or the fourth. For the 12 re-set events in 2005, the median lag temperature was 3.8ºF lower than the daily average temperature for that day. The first and third quartile differences are 5.6ºF lower and 2.0ºF lower, respectively. This is a substantially greater lag differential than was experienced in 2003 and 2004. The median lag temperature over those 24 re-set events was only 0.8ºF lower than average temperature of the re-set day. The 2005 events almost all occurred at the peak of a heat wave, maximizing the lag differential.

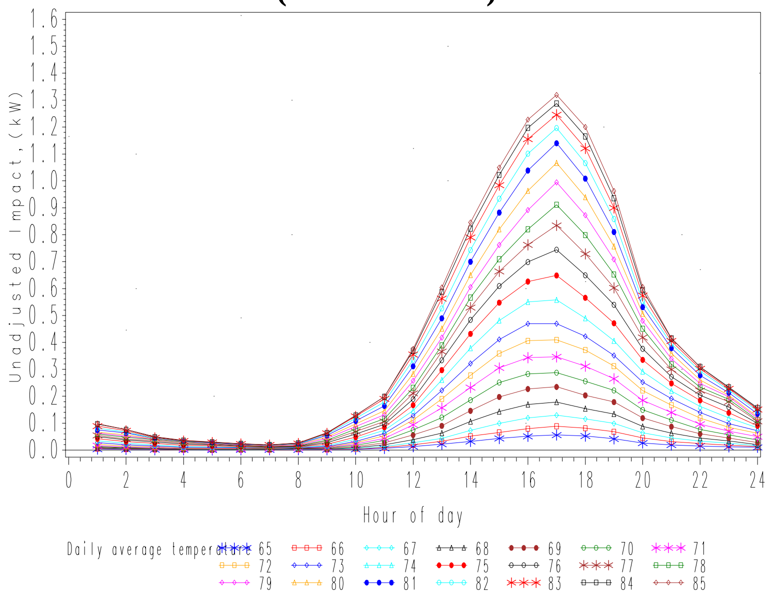
The bulk of the projections illustrated here are based on the median scenario, a lag temperature that was 3.8ºF lower than the day-of average temperature. We also provide an indication of the range of outcomes given the range of possible lag temperatures. The projections tables in Appendix D are similarly arranged. Projections for all hours and scenarios are provided using the median lag temperature. In addition, for one hour, the range of outcomes is provided. This could allow a program manager to fine tune projections to reflect weather for the previous days.

Once individual site savings estimates were produced, they were averaged across all units in the sample for which the model could be estimated. For this projection analysis, actual event participation was not relevant. The unadjusted savings estimates apply to the universe of potential contributors. Adjusting these results by the fraction of potential contributors provides estimates of savings given expected rates of zero use, non-response, and override.

The results are plotted by time of day in Figure 3–26 for a 4°F re-set and various average daily outside temperatures. These are the impacts per potential contributor without adjustment for signal failure, overrides, or zero summer use. That is, Figure 3–26 shows the unadjusted projected impacts. Projected impacts, without adjustment for non-contributors, are tabulated in Appendix C for each combination of re-set amount and average outside temperature.

The figure shows that unadjusted savings are low at low outside temperatures, where air conditioning use is low, and higher at higher outside temperatures. Savings are also low in the early morning and overnight. Savings per unit are greater at higher outside temperatures because a larger fraction of AC units are on. At lower temperatures, many of the units have zero estimated load and zero savings.

Figure 3-26
Unadjusted Projected Impacts by Hour, Average per AC Unit
(For 4°F Re-set)



For outside temperatures above 85°F, there is no additional increase in the unadjusted projected savings. This leveling off occurs once the outside temperature exceeds the point where all the units are projected to be on, based on the individual load model fits. The load models assume a linear relationship between load and outside temperature above each unit's reference temperature. Thus, a 4°F shift in reference temperature has the same effect on load for all outside temperatures above this reference point.

Figure 3-27 and Figure3-28 show the projected impacts adjusted by an estimate of the potential contributors percentage from the 12 re-set events during the summer of 2005. The first plot shows the adjusted impacts on the same scale as the unadjusted impacts displayed in Figure 3-26. The second plot expands the scale so that the patterns can be seen more easily.

For the adjusted projected impacts shown in Figure 3-27 and Figure3-28, average signal failure and zero use percentages are applied with an estimated override percent. Override is estimated as a function of temperature using the survival analysis approach as discussed in Section 3.6.1. Projected impacts, adjusted for non-contributors, are tabulated in Appendix D for each combination of re-set amount and average outside temperature.

Figure 3-27
Adjusted Projected Impacts by Hour, Average per AC Unit
(For 4°F Re-set, 4-Hour duration)

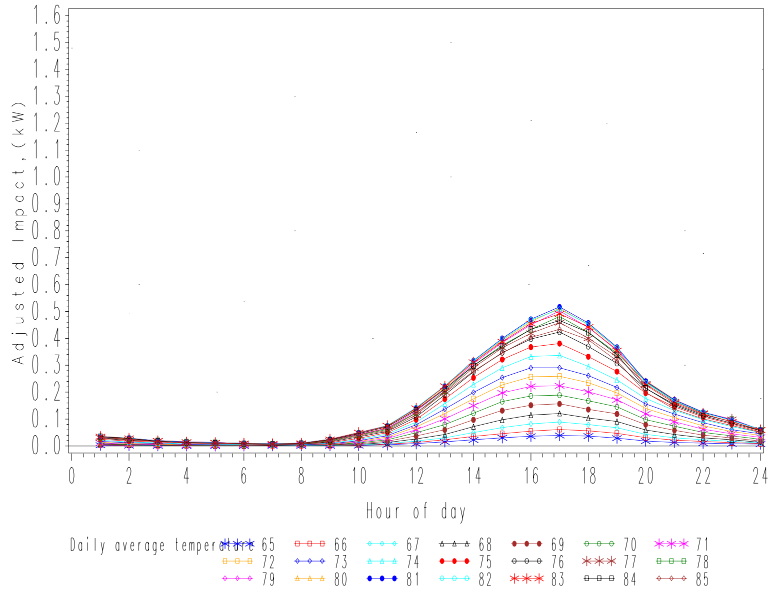
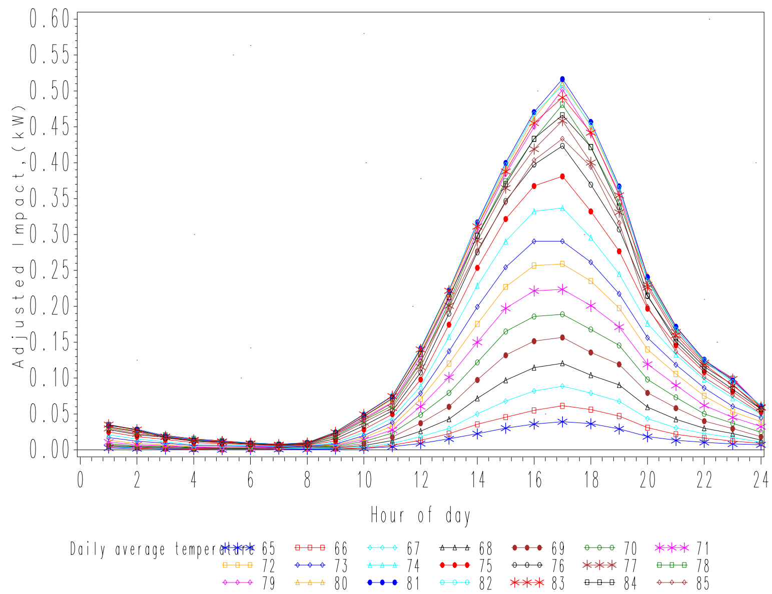


Figure 3-28
Adjusted Projected Impacts by Hour, Average per AC Unit, Full Scale
(For 4°F Re-set, 4-Hour duration)



In Figure 3–27 and Figure 3–28 the adjusted projected savings decline above 81°F. Savings is a function of temperature while override rates are a function of both temperature and re-set duration. Both increase with increasing temperature, but at different rates. These figures indicate that the effect of the increase in override percent is greater above 81°F than the increase in savings.

Figure 3–29 below illustrates the relationship between savings and temperature for the peak hours. For the 2005 analysis, adjusted savings increases steadily up to 81°F (for hours 15 through 19) at which point the override rate takes over and the savings decrease.

Figure 3-29
Adjusted Projected Impacts by Temperature, Average per AC Unit
(For 4°F Re-set, 4-Hour duration)

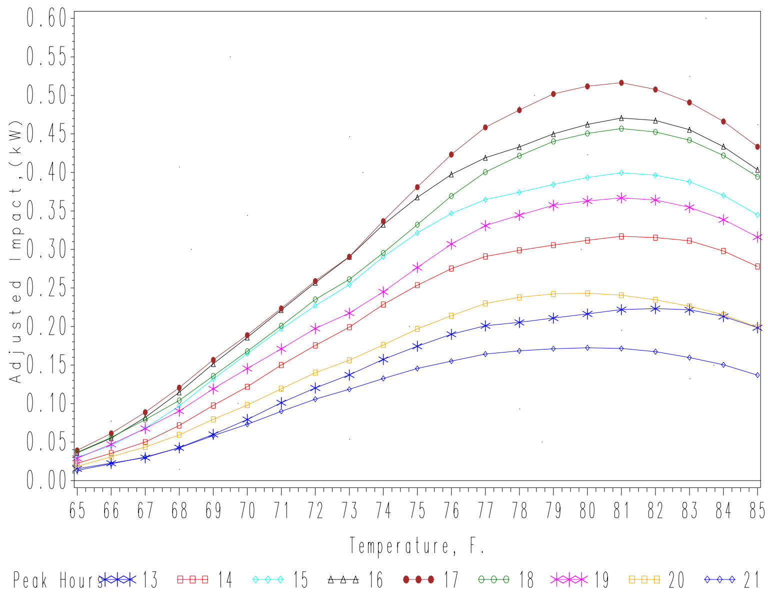


Figure 3-30 shows the range of hour 17 savings depending on the lag-day temperature effect. The middle line is the same as hour 17 in Figure 3-29. This reflects the median relationship between day-of and lag-day temperatures. The other two lines reflect the first and third quartile of the same relationship. The warmer the previous day, the greater the savings.

Figure 3-30
Hour 17 Adjusted Projected Impacts by Temperature, Average per AC Unit with High and Low Lag Temperatures (For 4°F Re-set, 4-Hour duration)

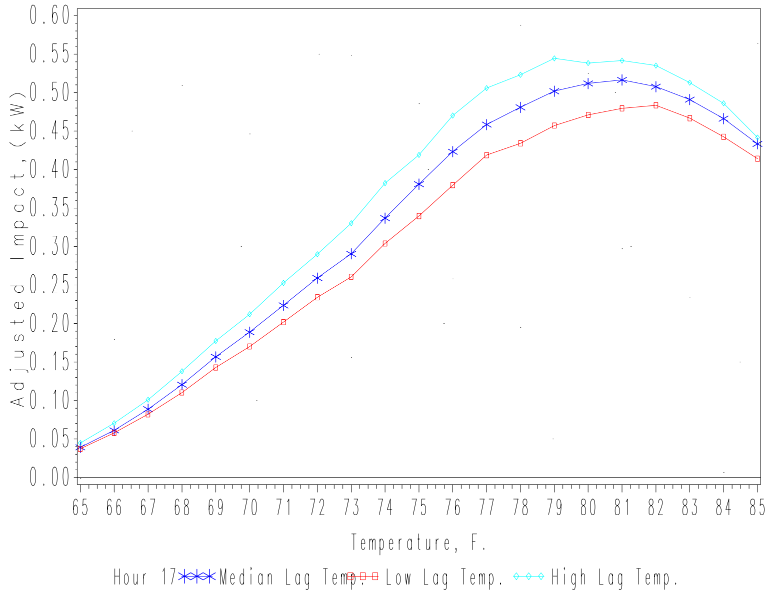
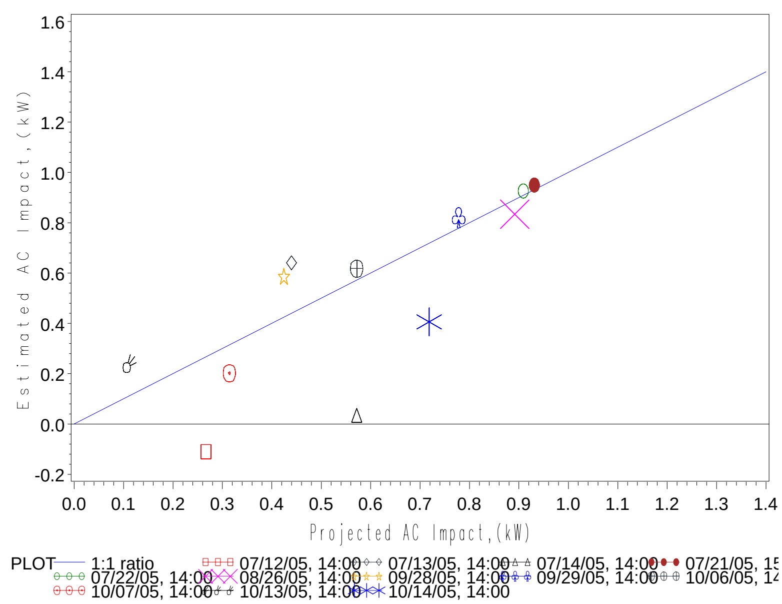


Figure 3–31 below compares the unadjusted projected savings for each re-set event with the unadjusted mean AC impact estimated earlier using the comparison group approach. Projected impacts for each re-set are calculated using the appropriate temperature, event duration, and re-set amount. We focus on the unadjusted projections and results because they both face the same program population-based adjustment factors.

Figure 3-31
Unadjusted Estimated vs. Projected AC Impact
Average Impact for Each Event



The diagonal blue line in the figure represents a 1:1 ratio. For the 2005 analysis, the plot indicates that our projections are quite close for the majority of events and generally improve as the magnitude of the savings increases. Given the various sources of potential error in the savings estimation process and the projection process, these results are quite encouraging.

One potential reason for the disparity between the particular-day estimates and the corresponding projections for the general conditions is worth noting: How the particular day is mapped to the general condition. The general condition is defined by an ambient temperature and re-set amount. However, the sites in the study are modeled using seven different weather stations. For purposes of this comparison, we used the average temperature across all the non-zero users in the metering sample to define the general condition. Effectively then, the projection assigns the same temperature to all sites, whereas the particular-day estimates used the local temperature for each. This difference contributes to the variation seen in Figure 3–31.

4 CONCLUSIONS

In the summer of 2005, the Smart Thermostat Program invoked 12 re-set events. These events allow us to estimate the impacts of the program for the actual summer as used as well as projected impacts under various conditions.

The analysis this year offers several methodological improvements over previous years.

- Unlike the previous two years, all of the 2005 re-set events included the full program population. Eleven of the 12 events were "standard" re-set events from an evaluation perspective. That is, part of the metered group, the comparison group for that day, was not re-set. For these 11 events, we were able to pursue the original proposed methodology to its full extent. Potential contributor percentages are based on actual program population percentages.
- In addition, we developed an alternative methodology that works without a comparison group. This methodology, the self-correction approach, was applied to all 12 events. This method provides an alternative estimation approach for situations when no comparison group is available or for future evaluations as the available metering sample shrinks from ongoing attrition.
- Finally, we developed and applied a new approach to modeling the probability of re-set override by program participants.

Following are some of the key findings from the 2005 study with comparisons to the earlier results.

4.1 WHAT FRACTION CONTRIBUTES TO SAVINGS

4.1.1 Non-Responding Units

- The non-response rate (the fraction of units in the program that do not receive re-set signals) across the 12 events for 2005 averaged 8 percent. Fully 6 percent of program participants were non-responders for every re-set event for which they were re-set.
- Non-response appears to be worse for the more recent additions to the program. Of the 263 meters re-set for only the four October dates, 19 percent never received the signal.
- The non-response rate among the meter sample averaged 11 percent. Essentially all non-responders in the meter sample were non-responders for every re-set. In the absence of full program information, this is the non-response estimate that would have been used. Since the full program information is available for 2005, we recommend the average of this complete information (8 percent, above) as the best estimate for projections or future cases where the actual response rate is not known.

4.1.2 Over-Ride Rates

- The override rate across the 12 2005 events averaged 22 percent. It ranged from a low of 9 percent to a high of 39 percent. Forty percent of the program population never overrode the re-set during an event. A negligible percent overrode every re-set event.

4.1.3 Zero Users

- The percentage of AC units never used during summer weekdays was 17 percent for the 2005 cooling season. This percent is estimated from the meter sample. It is the same percent as in the summer of 2004.
- AC non-use cannot be tracked in the program data. The non-use estimate cannot be checked. This estimate may be inflated if AC meters at the residences are found to be giving false zeros. At this time each false zero meter increases the percent AC non-use by approximately 1 percent. This issue is under review by SDG&E personnel.

4.1.4 Overall Percent Contributing to Savings

The average combined effect of non-response, over-ride, and non-use was 44 percent of participating units did not contribute to savings in 2005. This level falls in between the non-contributor percentages from 2003 and 2004, 42 percent and 48 percent, respectively.

4.1.5 Effect of Population on Standard Errors

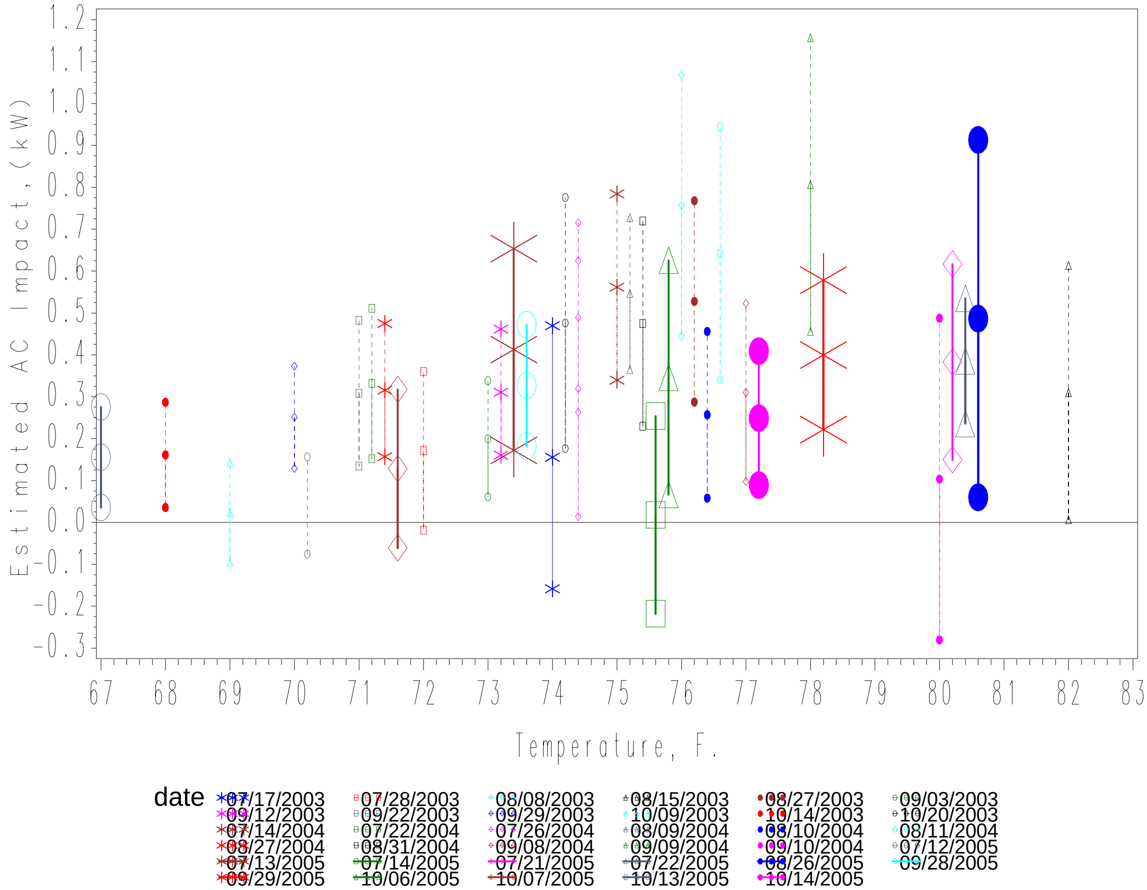
This is the first year it has been possible to quantify the advantage of using full population program data to estimate non-response and override rates. Using the 2005 full population data decreases the standard error of the non-contributors percentage by approximately 50 percent. The standard error of the impact estimate is reduced by 5 percent, on average, over the 12 days.

4.2 Savings for the Re-set Days

Impact estimates for 2005 and previous years are summarized in Figure 4-1. The midpoint of each bar represents the impact estimate while the range of each bar indicates the 90 percent confidence intervals. The 11 "standard" individual re-set events for 2005 are displayed with larger symbols and a bolder unbroken line.

The results are organized by average temperature. Where multiple event days have the same temperature, the results are offset slightly so they can be seen.

Figure 4-1
Impact Estimates by Date with Error Bars
2003 through 2005



The 2005 savings per AC unit enrolled in the program average 0.30 kW. For 9 of the 11 standard re-set events the impacts were statistically different from zero.

Table 4-1 shows the average results for 2005 and the average results for the two previous years. The results can be compared despite some differences in methodology for the 2005 analysis. The 2005 results are almost identical to the 2003 results. Both 2003 and 2005 are very similar and are substantially below 2004.

Table 4-1
Estimated kW Impacts

	Impact (kW)	Standard Error	90% Confidence Lower Bound	90% Confidence Upper Bound
Average of All Events				
per unit	0.35	0.14	0.12	0.57
5000 units	1,728	684	602	2,853
Average of 2005 Events				
per unit	0.30	0.13	0.08	0.52
5000 units	1,495	670	394	2,597
Average of 2004 Events				
per unit	0.43	0.16	0.17	0.69
5000 units	2148	791	847	3,449
Average of 2003 Events				
per unit	0.30	0.14	0.08	0.53
5000 units	1,520	684	396	2,645

These results are only partially consistent with the weather experienced on re-set days across the three years. 2004 had the hottest set of event days of the three years and has the highest impact. The event days in 2005 were hotter than 2003 across all the indices, but there was no increase in average savings.

4.2.1 Alternative Methodology Compared

The results reported above were all produced with the original methodology with some minor variations in 2005. We also report 2005 results produced with the alternative methodology, the self-correction approach. This approach has the advantage of not requiring a comparison group. The self-corrected approach savings per AC unit average 0.25 kW across the 11 “standard” event days. Once again, 9 results from the 11 standard re-set events are statistically different from zero. The 0.05kW difference between the two approaches is not statistically significant.

The alternative methodology has the advantage of not needing a comparison group. Moreover, it foregoes the comparison group while maintaining a standard error that is on average slightly smaller in percentage terms than the comparison group standard error. The self-correction approach still avoids at least part of the bias due to specific event day characteristics not accounted for in the estimated load. The self-correction approach does all of this at a fraction of the cost of the comparison group approach.

The relative accuracy of the bias correction is impossible to quantify. The two approaches do, however, have different strengths. The comparison group, given a demonstrated similarity between re-set and comparison group, addresses potential systematic biases across every interval. On any given day, the groups might behave quite differently, thus affecting the resulting impact estimate.

The self-correction approach begins the re-set period with minimal potential bias by the nature of the pre-event correction. It does this regardless of specific event day behavior. However, the potential for bias increases through the re-set period. That is, the forced equality of the observed and estimated load just prior to the re-set event can result in a decidedly unrealistic baseline five hours later.

4.2.2 All-Sample Re-set Day Results

The 2004 and 2005 programs each had one re-set event that was not “standard” from an evaluation perspective. In both cases there was no comparison group. The self-correction approach makes impact estimates possible for these two event days. The May 3, 2004, event generated statistically significant results estimating 0.22 kW of savings. The July 12, 2005, event produced negative results. In both cases the estimated results are substantially less than what has been projected given the event characteristics. The May 3, 2004, projection was 0.64 kW and the July 12, 2005, projection was 0.13 kW.

It is difficult to assess ramifications of these results. Both of these days were atypical re-set days. The 2004 event was the first event of the season and took place on an unusually hot day in early May. The 2005 event was also the first event of the season but took place on a relatively cool day in July. These factors could fully explain different results. On the other hand, the plot of the 2005 event does indicate a dampening effect on the observed load during the re-set period. A savings of 0.13 kW is, of course, more believable than a negative result.

4.3 PROJECTED SAVINGS

Both unadjusted and adjusted savings estimates were projected for a variety of average temperature and event durations. The unadjusted projections are reported in Appendix C. The unadjusted projections only vary by temperature. The adjusted projections are reported in Appendix D. Because they are based in part on the estimation of override percent, the adjusted projections vary by temperature and event duration.

Figures 4-2 and 4-3 summarize the 2003 through 2005 adjusted projections for hours 17 and 18 for a four-hour event. Hour 17 was the hour of peak savings in 2003 and 2005, while hour 18 was the peak hour in 2004.

Figure 4-2
2003 - 2005 Hour 17 Projected Adjusted Mean Impacts vs. Average Temperature, 4-Hour Event Duration

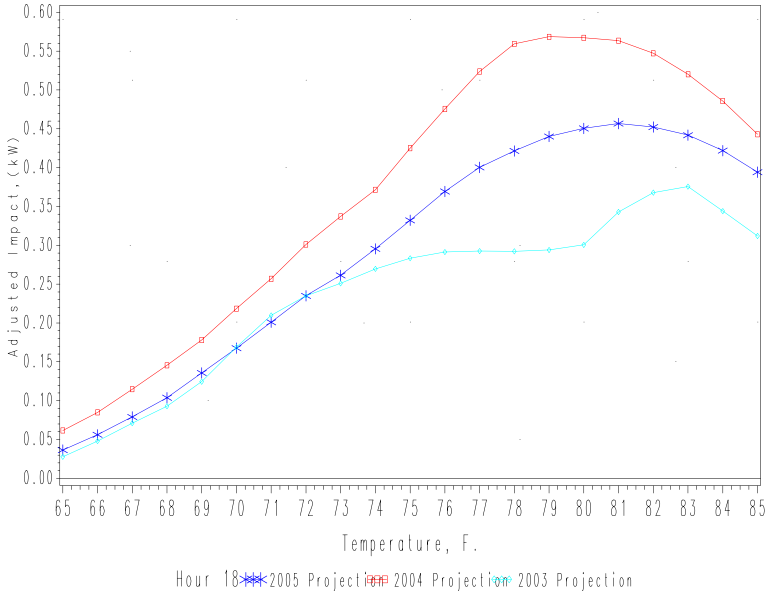
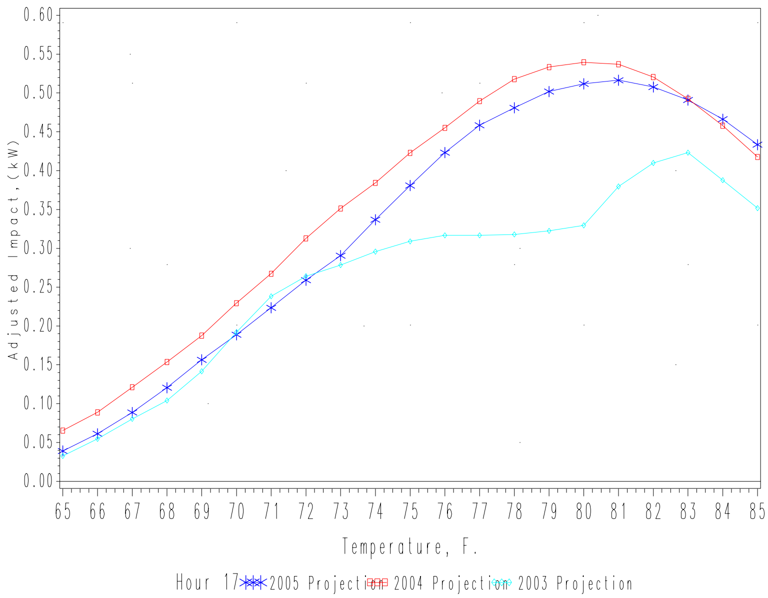


Figure 4-3
2003 - 2005 Hour 18 Projected Adjusted Mean Impacts vs. Average Temperature, 4-Hour Event Duration



The 2005 results appear to confirm the conclusion from the 2004 analysis that the 2003 results at higher temperatures were an anomaly. As is reflected in the estimated savings, the 2005 results are slightly below the 2004 results and quite similar with the 2003 results.

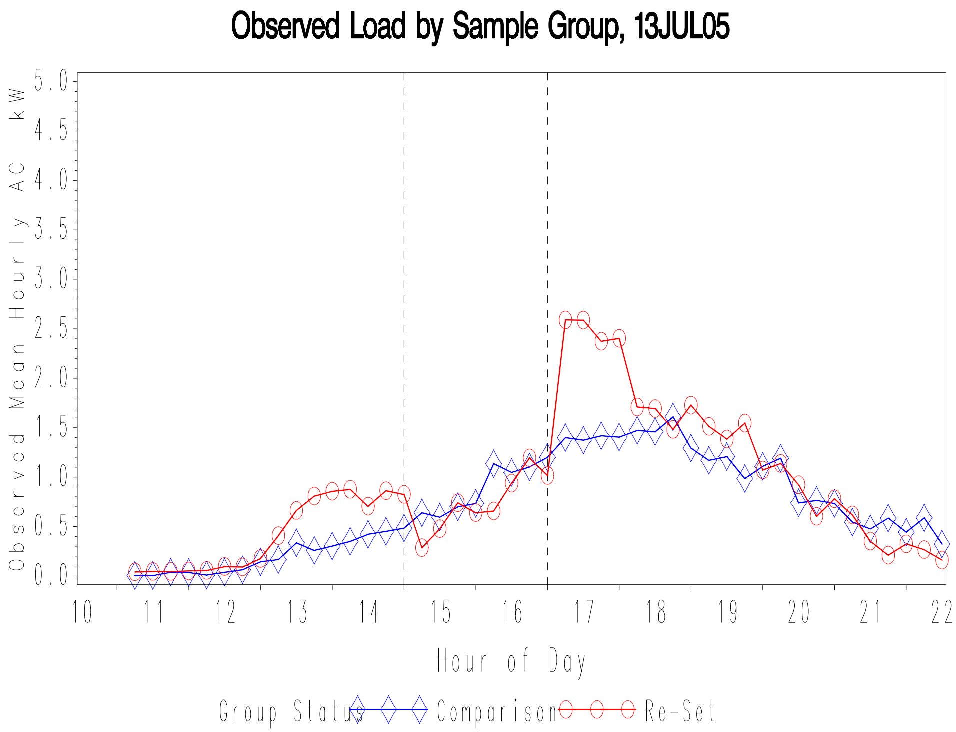
4.4 FUTURE PROGRAM PERFORMANCE

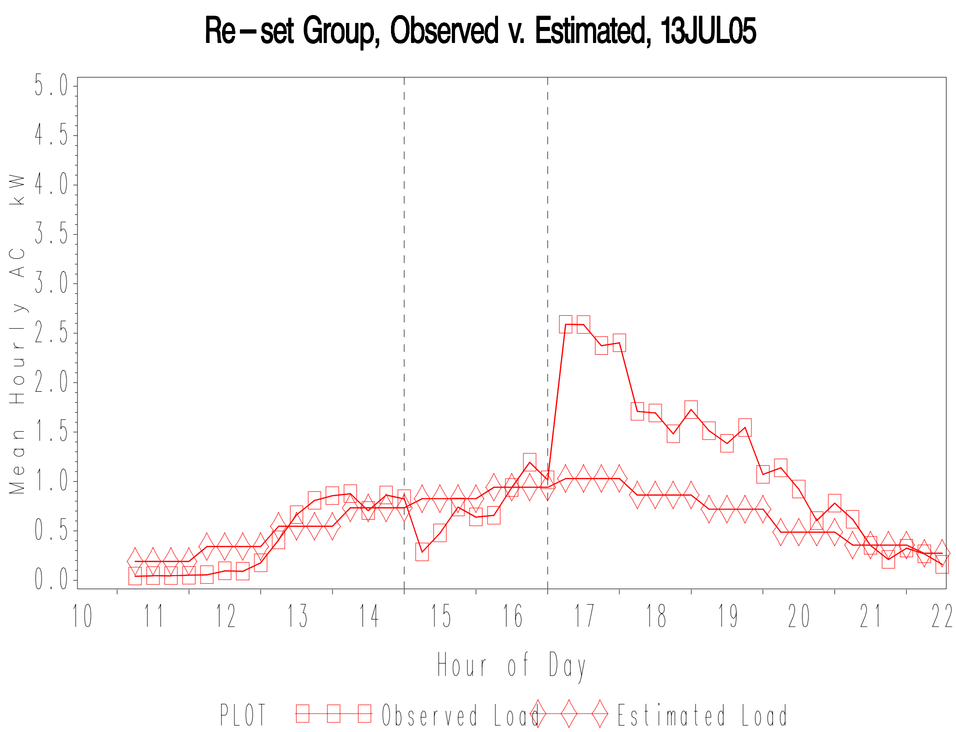
The findings from this year's analysis provide another sobering piece of evidence that the future performance of the Smart Thermostat program, as a mechanism to respond to statewide emergencies, is not fully reliable. The savings estimates for 2005 fell back to the levels experienced in 2003. This was despite temperatures that were closer to 2004 levels than 2003. The higher savings estimates of 2004 now appear to be the exception.

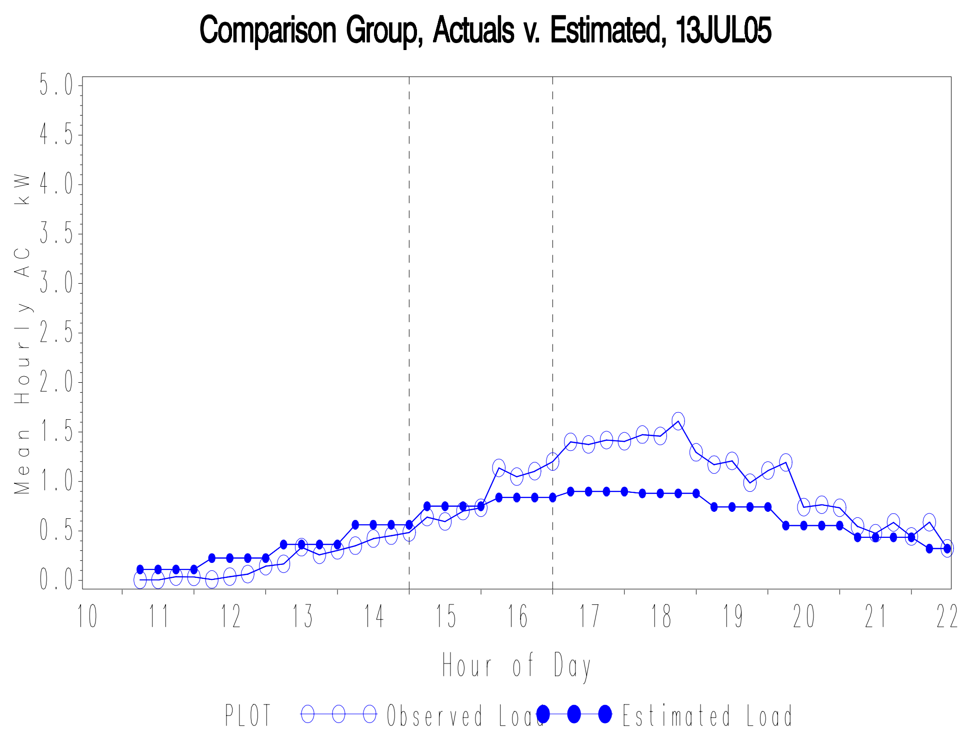
Previously, we have reported a number of factors that might explain the shortcomings of the program. One factor is the limited used of air conditioning in the territory; just under one-fifth of participating units were never used over the summer. Another factor is that statewide emergency conditions do not necessarily coincide with hot weather in the San Diego area. As long as the emergency condition that triggers a re-set event is not tied to hot weather in San Diego, a high number of non-users is likely to be found during future re-sets. Finally, when the weather is hot, higher rates of override are projected to occur. Thus, while the program is capable of savings of the desired 4 MW magnitude, it is unlikely to realize these savings in full on the day of a statewide emergency.

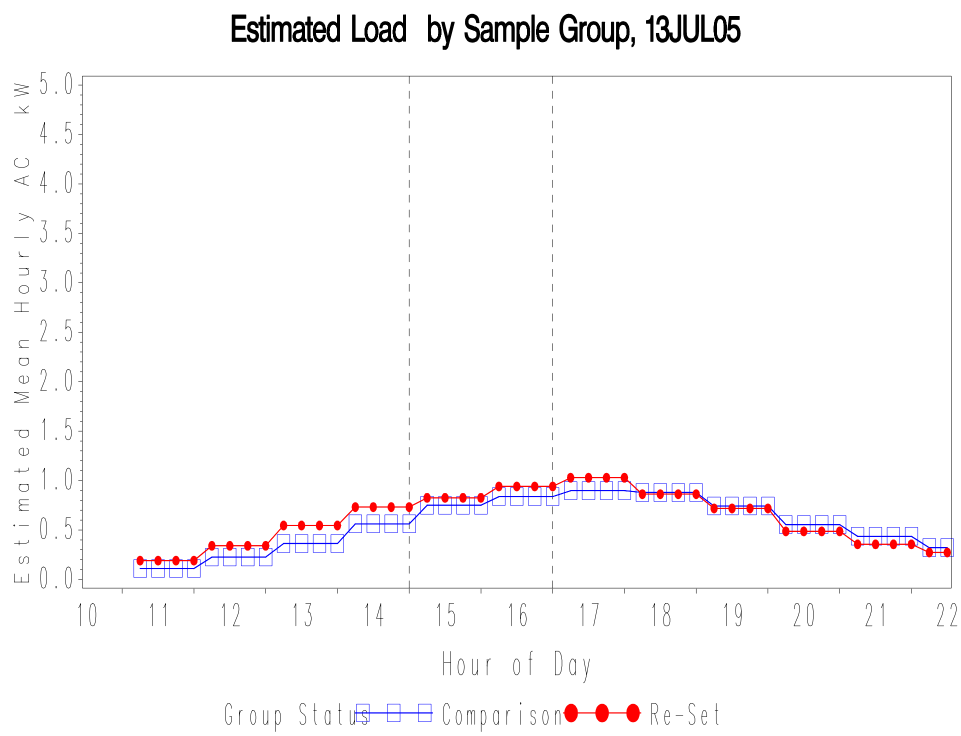
The timing of the 2005 events was more closely aligned with hot weather than in the previous two years, and still the magnitude of the savings fell from 2004. Better event timing does not appear to translate into higher impacts. This appears to indicate that the program's limitations are more a factor of San Diego's weather patterns, which is characterized by milder weather overall and short-lived hot spells and the associated cooling behavior of participants.

A AIR CONDITIONER IMPACT PLOTS

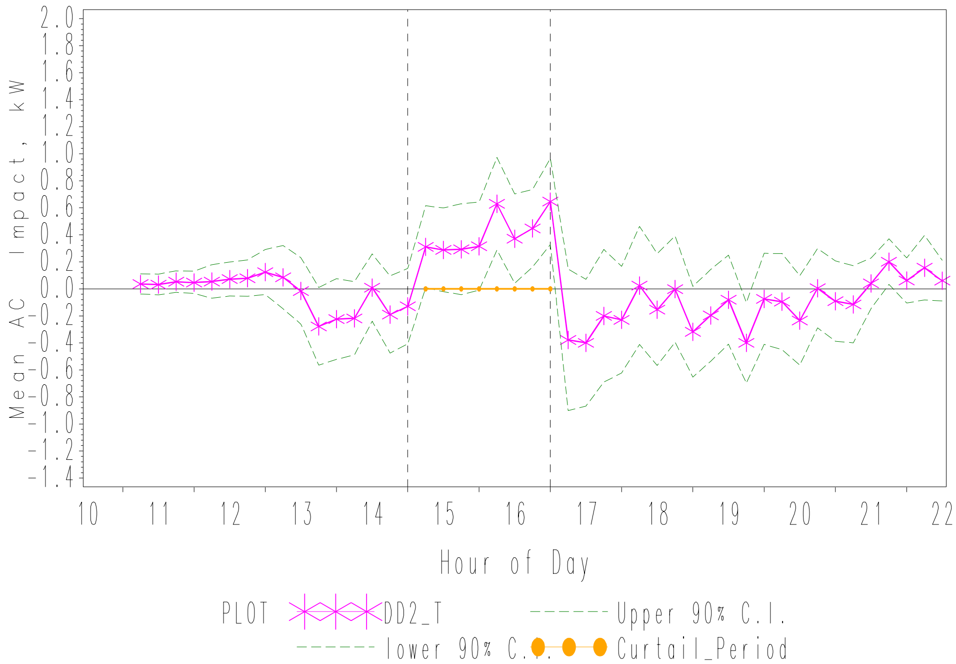




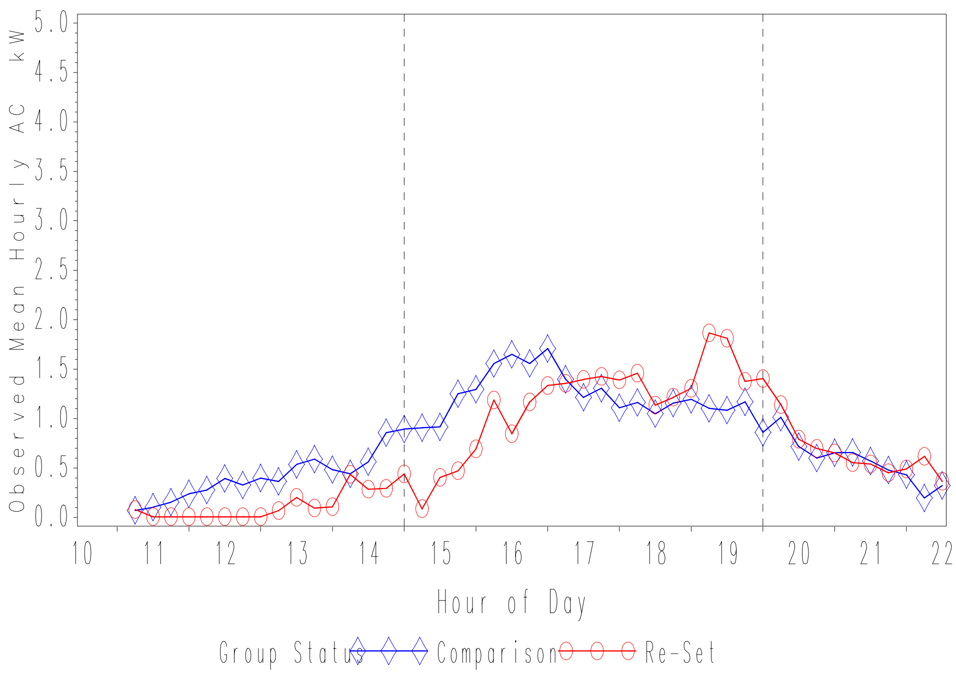

Comparison Group, Actuals v. Estimated, 13JUL05
Mean Hourly AC kW
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load


Estimated Load by Sample Group, 13JUL05
Estimated Mean Hourly AC kW
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Group Status
Comparison
Re-Set

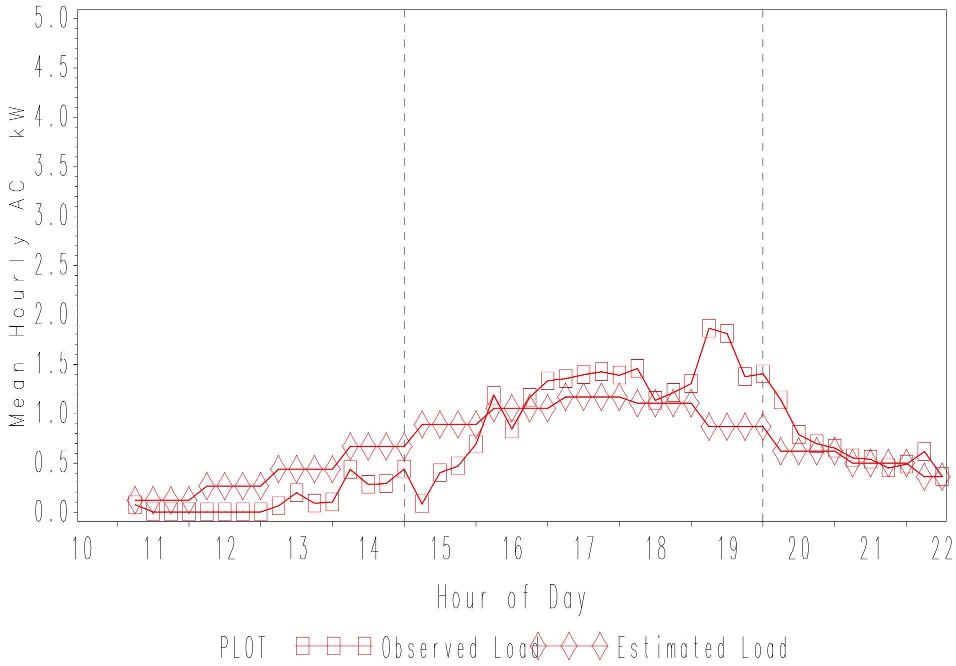
Impact Estimate for 13JUL05



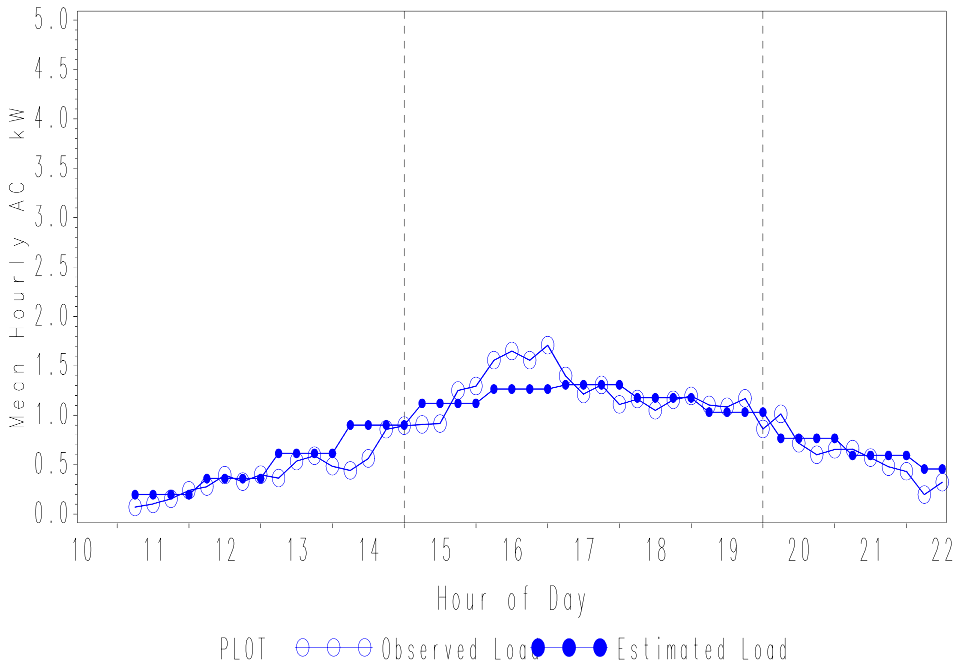
Observed Load by Sample Group, 14JUL05

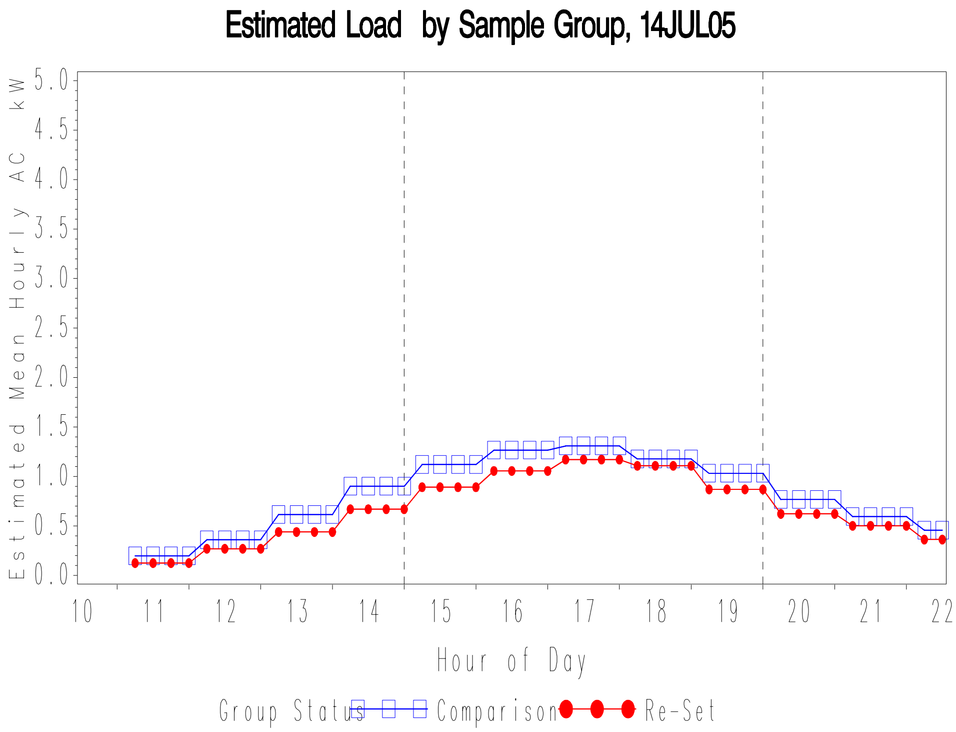


Re-set Group, Observed v. Estimated, 14JUL05

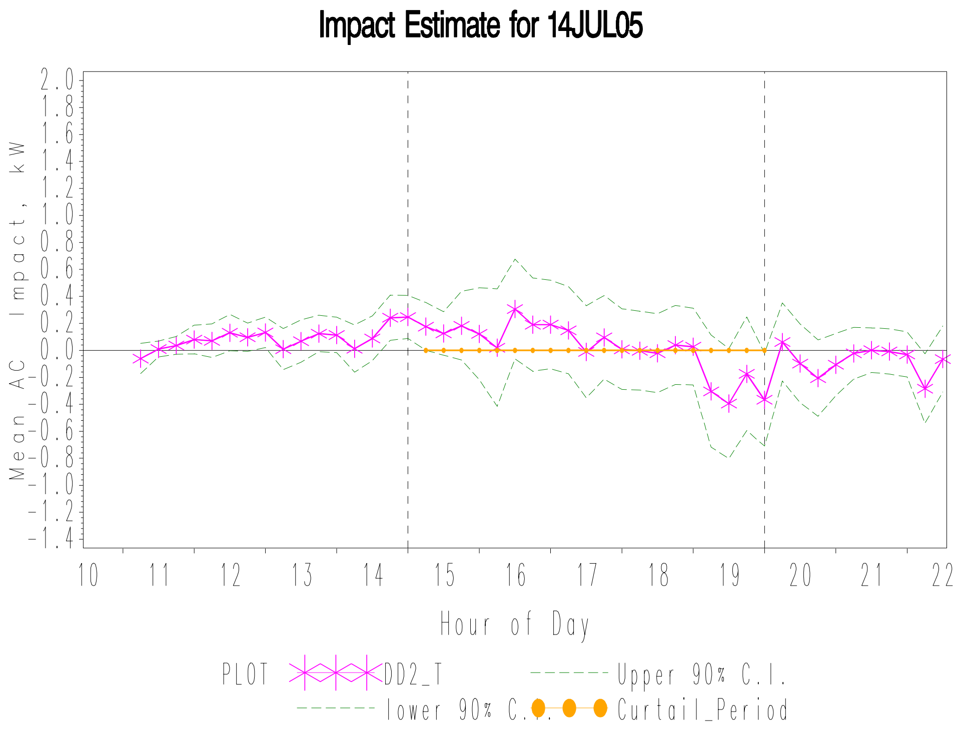


Comparison Group, Actuals v. Estimated, 14JUL05

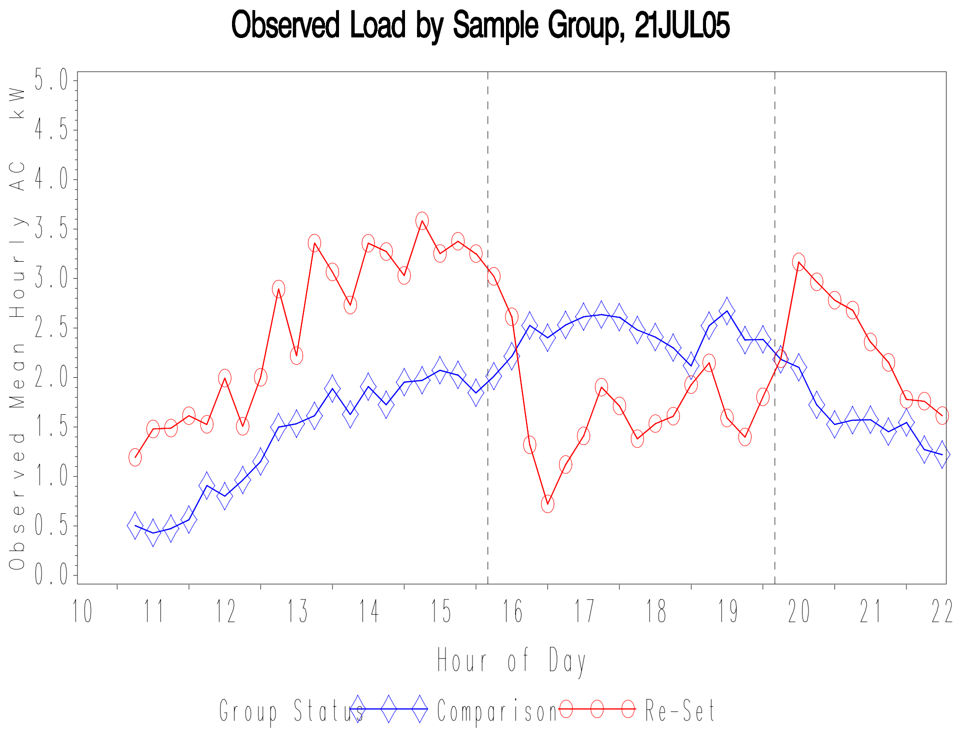


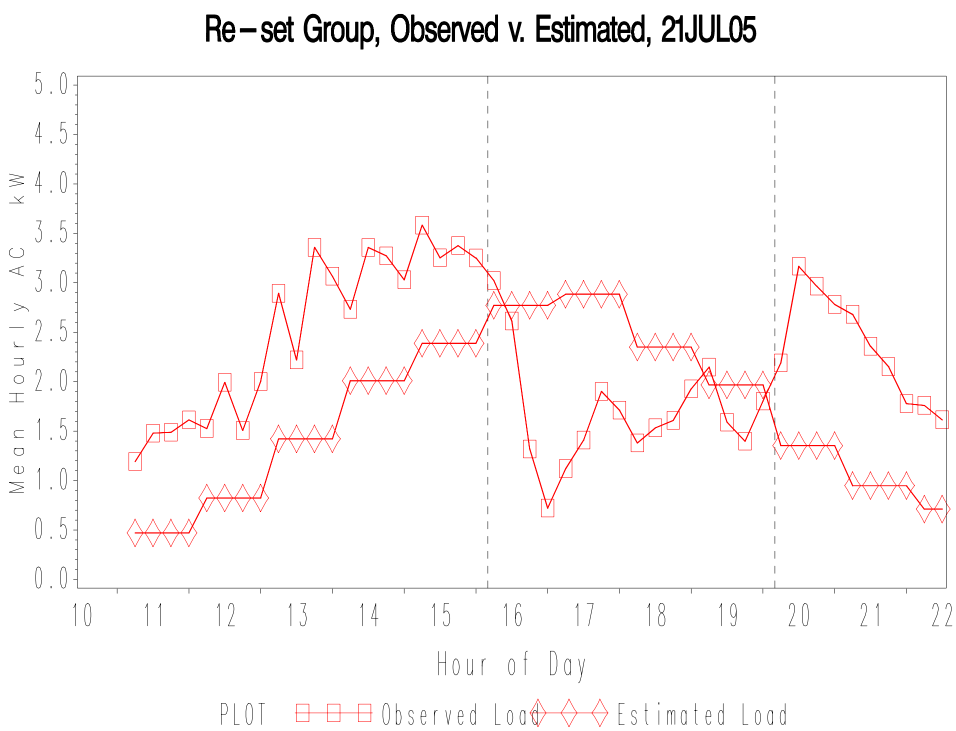


Estimated Load by Sample Group, 14JUL05
Estimated Mean Hourly AC kW
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Group Status
Comparison
Re-Set

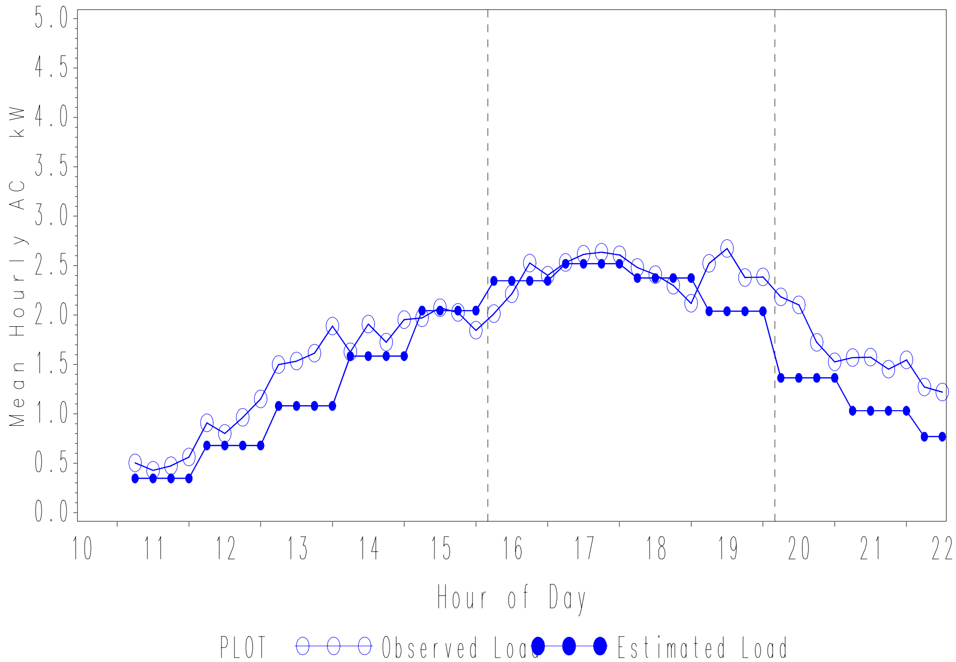


Impact Estimate for 14JUL05
Mean AC Impact, kW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
-0.6
-0.8
-1.0
-1.2
-1.4
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
DD2_T
Upper 90% C.I.
lower 90% C.I.
Curtail_Period

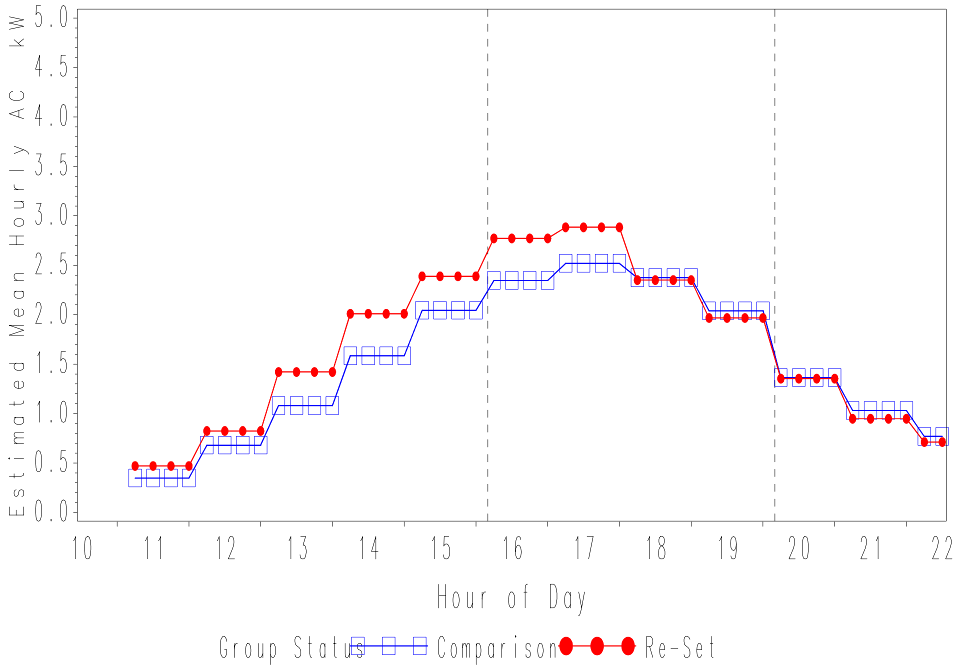

Observed Load by Sample Group, 21JUL05
Observed Mean Hourly AC kW
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Group Status
Comparison
Re-Set


Re-set Group, Observed v. Estimated, 21JUL05
Mean Hourly AC kW
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load

Comparison Group, Actuals v. Estimated, 21JUL05

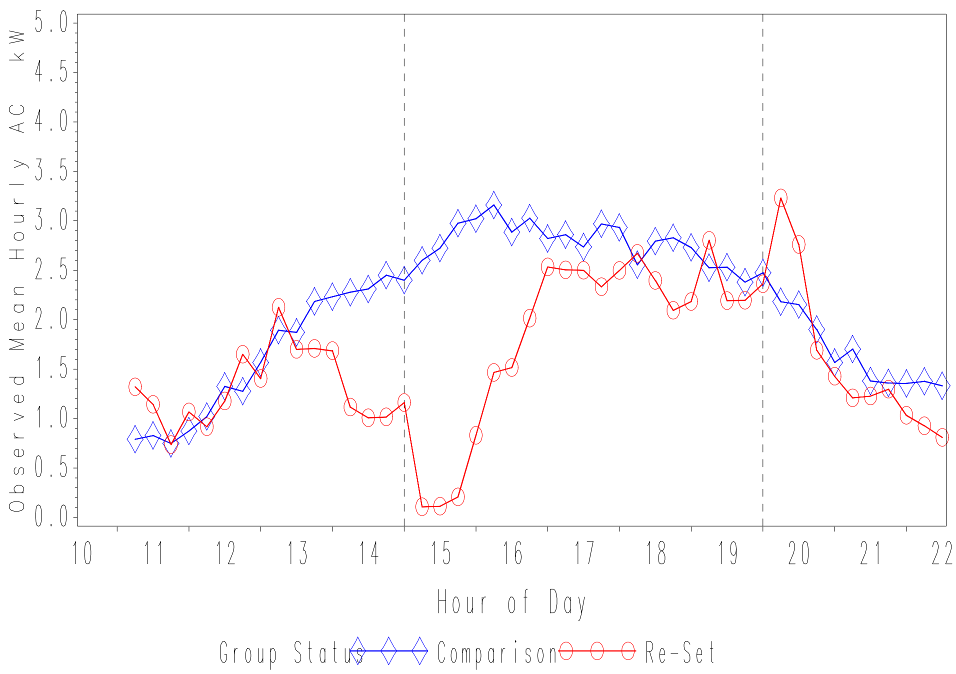


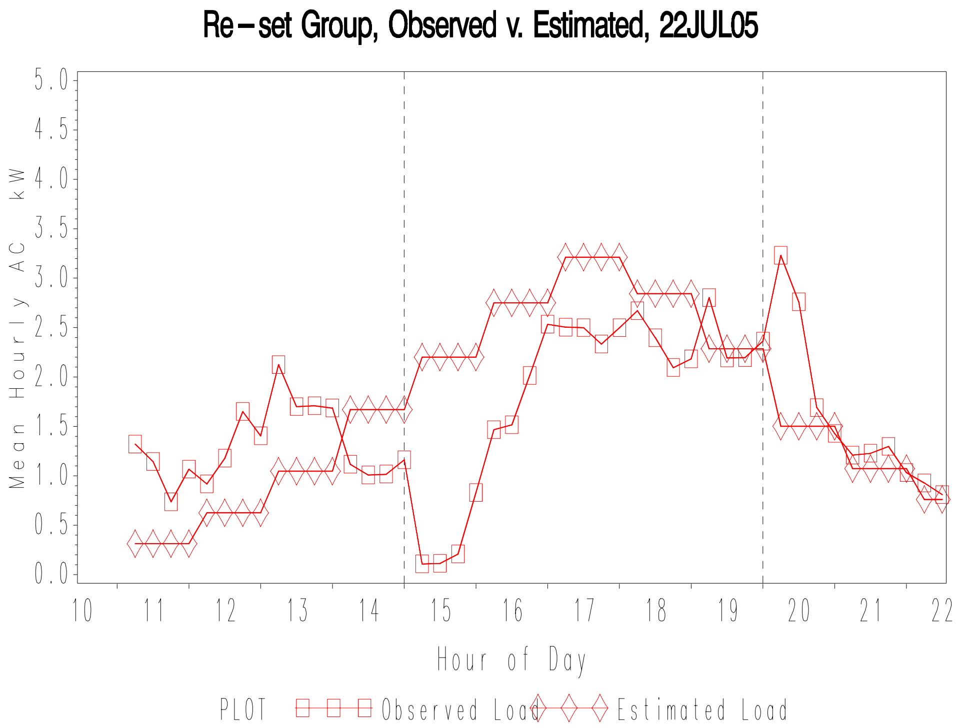
Estimated Load by Sample Group, 21JUL05

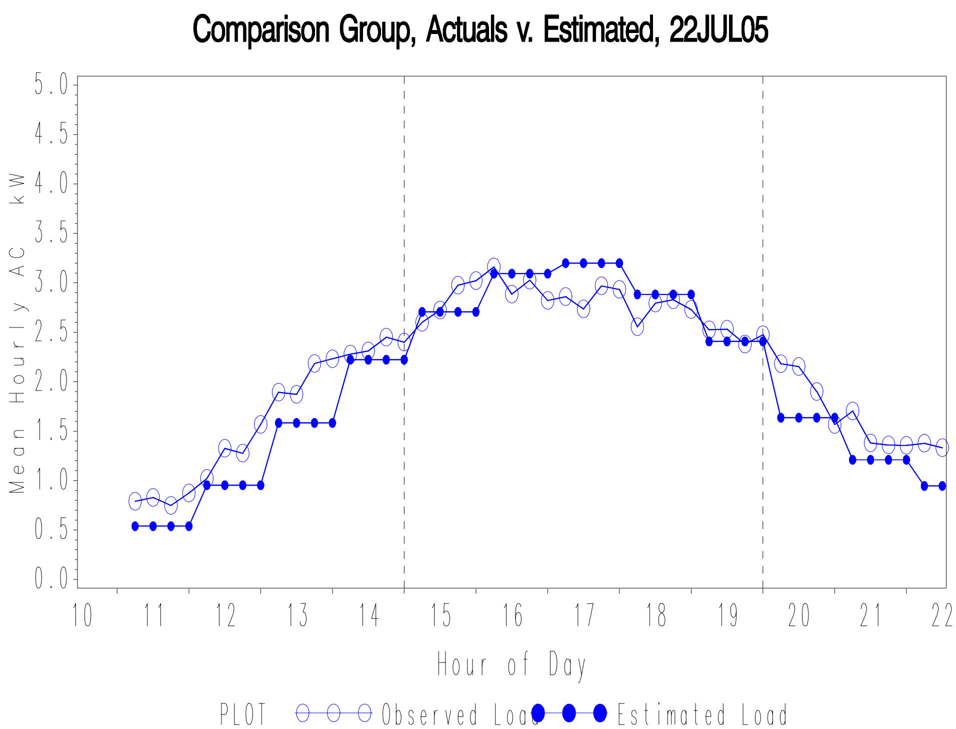


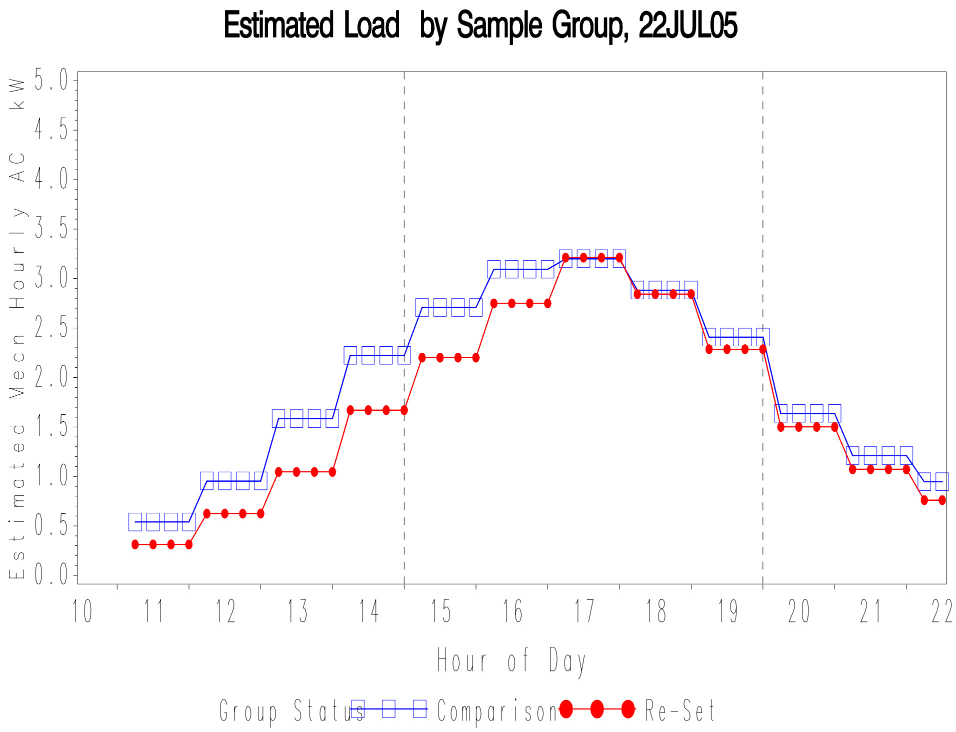
Impact Estimate for 21JUL05

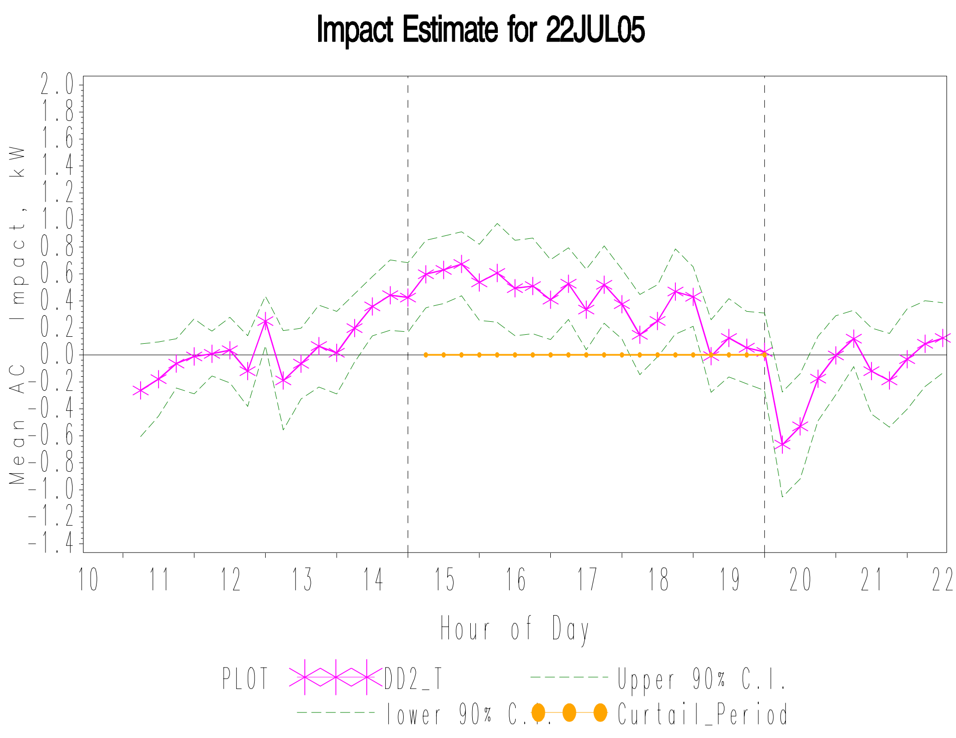
Observed Load by Sample Group, 22JUL05



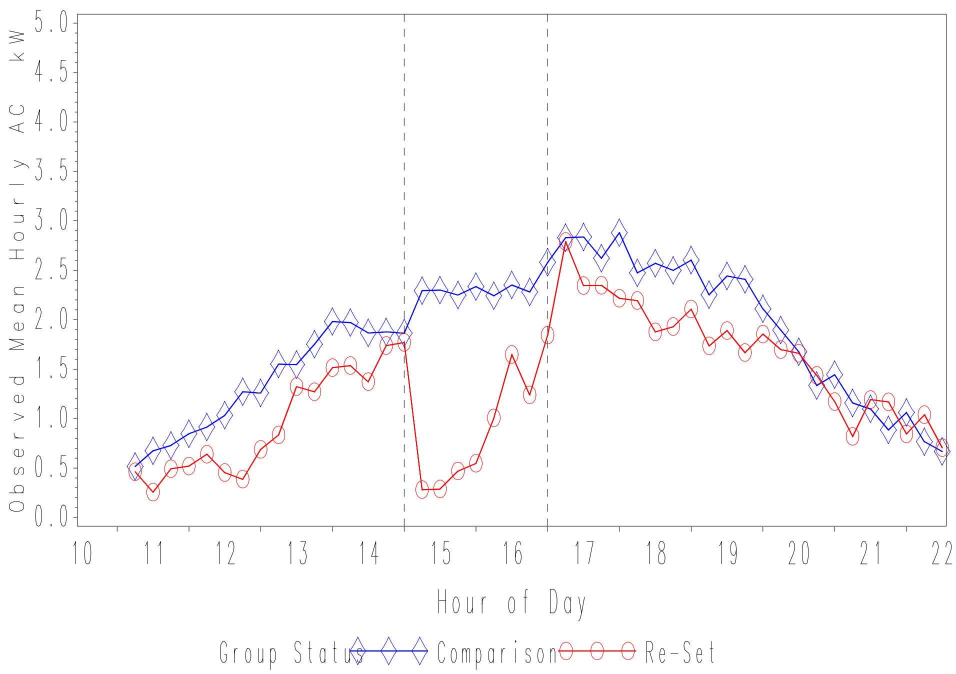

Re–set Group, Observed v. Estimated, 22JUL05
Mean Hourly AC kW
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT Observed Load Estimated Load


Comparison Group, Actuals v. Estimated, 22JUL05
Mean Hourly AC kW
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT Observed Load Estimated Load

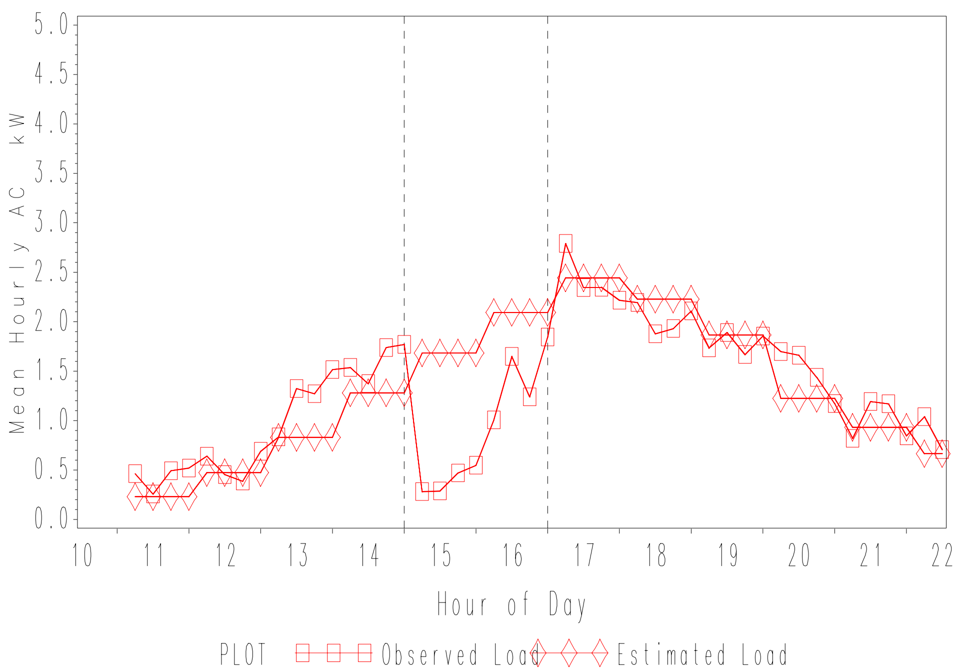

Estimated Load by Sample Group, 22JUL05
Estimated Mean Hourly AC kW
5.0 4.5 4.0 3.5 3.0 2.5 2.0 1.5 1.0 0.5 0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Group Status Comparison Re-Set


Impact Estimate for 22JUL05
Mean AC Impact, kW
2.0 1.8 1.6 1.4 1.2 1.0 0.8 0.6 0.4 0.2 0.0 -0.2 -0.4 -0.6 -0.8 -1.0 -1.2 -1.4
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT DD2_T Upper 90% C.I.
lower 90% C.I. Curtail_Period

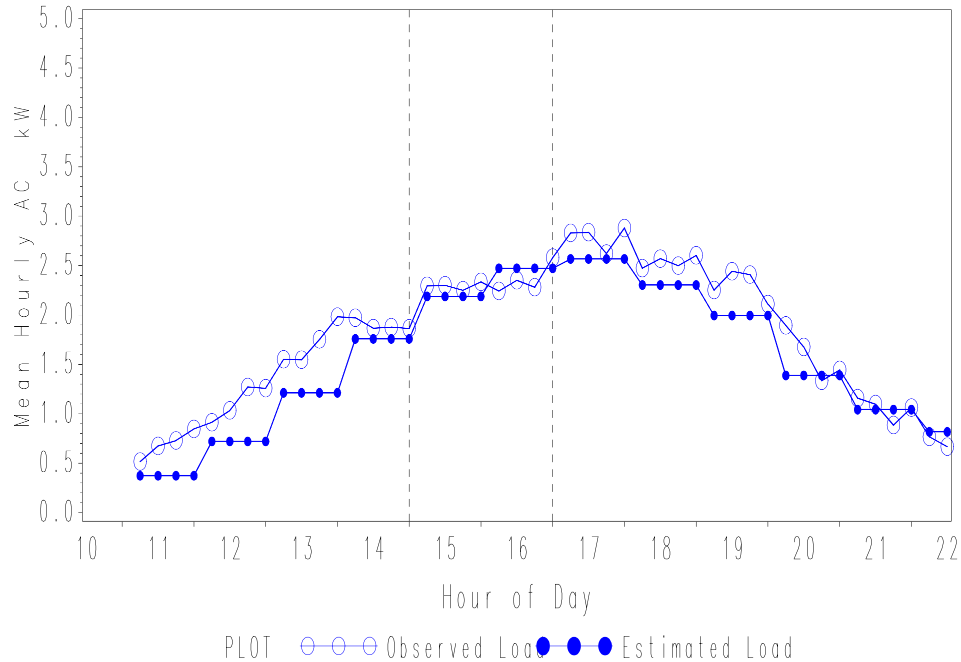
Observed Load by Sample Group, 26AUG05



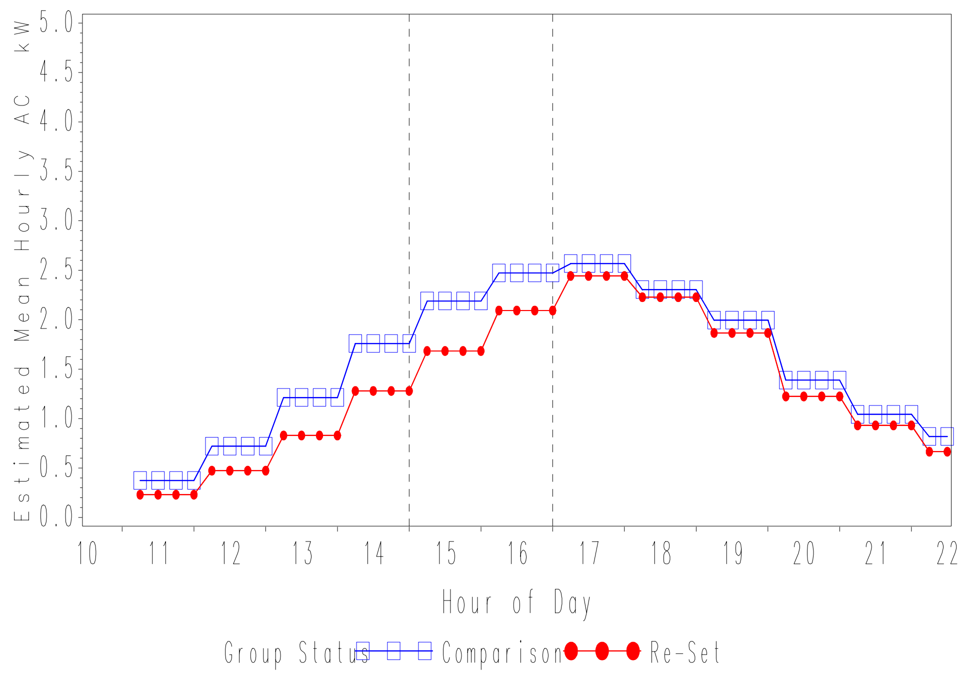
Re-set Group, Observed v. Estimated, 26AUG05



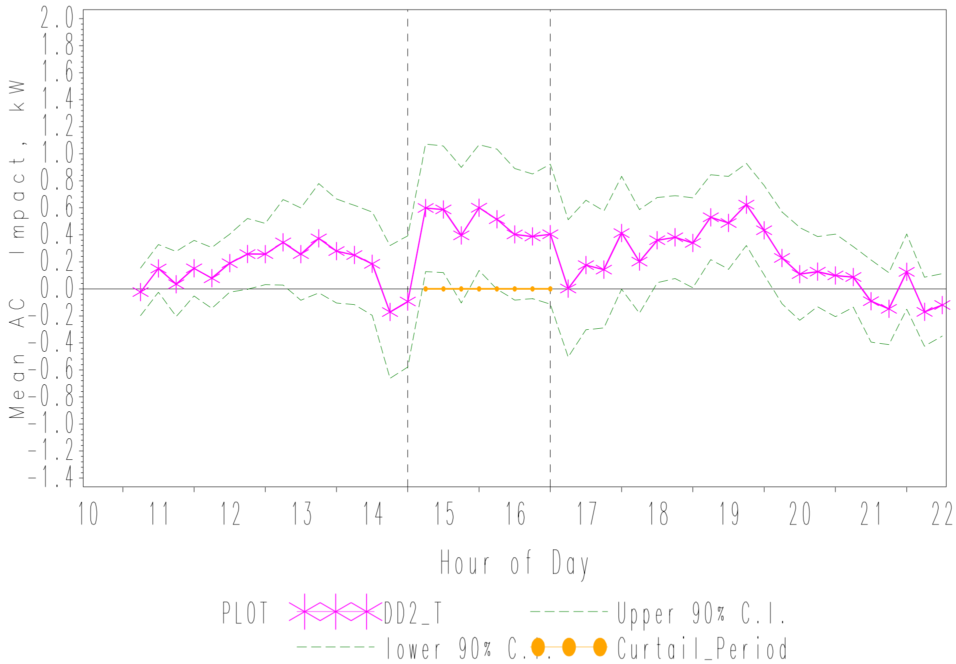
Comparison Group, Actuals v. Estimated, 26AUG05



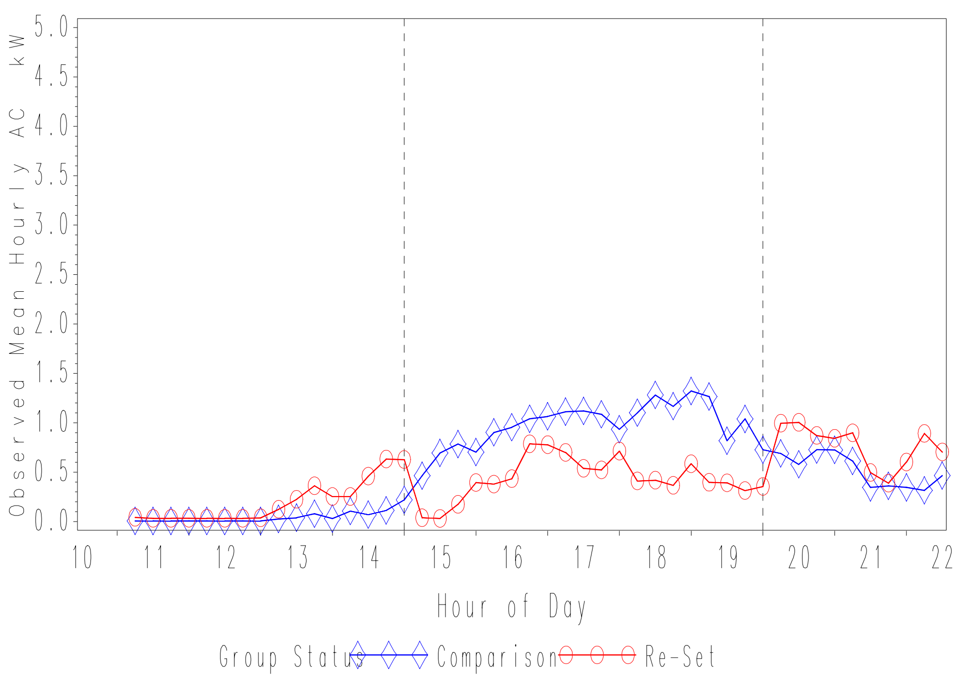
Estimated Load by Sample Group, 26AUG05

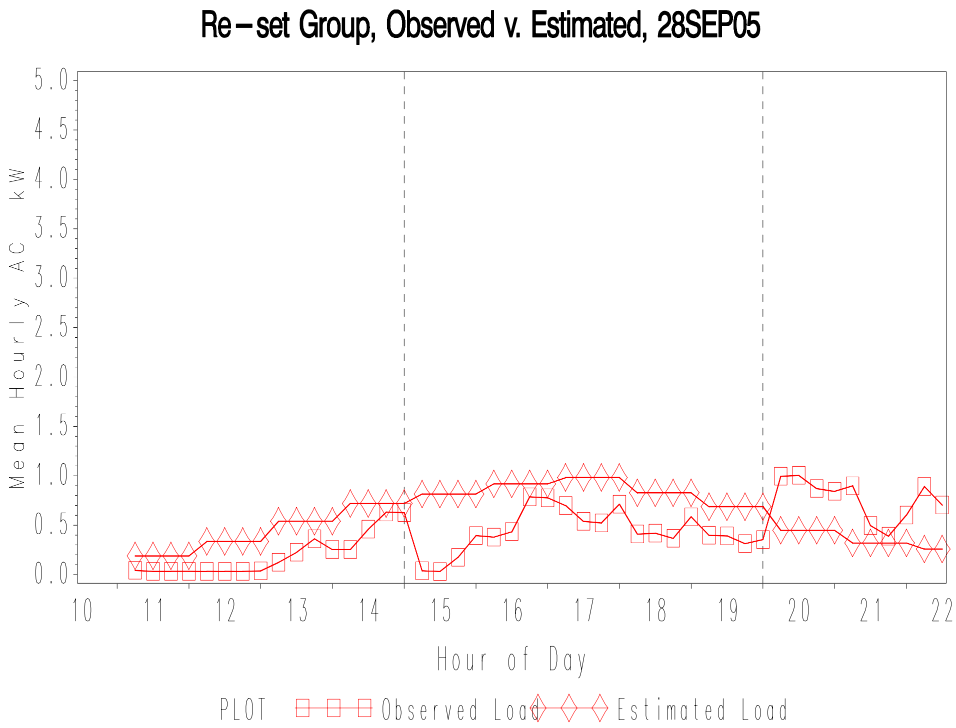


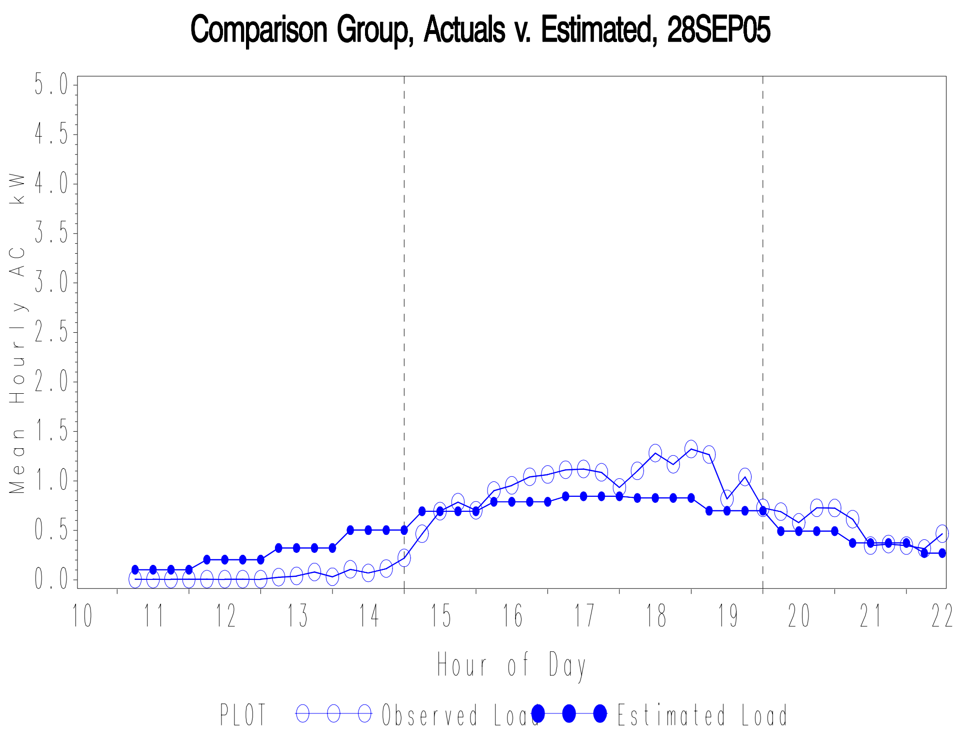
Impact Estimate for 26AUG05

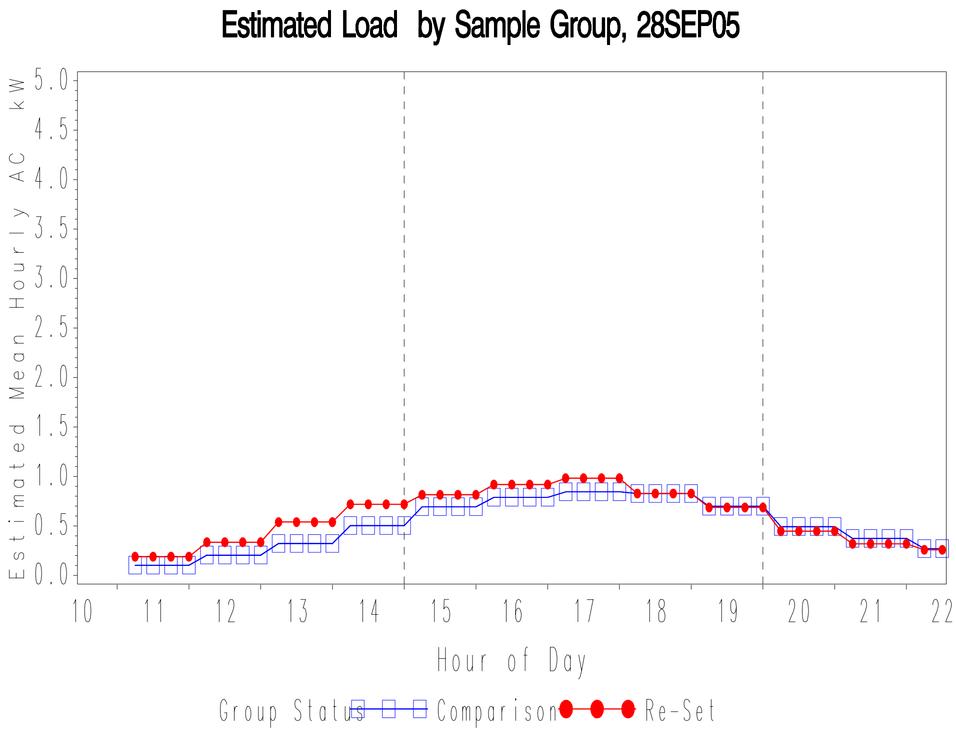


Observed Load by Sample Group, 28SEP05

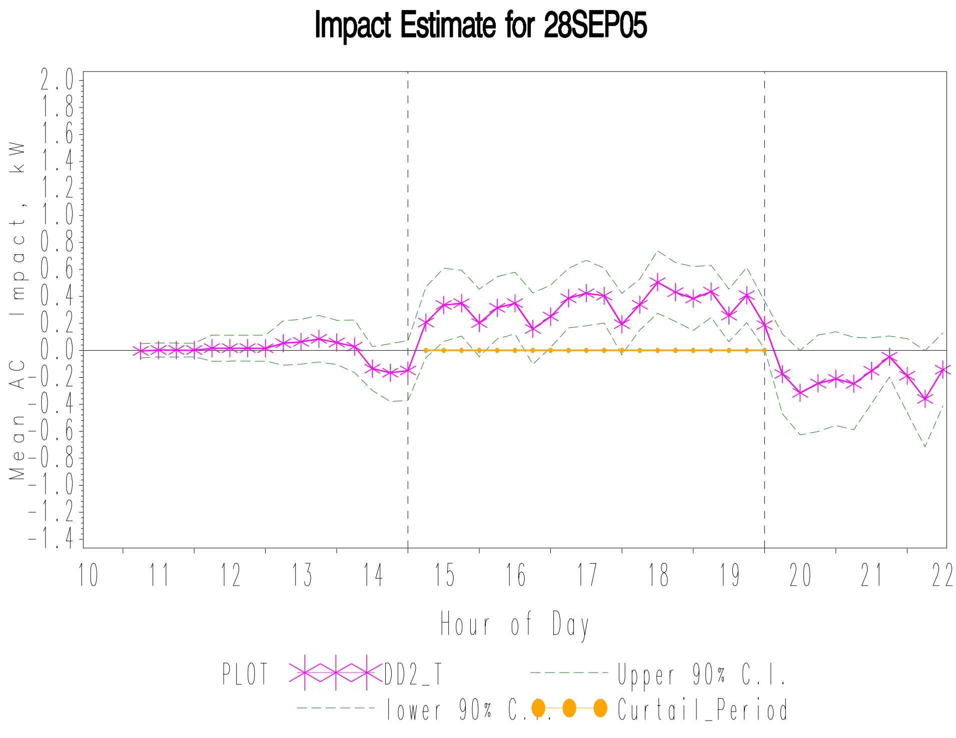



Re–set Group, Observed v. Estimated, 28SEP05
Mean Hourly AC kW
0.0 0.5 1.0 1.5 2.0 2.5 3.0 3.5 4.0 4.5 5.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT Observed Load Estimated Load


Comparison Group, Actuals v. Estimated, 28SEP05
Mean Hourly AC kW
0.0 0.5 1.0 1.5 2.0 2.5 3.0 3.5 4.0 4.5 5.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT Observed Load Estimated Load

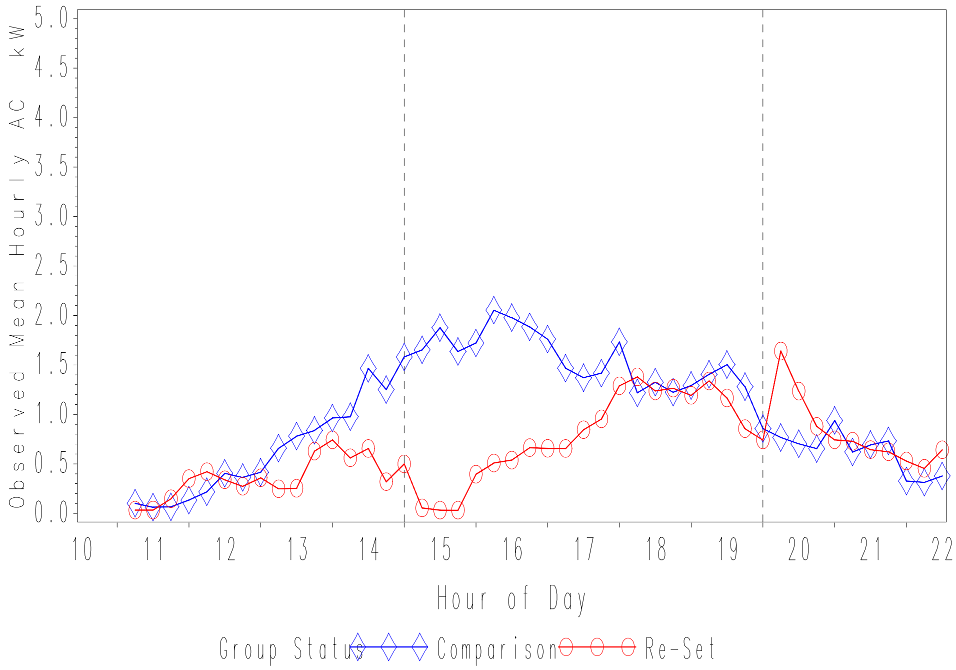


Estimated Load by Sample Group, 28SEP05
Estimated Mean Hourly AC kW
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Group Status
Comparison
Re-Set

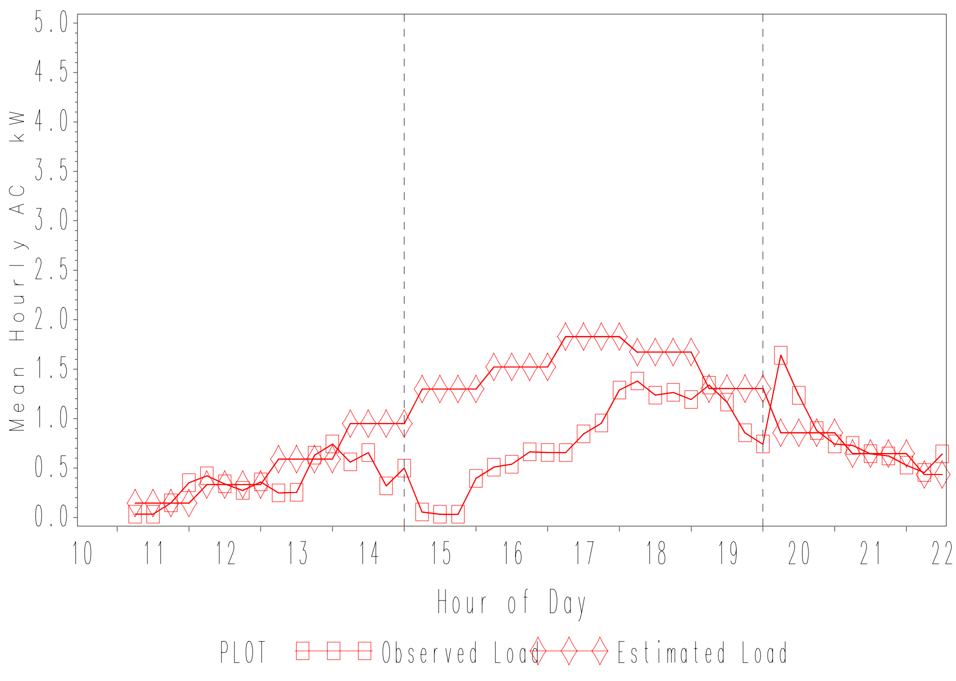


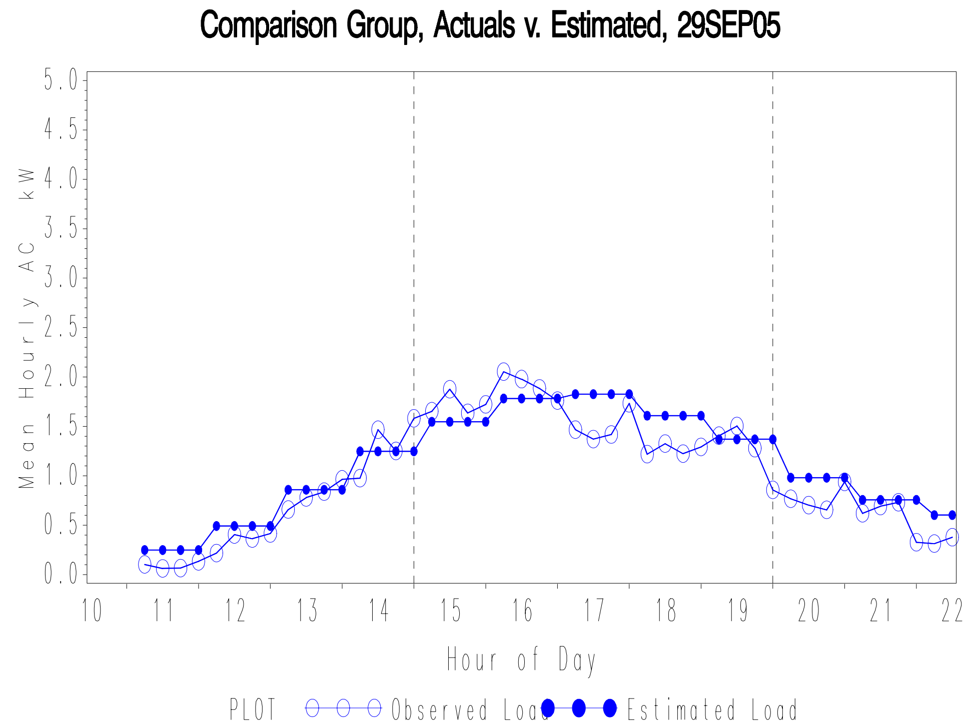
Impact Estimate for 28SEP05
Mean AC Impact, kW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
-0.6
-0.8
-1.0
-1.2
-1.4
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
DD2_T
Upper 90% C.I.
lower 90% C.I.
Curtail_Period

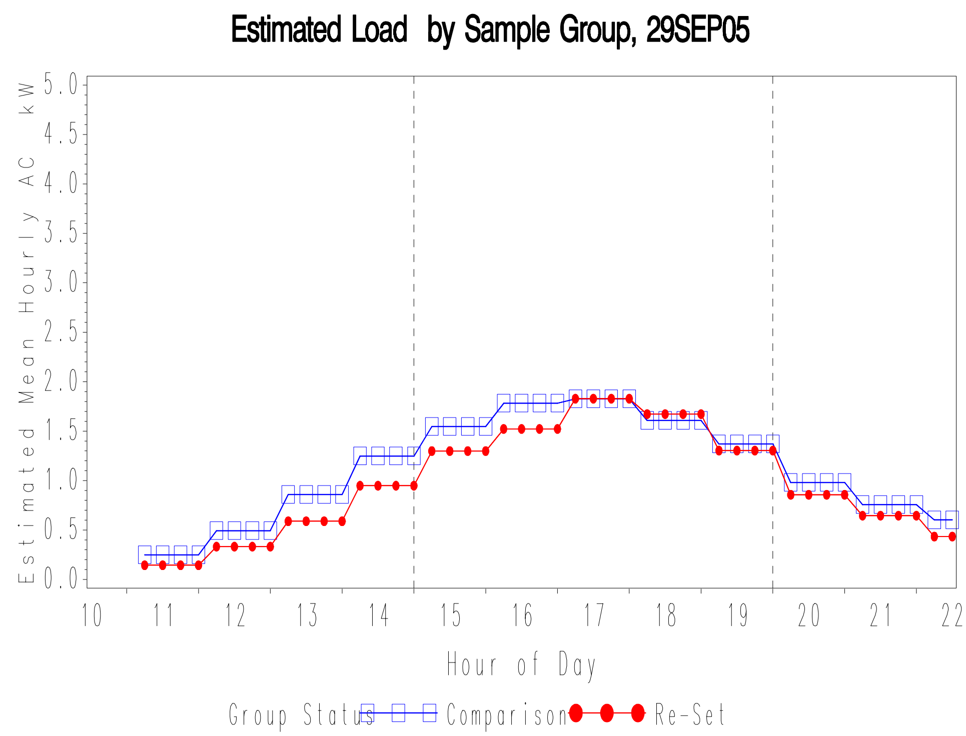
Observed Load by Sample Group, 29SEP05



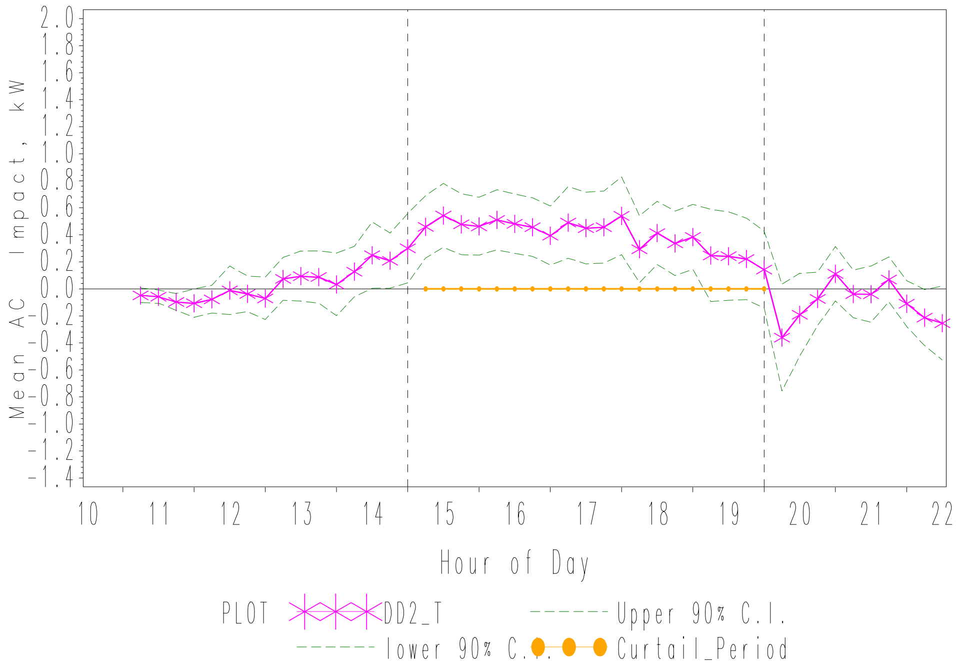
Re-set Group, Observed v. Estimated, 29SEP05



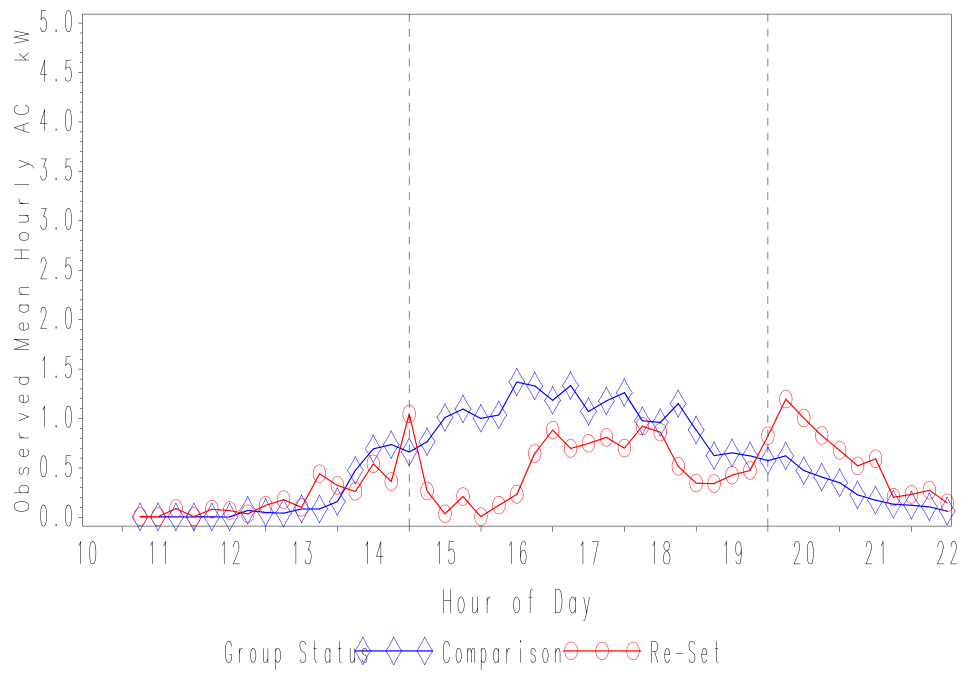

Comparison Group, Actuals v. Estimated, 29SEP05
Mean Hourly AC kW
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load

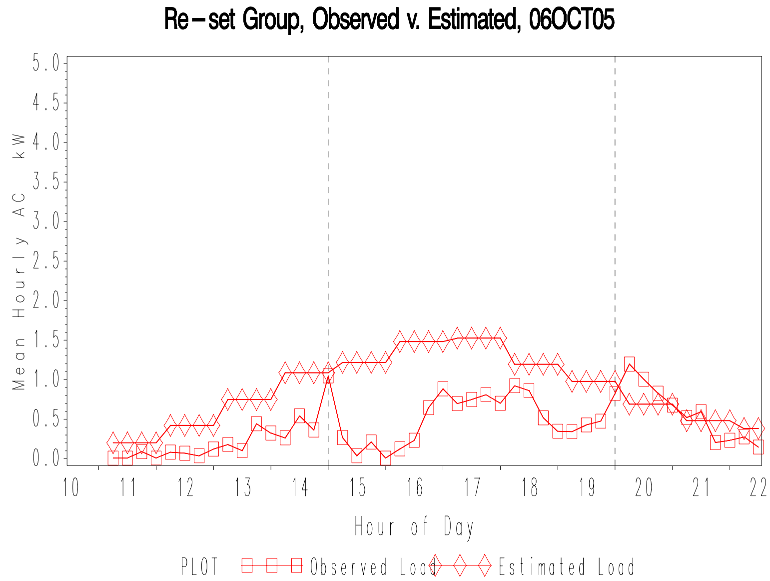

Estimated Load by Sample Group, 29SEP05
Estimated Mean Hourly AC kW
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Group Status
Comparison
Re-Set

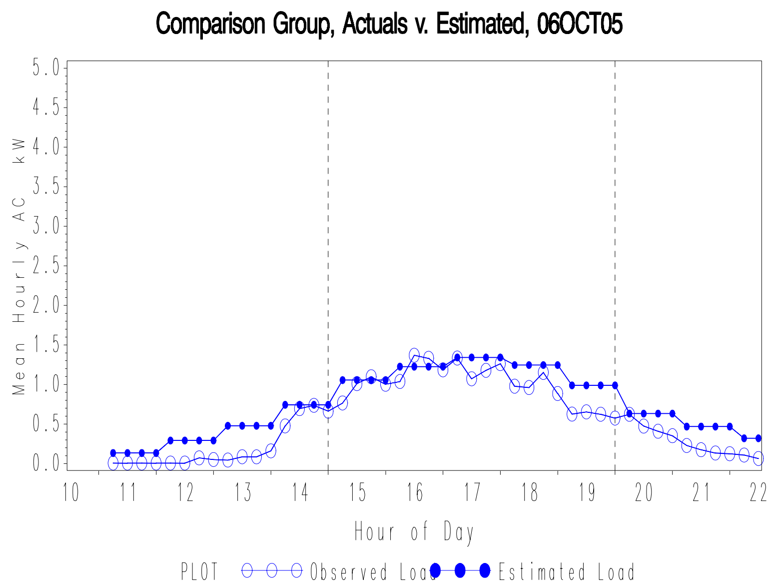
Impact Estimate for 29SEP05



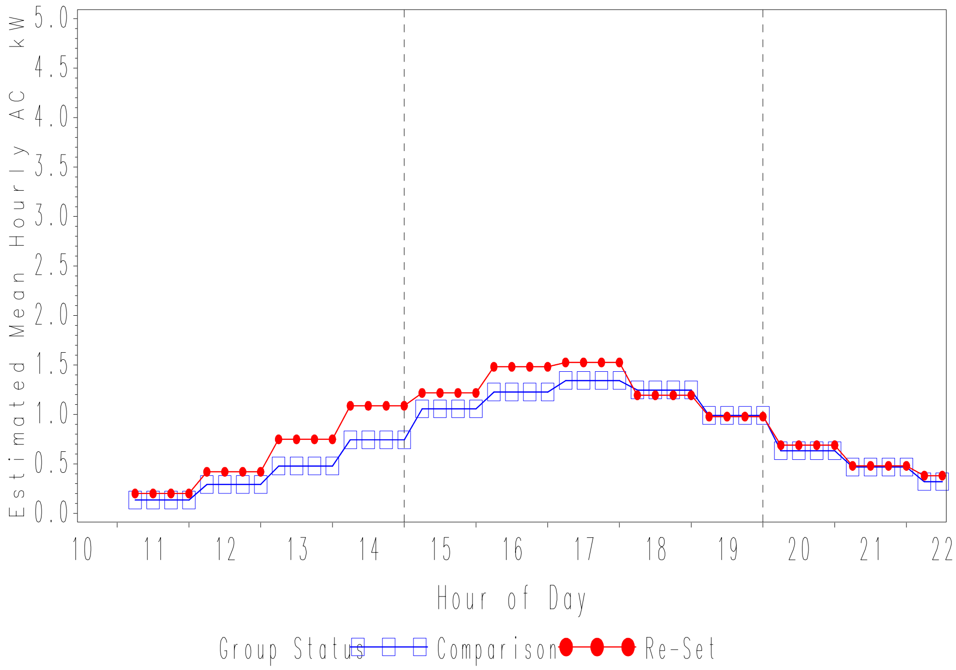
Observed Load by Sample Group, 06OCT05



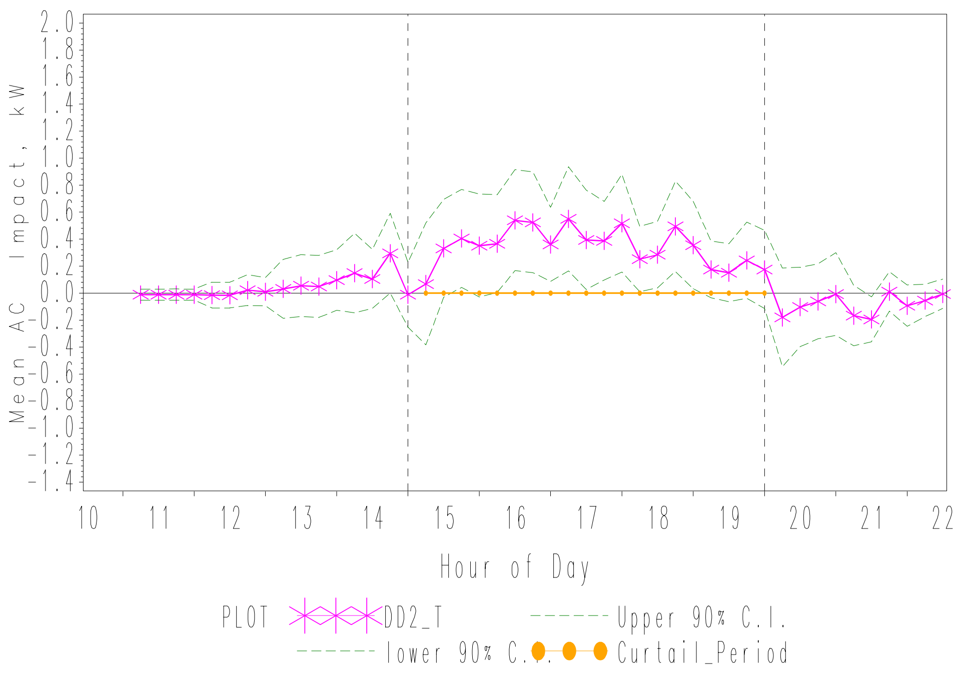

Re-set Group, Observed v. Estimated, 06OCT05
Mean Hourly AC kW
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT Observed Load Estimated Load


Comparison Group, Actuals v. Estimated, 06OCT05
Mean Hourly AC kW
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT Observed Load Estimated Load

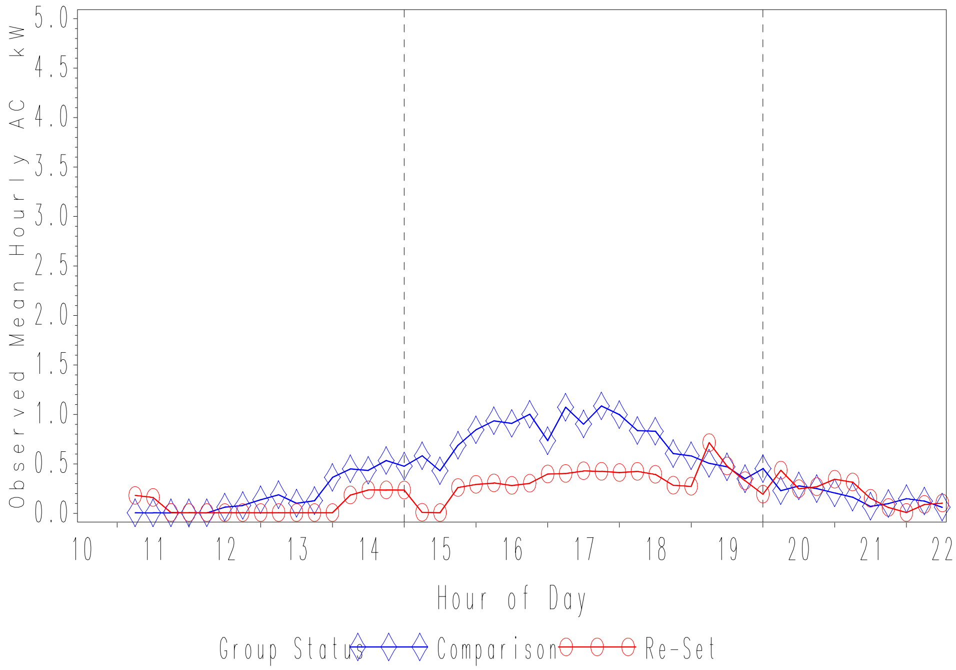
Estimated Load by Sample Group, 06OCT05



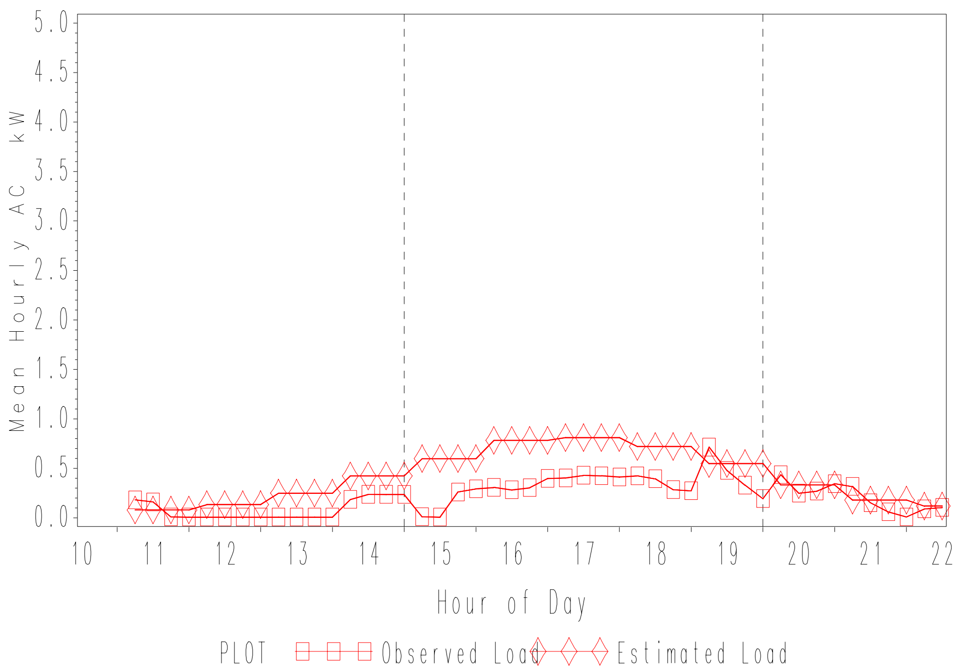
Impact Estimate for 06OCT05

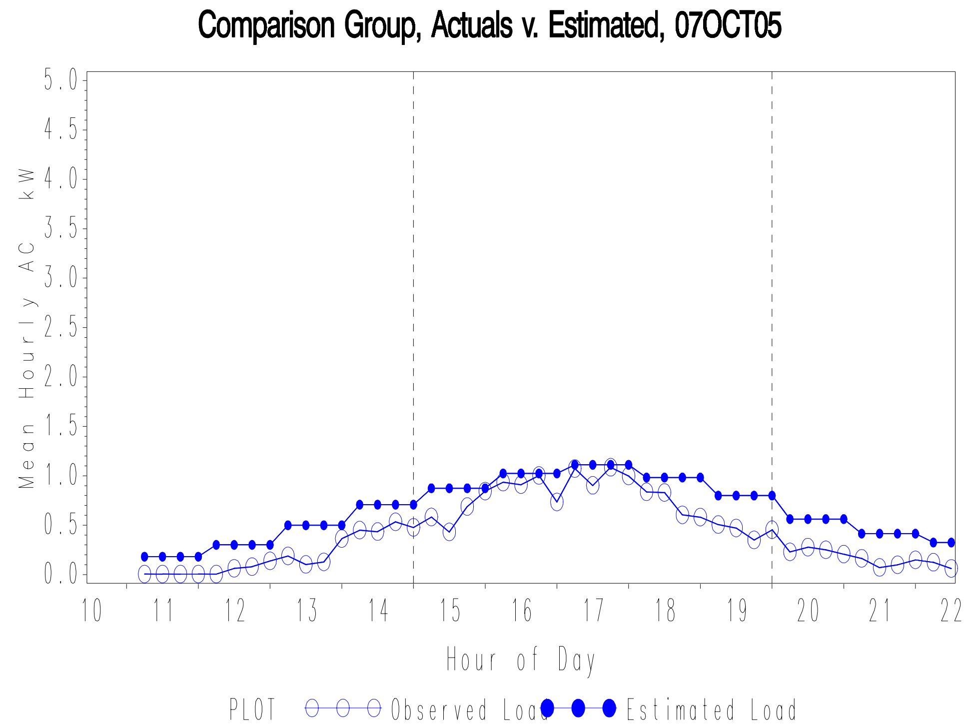


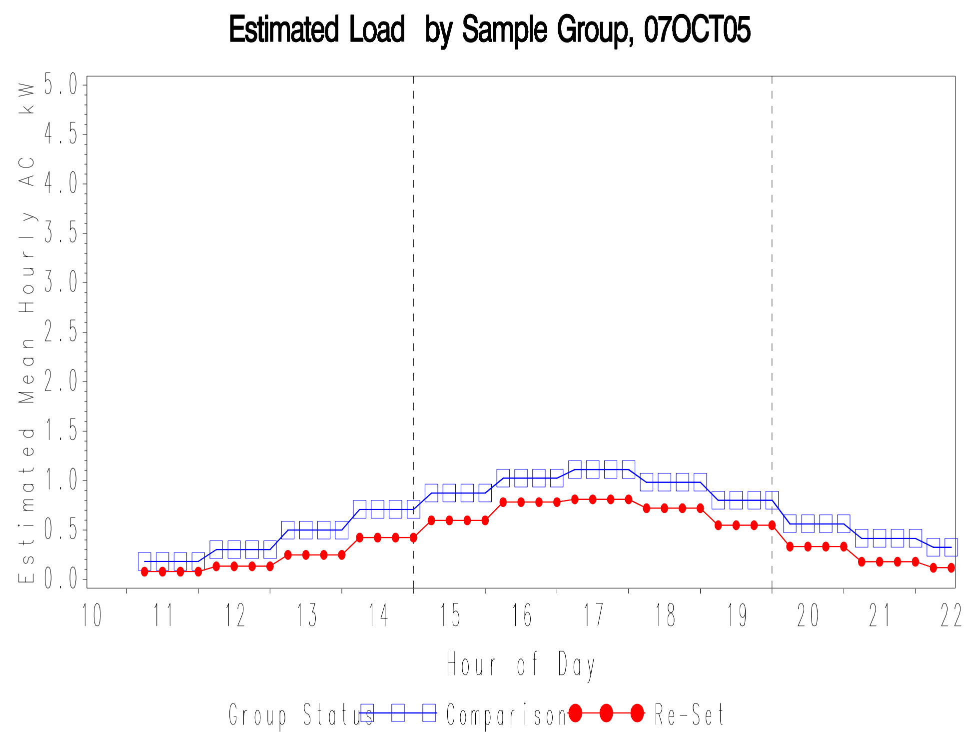
Observed Load by Sample Group, 07OCT05

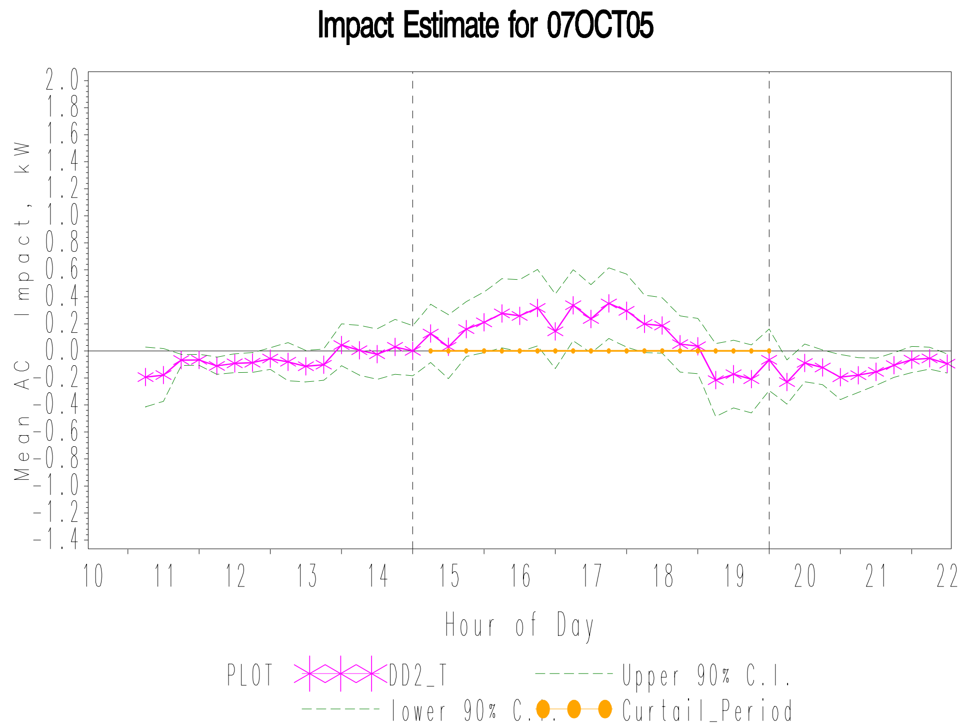


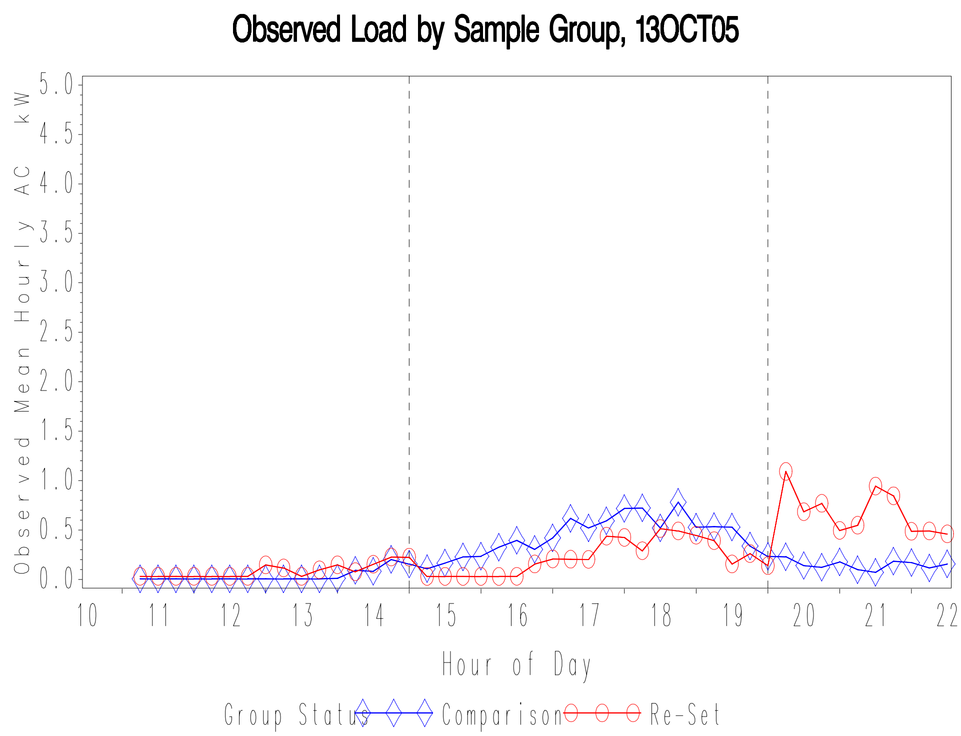
Re-set Group, Observed v. Estimated, 07OCT05

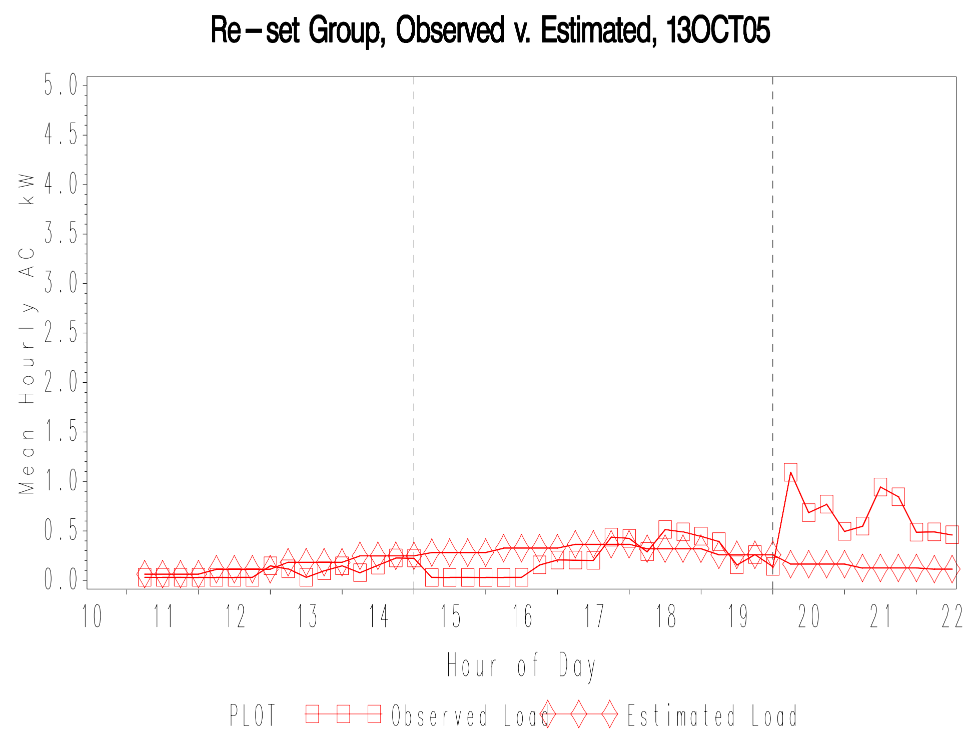


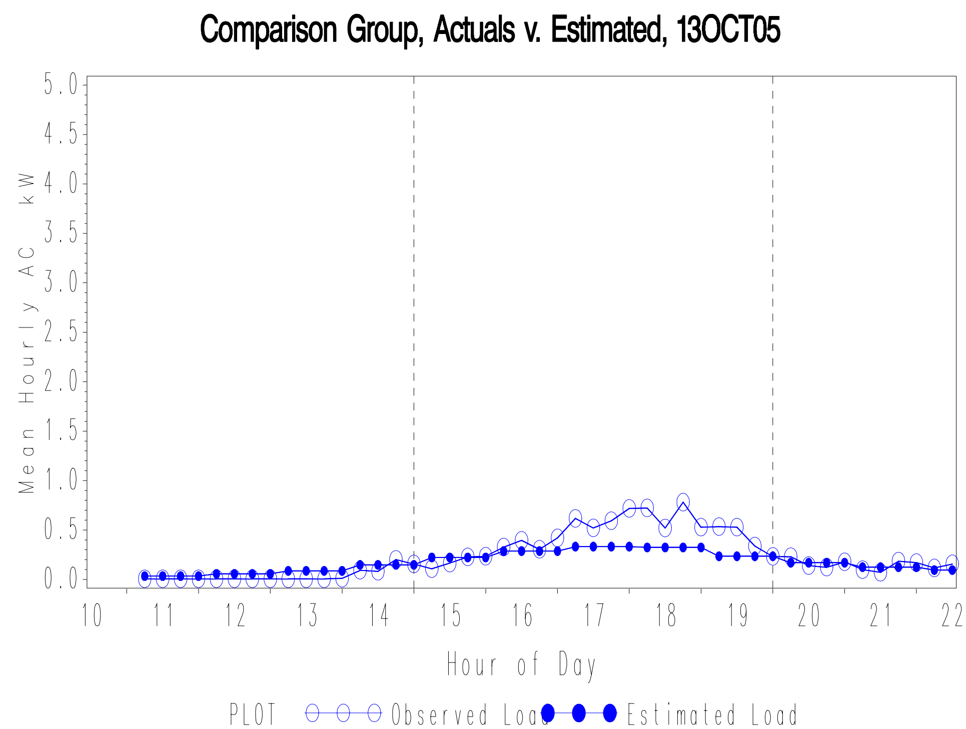

Comparison Group, Actuals v. Estimated, 07OCT05
Mean Hourly AC kW
Hour of Day
PLOT Observed Load Estimated Load

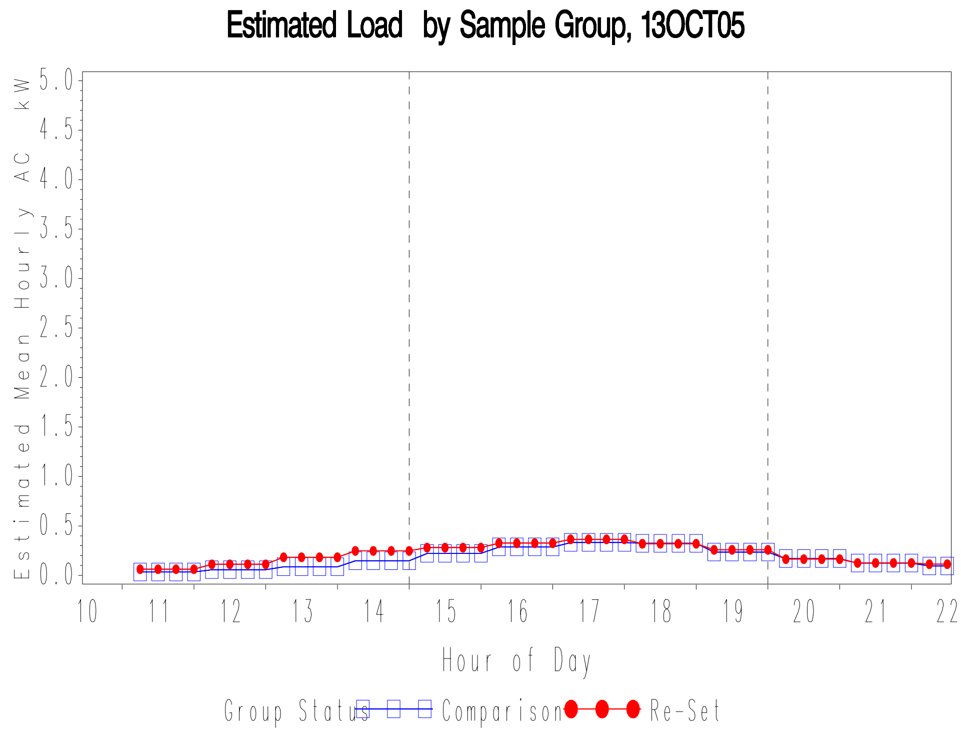

Estimated Load by Sample Group, 07OCT05
Estimated Mean Hourly AC kW
Hour of Day
Group Status Comparison Re-Set

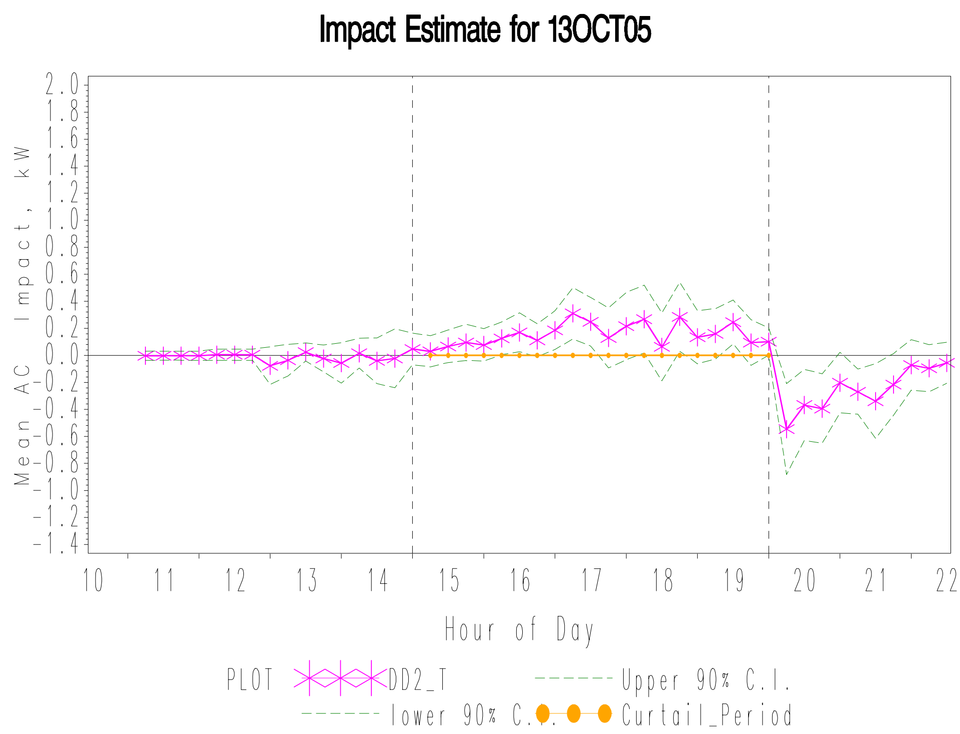

Impact Estimate for 07OCT05
Mean AC Impact, kW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
-0.6
-0.8
-1.0
-1.2
-1.4
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT DD2_T Upper 90% C.I.
lower 90% C.I. Curtail_Period

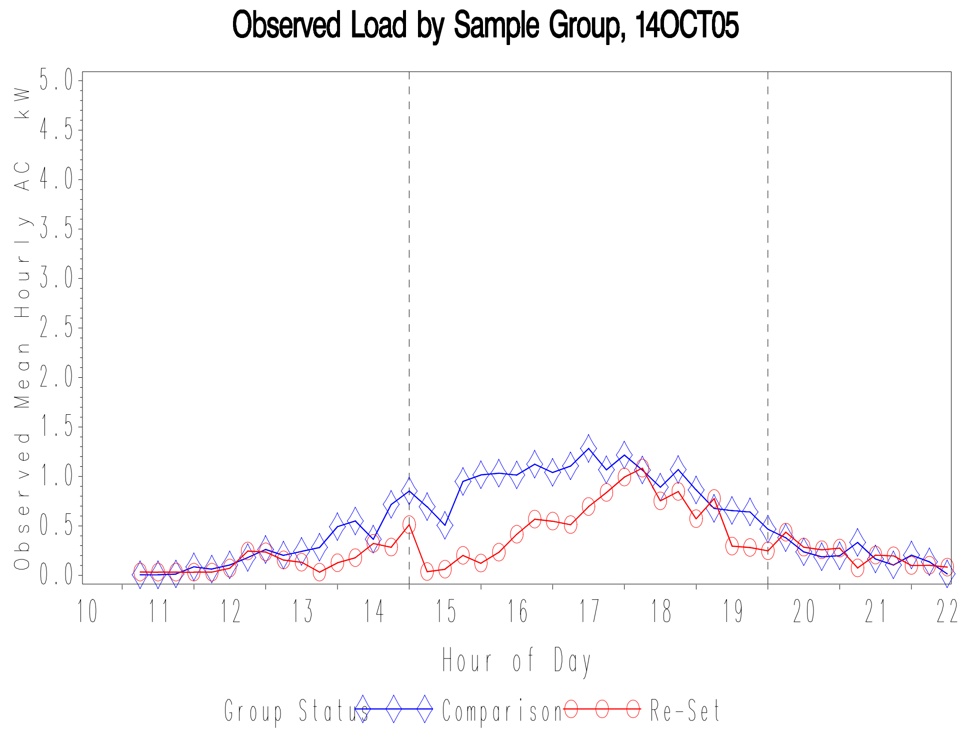

Observed Load by Sample Group, 13OCT05
Observed Mean Hourly AC kW
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Group Status Comparison Re-Set

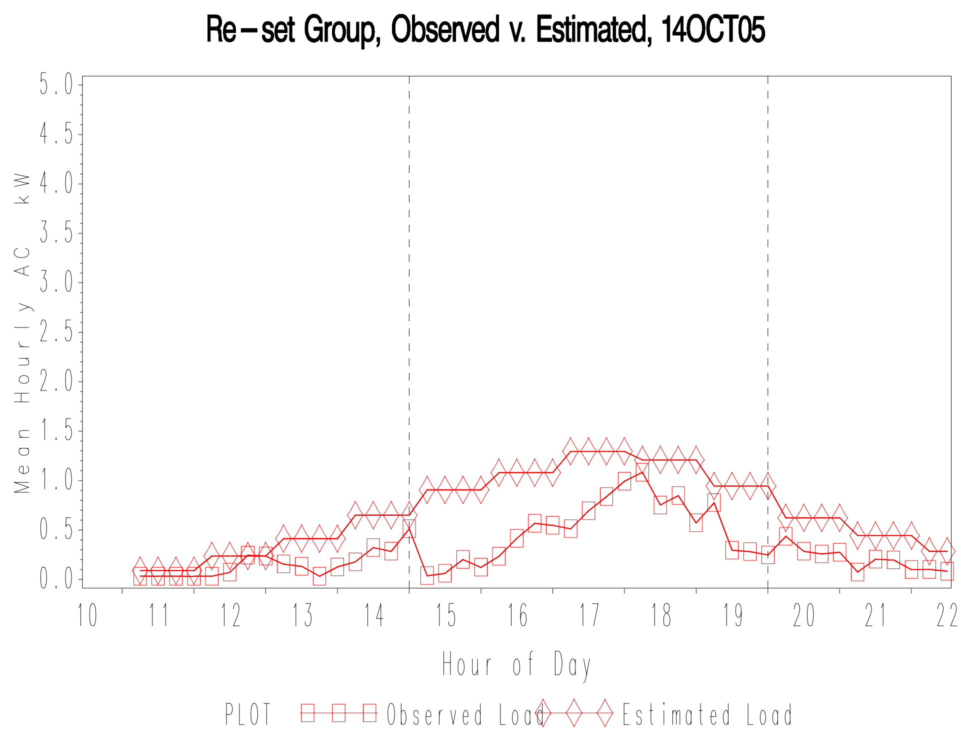

Re-set Group, Observed v. Estimated, 13OCT05
Mean Hourly AC kW
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT Observed Load Estimated Load


Comparison Group, Actuals v. Estimated, 13OCT05
Mean Hourly AC kW
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT Observed Load Estimated Load

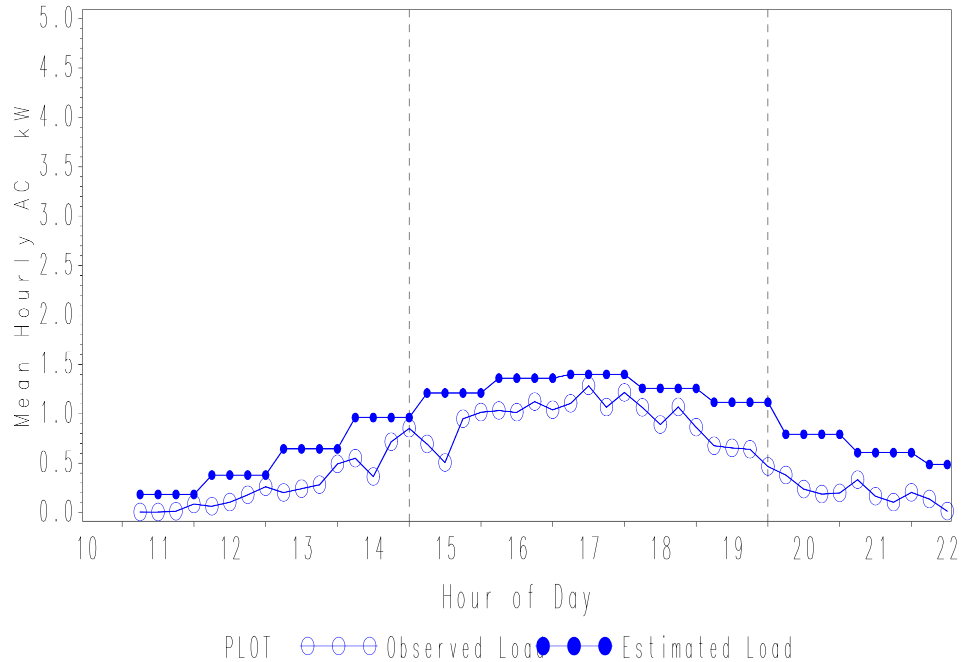

Estimated Load by Sample Group, 13OCT05
Estimated Mean Hourly AC kW
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Group Status Comparison Re-Set


Impact Estimate for 13OCT05
Mean AC Impact, kW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
-0.6
-0.8
-1.0
-1.2
-1.4
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT DD2_T Upper 90% C.I.
lower 90% C.I. Curtail_Period

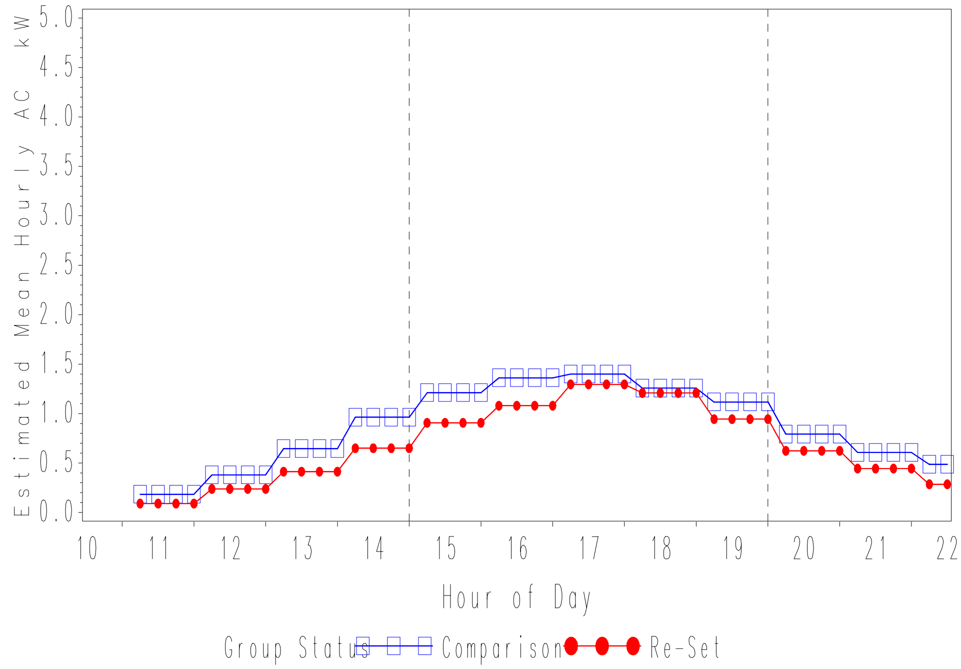

Observed Load by Sample Group, 14OCT05
Observed Mean Hourly AC kW
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Group Status
Comparison
Re-Set

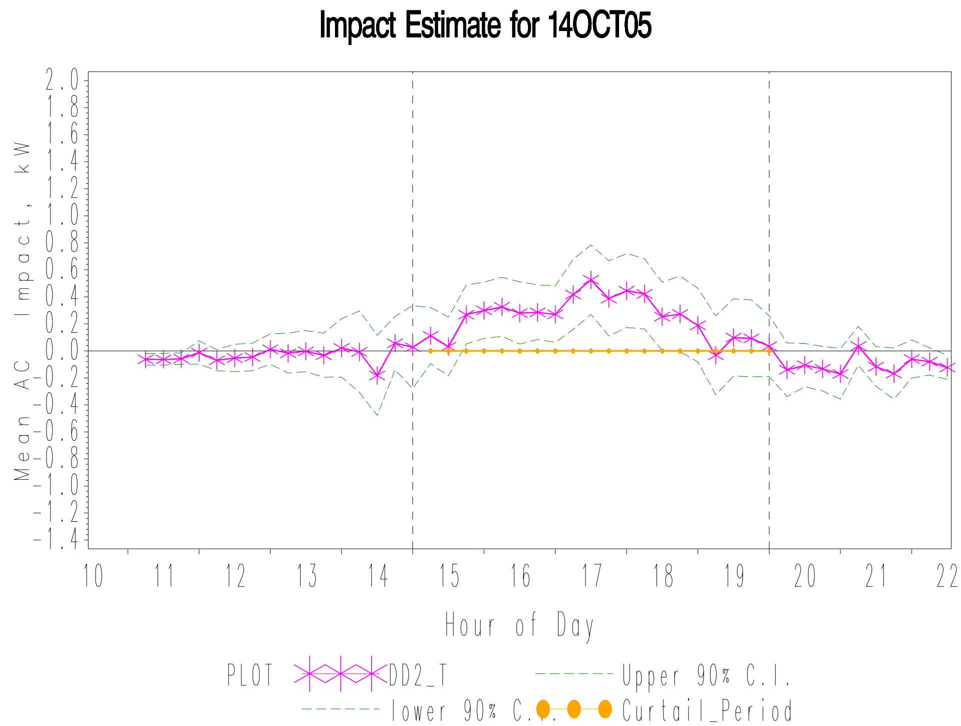

Re-set Group, Observed v. Estimated, 14OCT05
Mean Hourly AC kW
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load

Comparison Group, Actuals v. Estimated, 14OCT05



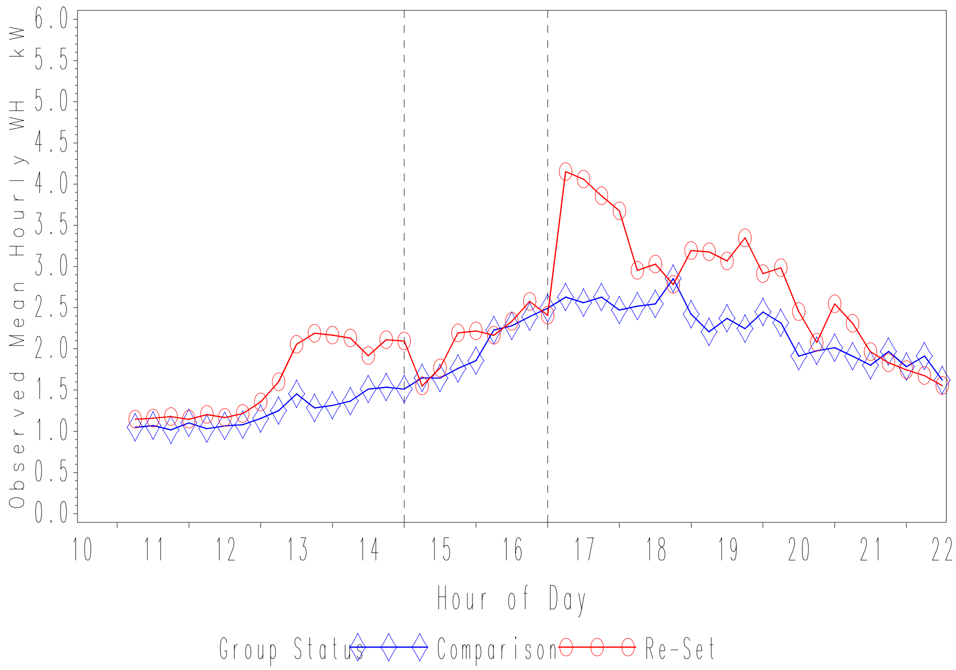
Estimated Load by Sample Group, 14OCT05



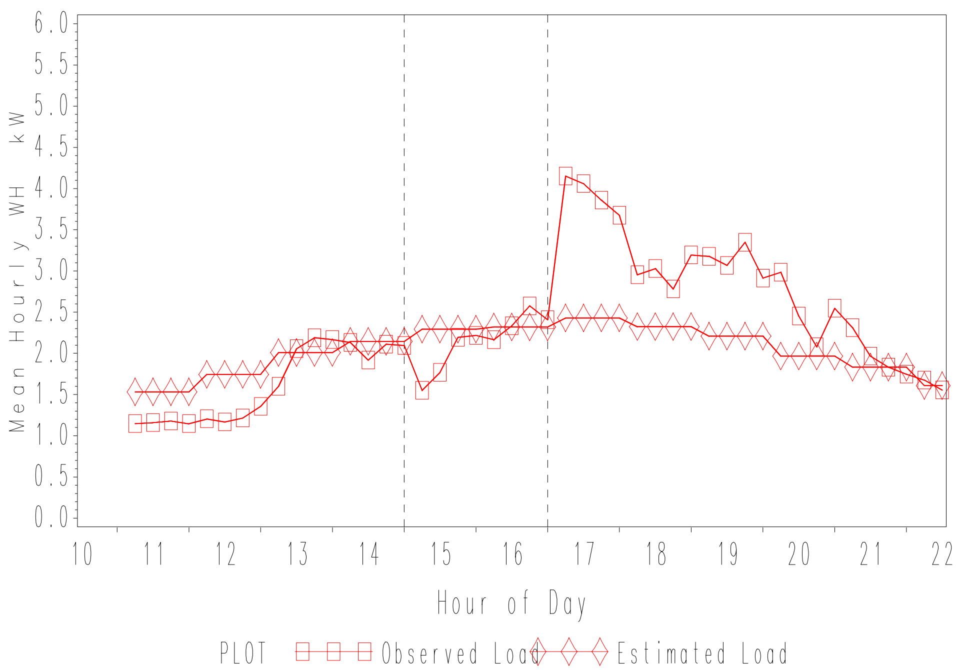

Impact Estimate for 14OCT05
Mean AC Impact, kW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
-0.6
-0.8
-1.0
-1.2
-1.4
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
DD2_T
Upper 90% C.I.
lower 90% C.I.
Curtail_Period

B WHOLE HOUSE IMPACT PLOTS

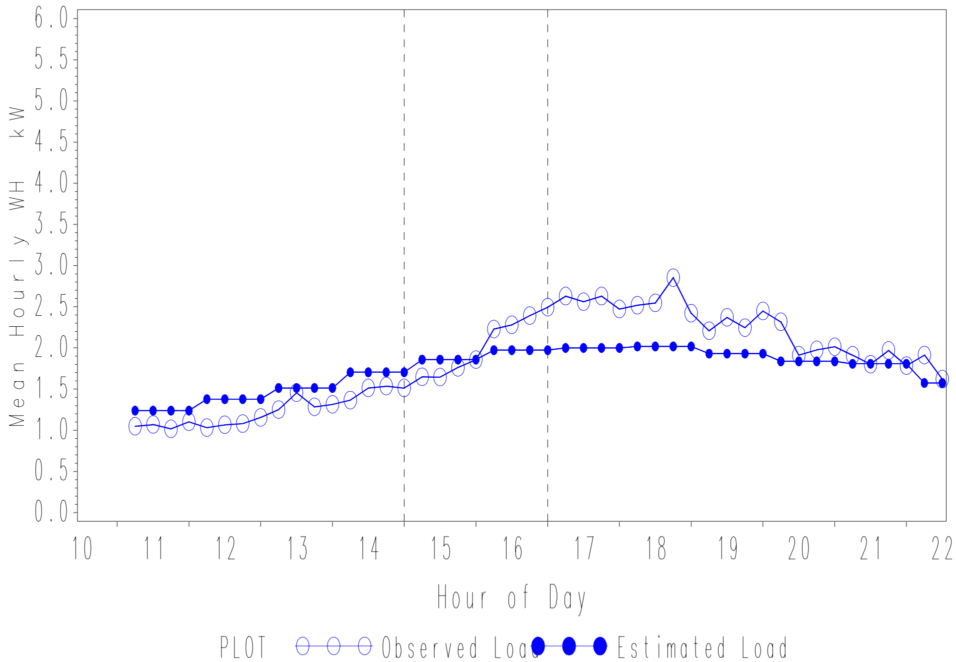
Observed Load by Sample Group, 13JUL05



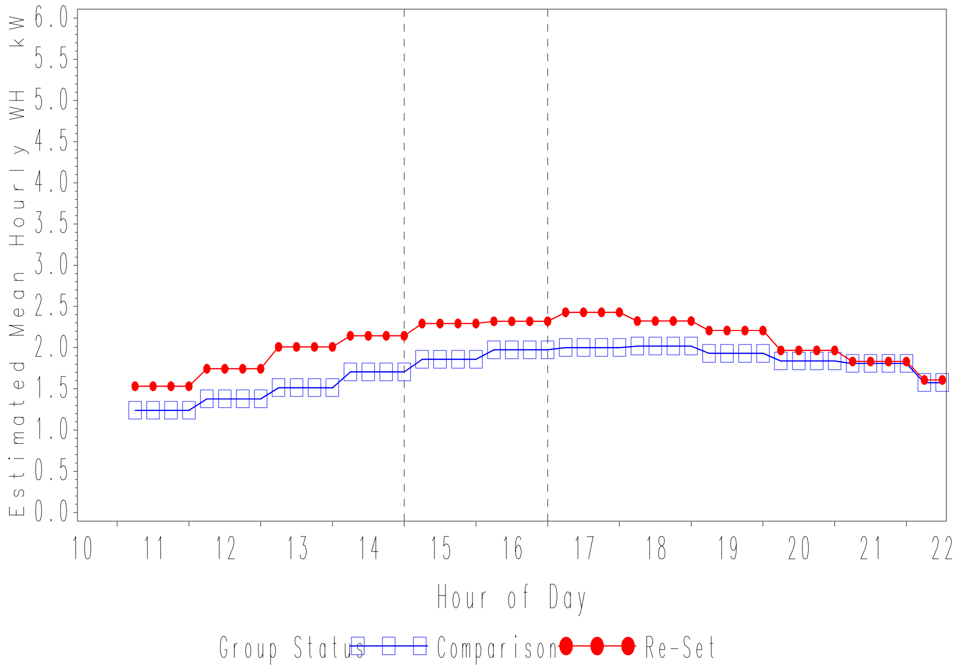
Re–set Group, Observed v. Estimated, 13JUL05



Comparison Group, Actuals v. Estimated, 13JUL05

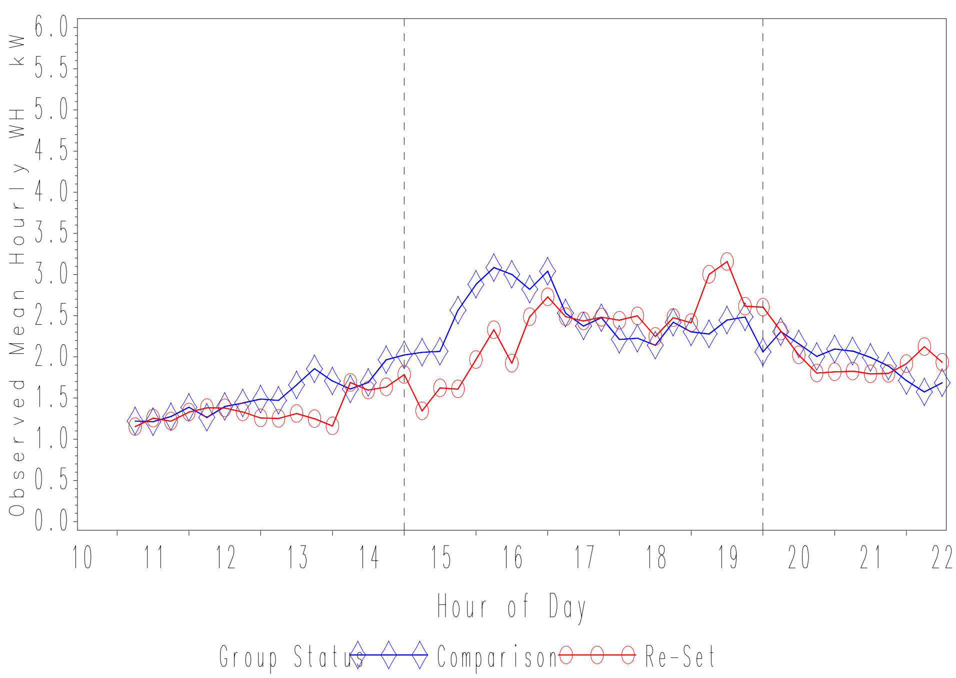


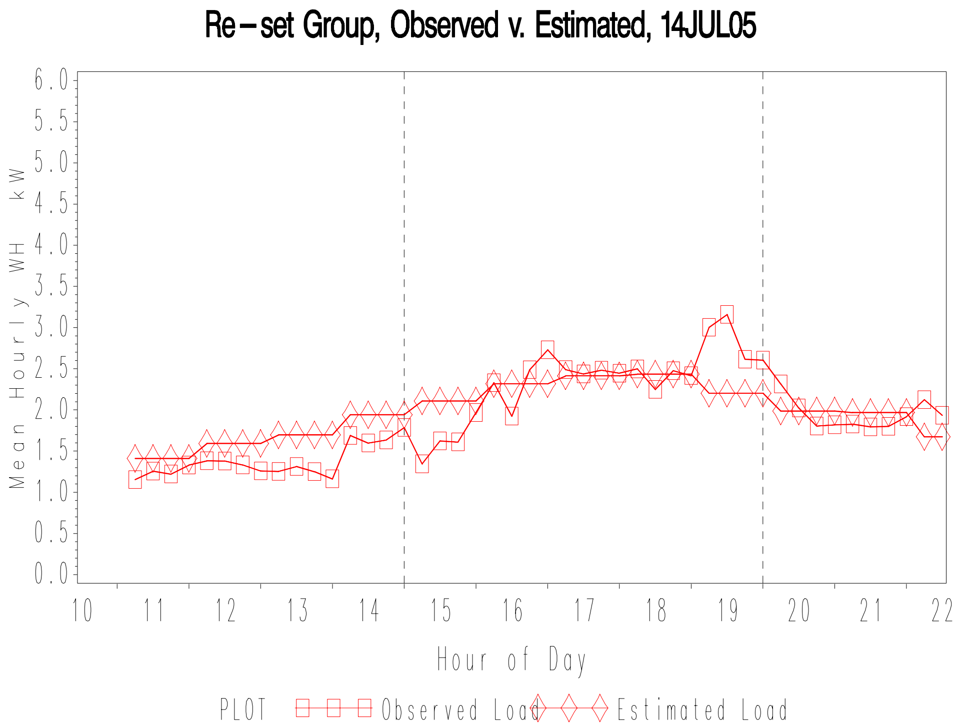
Estimated Load by Sample Group, 13JUL05

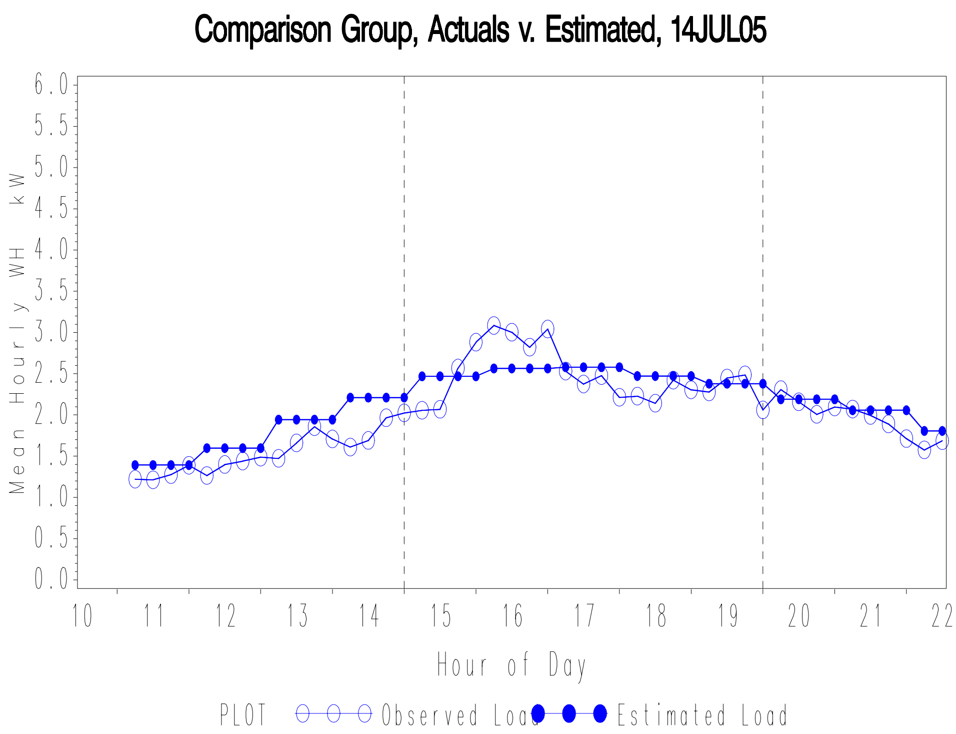


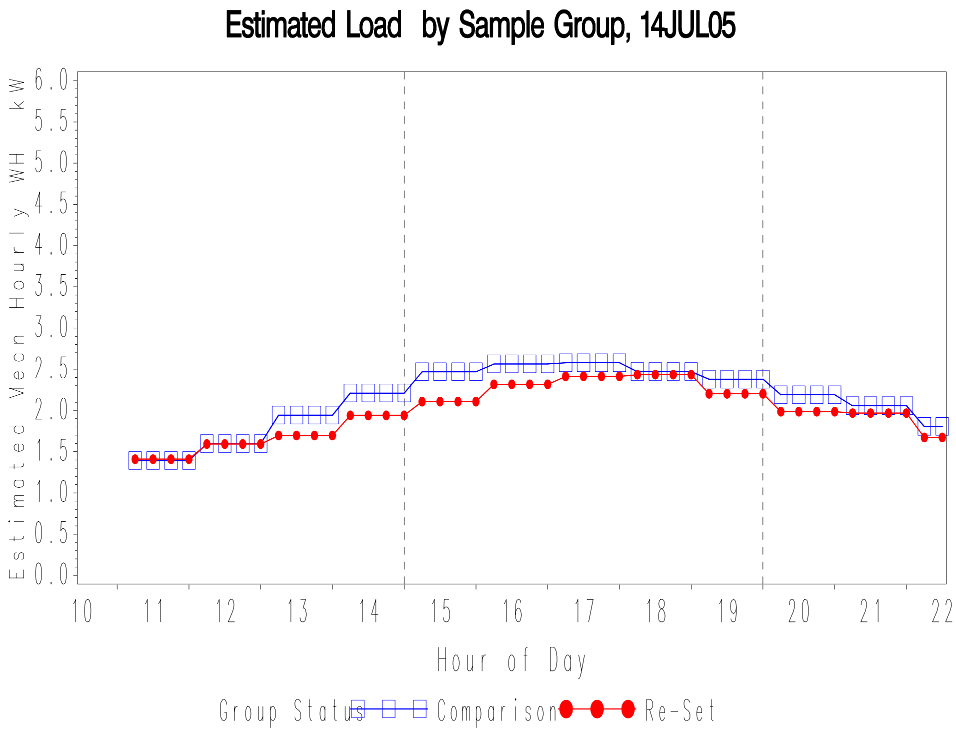
Impact Estimate for 13JUL05

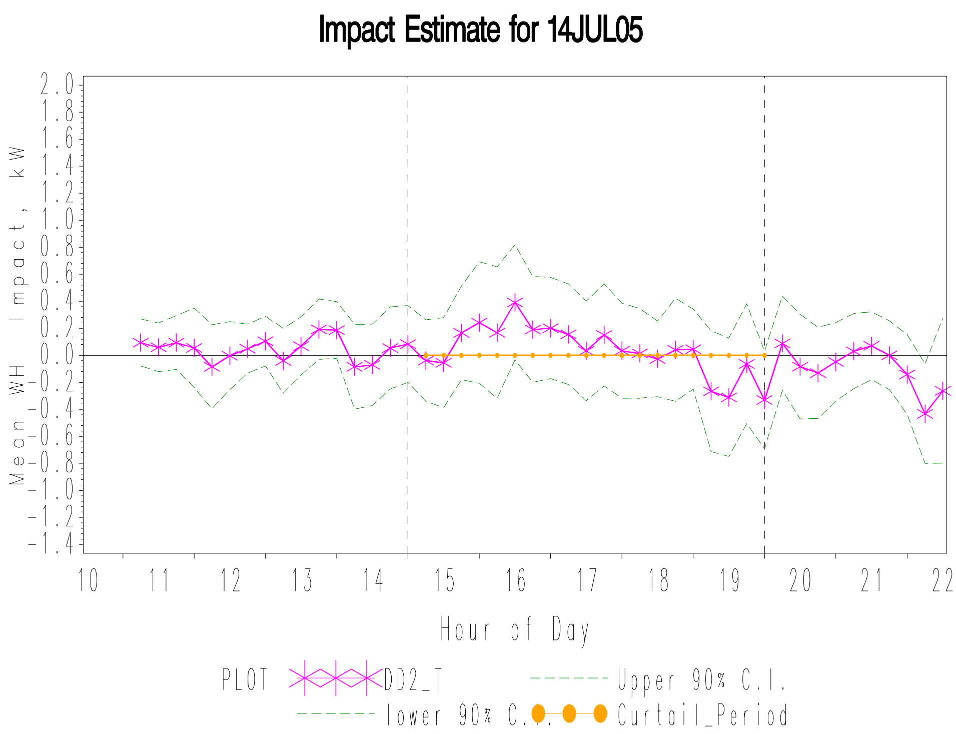
Observed Load by Sample Group, 14JUL05



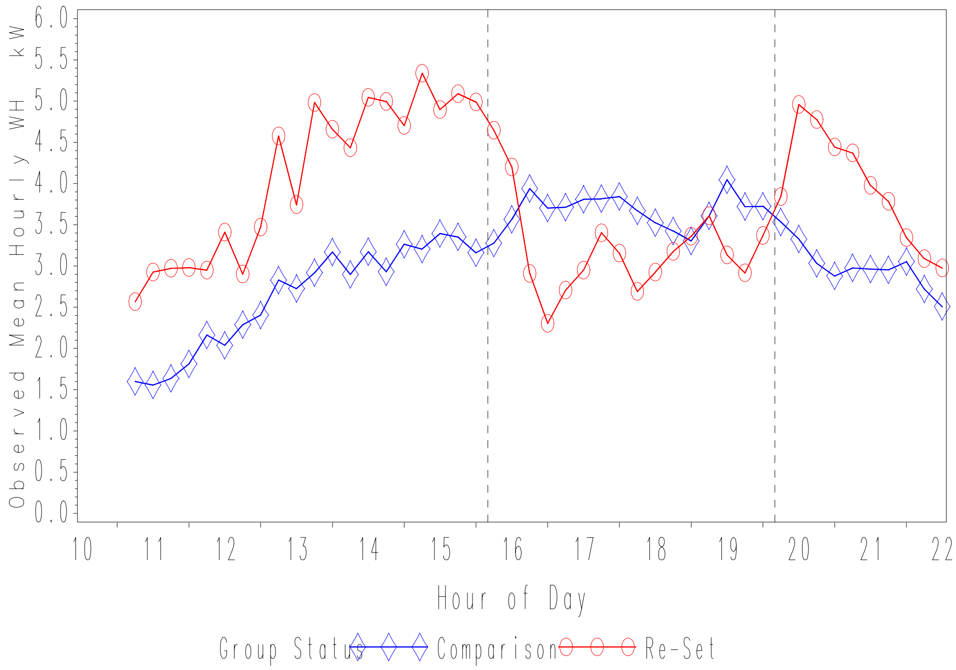

Re-set Group, Observed v. Estimated, 14JUL05
Mean Hourly WH kW
6.0
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT Observed Load Estimated Load


Comparison Group, Actuals v. Estimated, 14JUL05
Mean Hourly WH kW
6.0
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT Observed Load Estimated Load

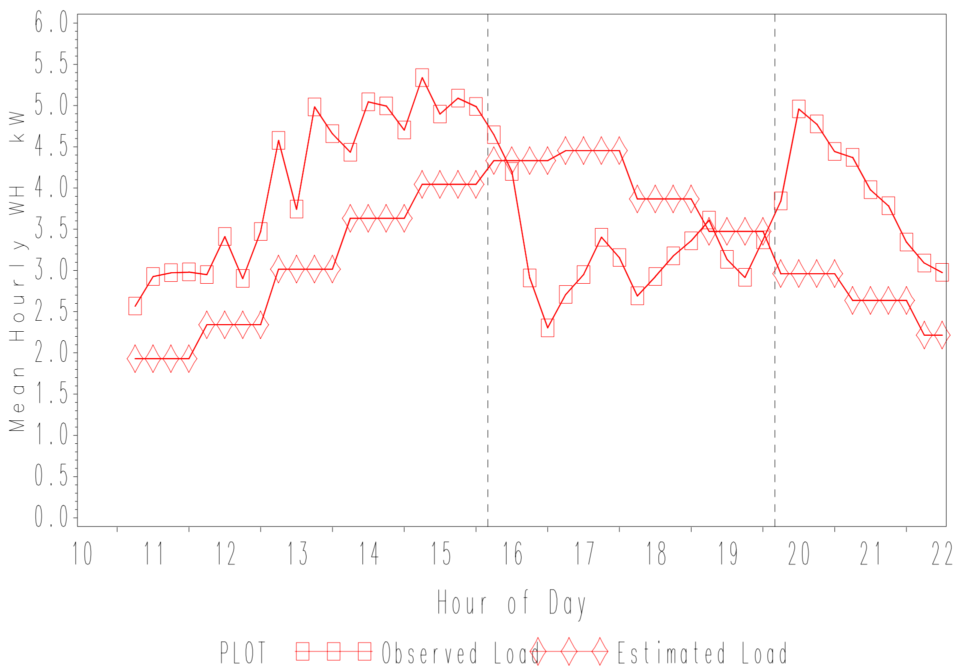

Estimated Load by Sample Group, 14JUL05
Estimated Mean Hourly WH kW
6.0
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Group Status
Comparison
Re-Set

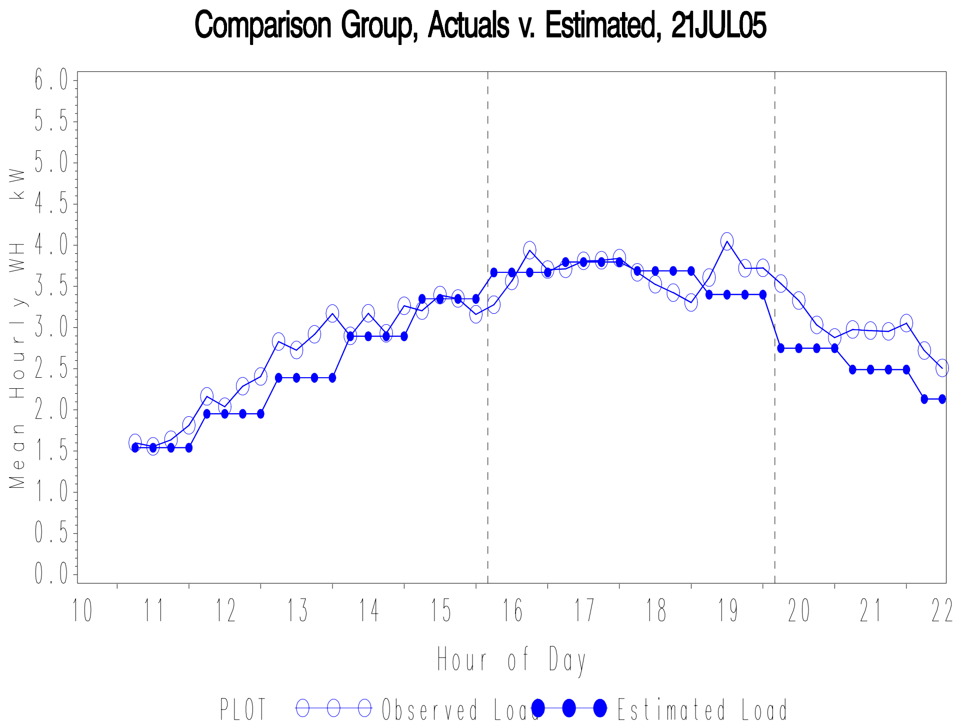

Impact Estimate for 14JUL05
Mean WH Impact, kW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
-0.6
-0.8
-1.0
-1.2
-1.4
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
DD2_T
Upper 90% C.I.
lower 90% C.I.
Curtail_Period

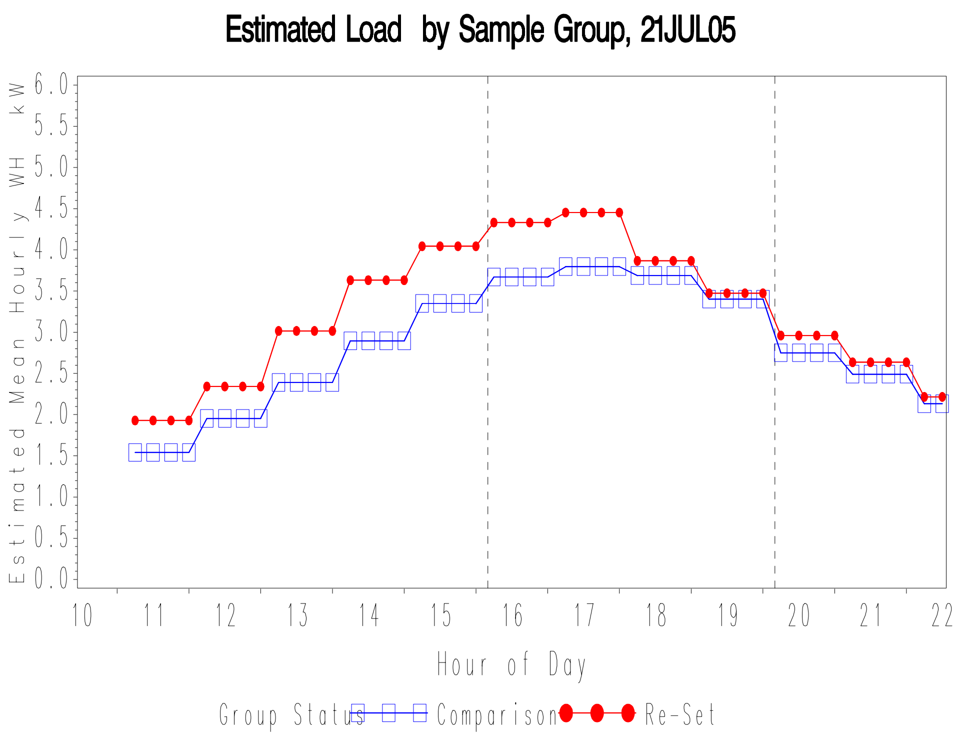
Observed Load by Sample Group, 21JUL05

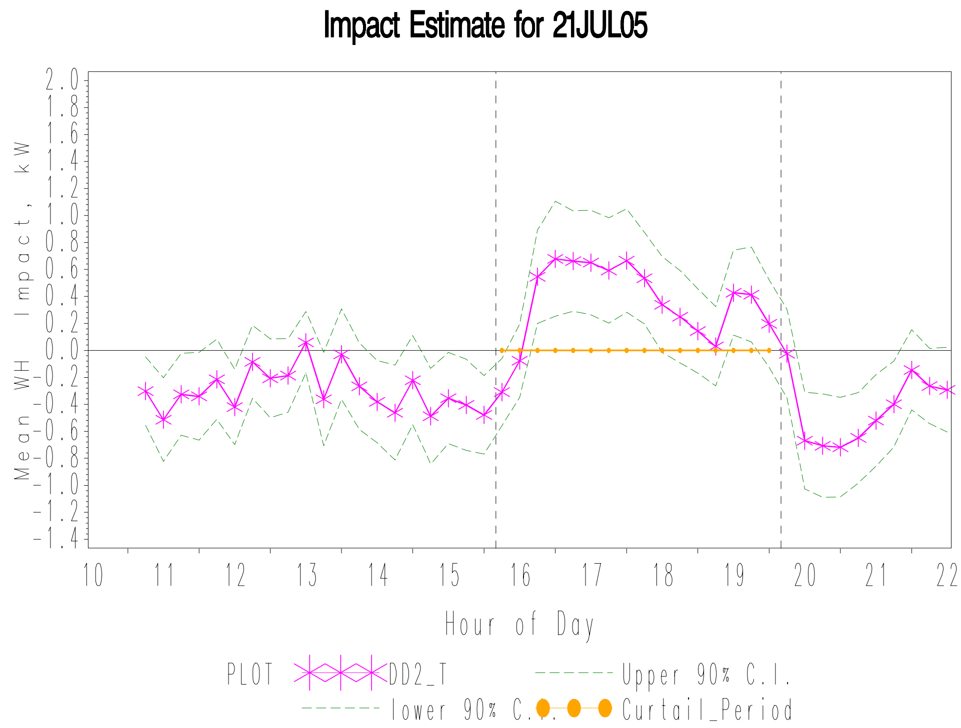


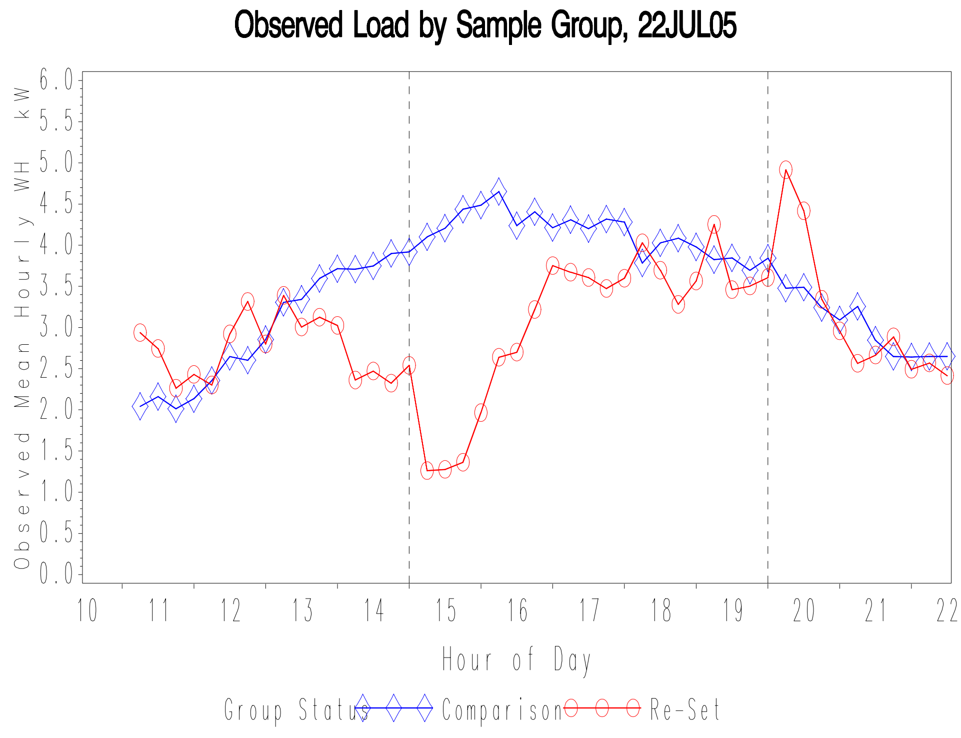
Re-set Group, Observed v. Estimated, 21JUL05

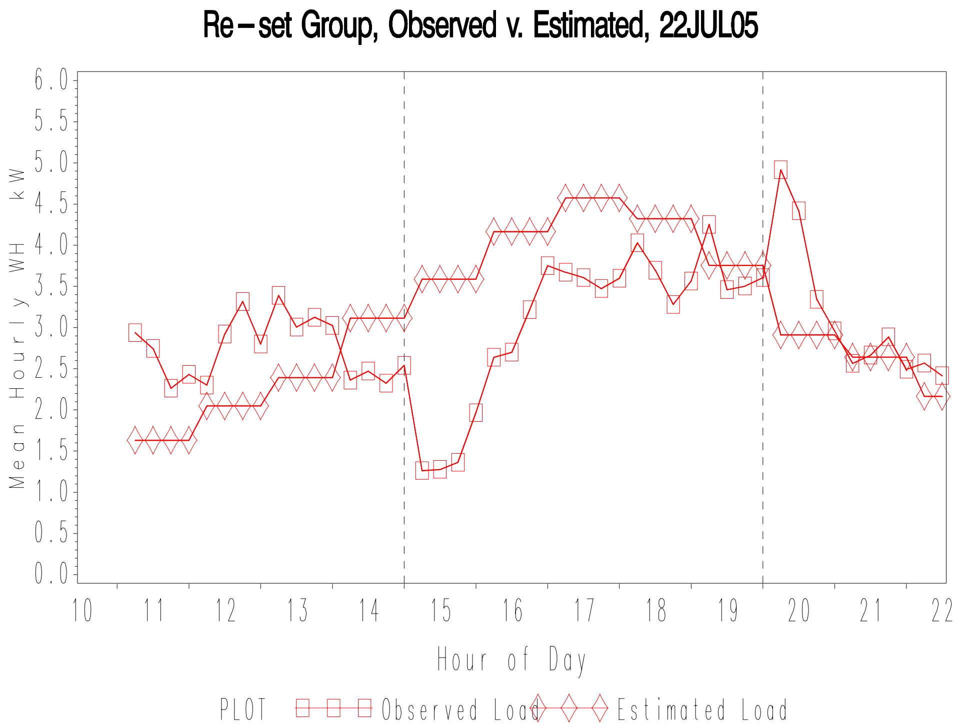


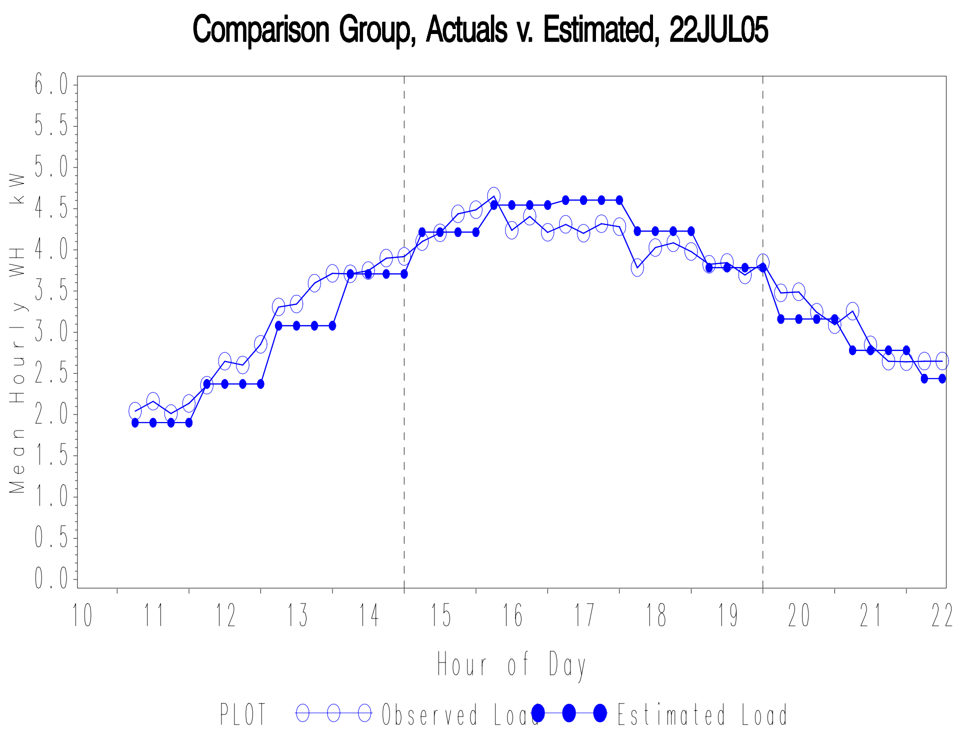

Comparison Group, Actuals v. Estimated, 21JUL05
Mean Hourly WH kW
6.0
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10
11
12
13
14
15
16
17
18
19
20
21
22
Hour of Day
PLOT
Observed Load
Estimated Load

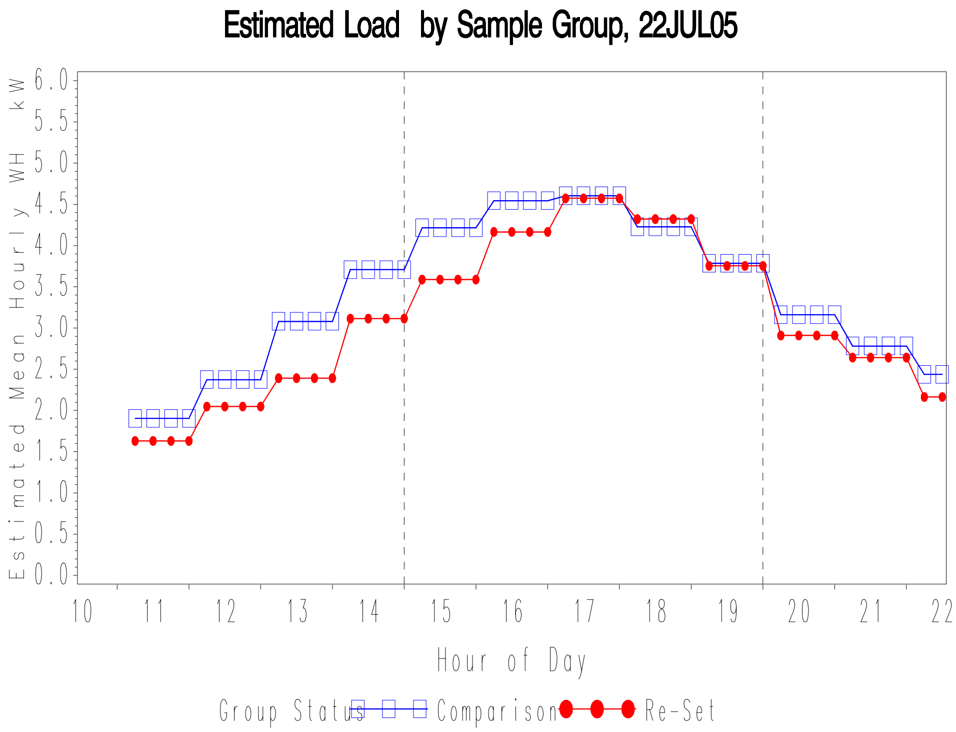

Estimated Load by Sample Group, 21JUL05
Estimated Mean Hourly WH kW
6.0
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10
11
12
13
14
15
16
17
18
19
20
21
22
Hour of Day
Group Status
Comparison
Re-Set

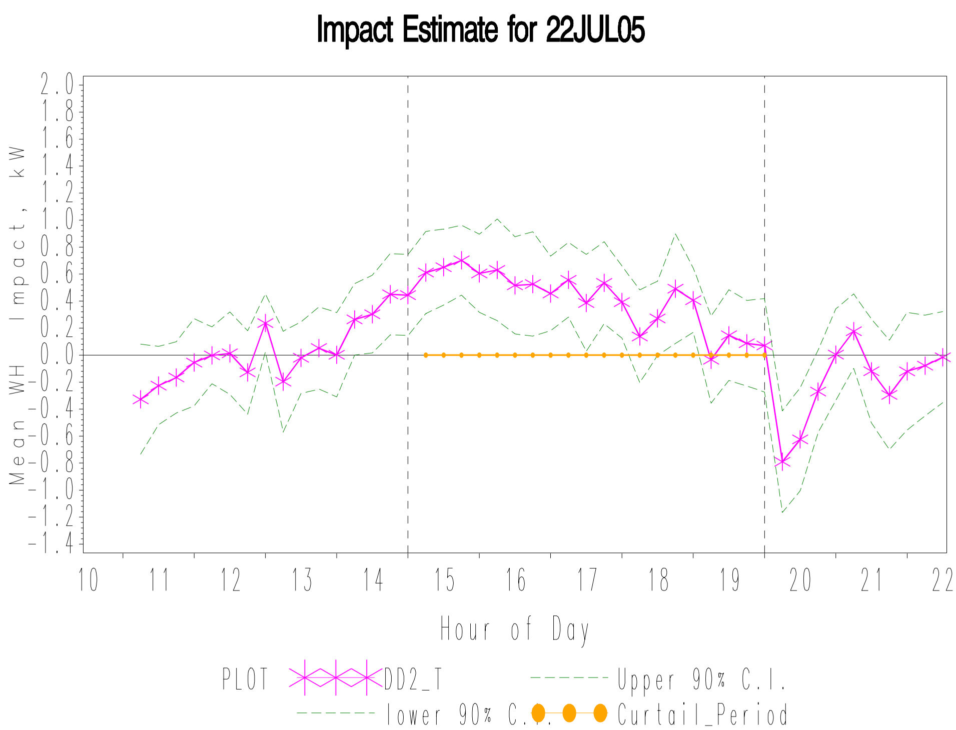

Impact Estimate for 21JUL05
Mean WH Impact, kW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
-0.6
-0.8
-1.0
-1.2
-1.4
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT DD2_T
Upper 90% C.I.
lower 90% C.I.
Curtail_Period

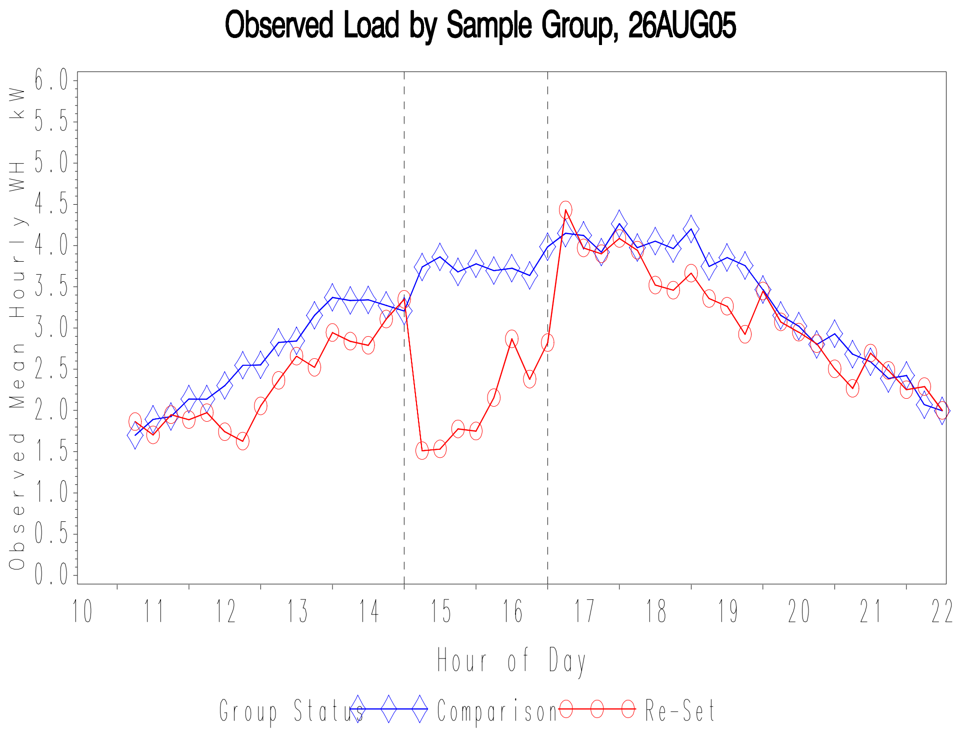

Observed Load by Sample Group, 22JUL05
Observed Mean Hourly WH kW
6.0
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Group Status
Comparison
Re-Set

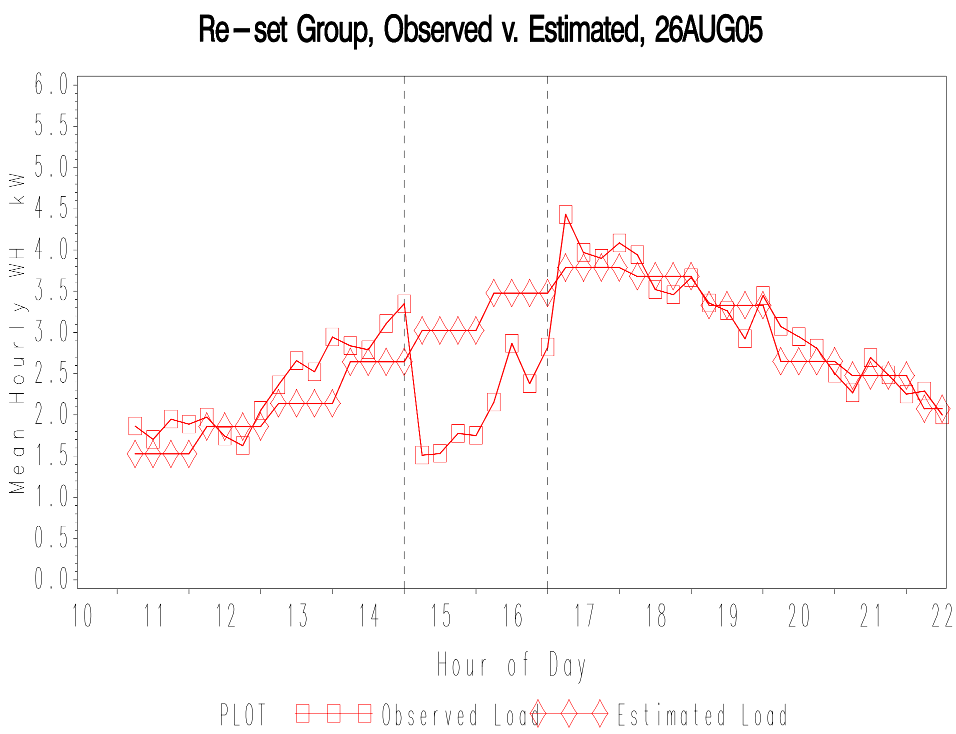

Re-set Group, Observed v. Estimated, 22JUL05
Mean Hourly WH kW
6.0
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT Observed Load Estimated Load


Comparison Group, Actuals v. Estimated, 22JUL05
Mean Hourly WH kW
6.0
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT Observed Load Estimated Load

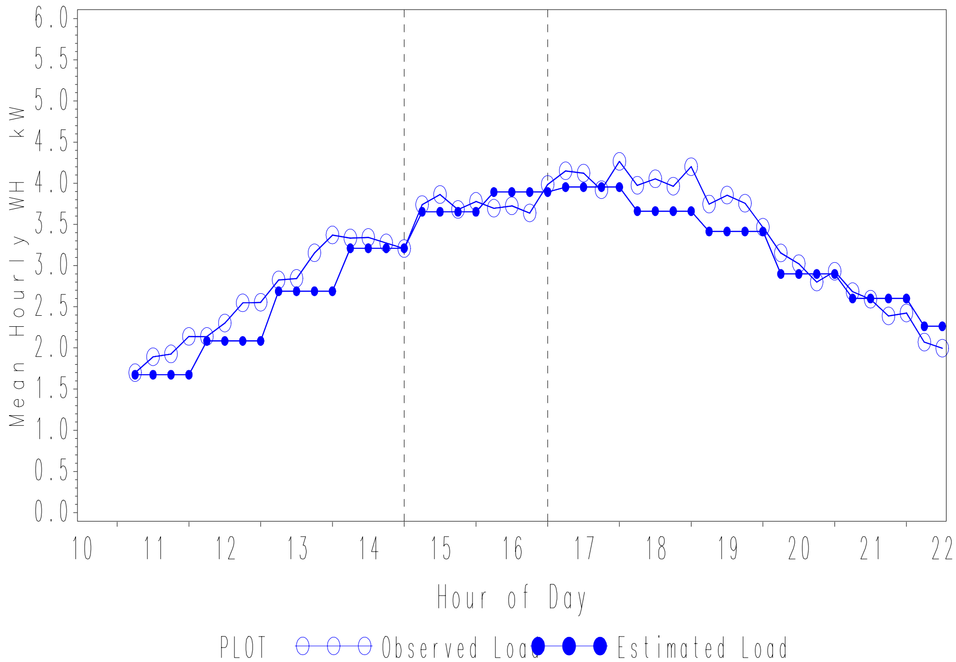

Estimated Load by Sample Group, 22JUL05
Estimated Mean Hourly WH kW
6.0
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Group Status Comparison Re-Set


Impact Estimate for 22JUL05
Mean WH Impact, kW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
-0.6
-0.8
-1.0
-1.2
-1.4
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT DD2_T Upper 90% C.I.
lower 90% C.I. Curtail_Period

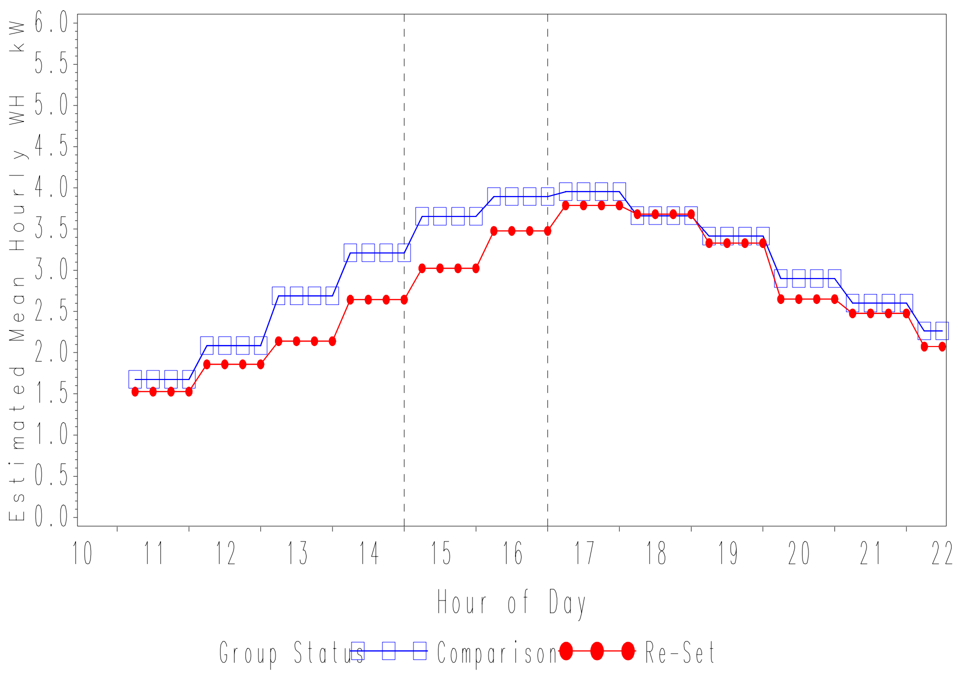

Observed Load by Sample Group, 26AUG05
Observed Mean Hourly WH kW
0.0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
5.0
5.5
6.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Group Status
Comparison
Re-Set


Re-set Group, Observed v. Estimated, 26AUG05
Mean Hourly WH kW
0.0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
5.0
5.5
6.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load

Comparison Group, Actuals v. Estimated, 26AUG05

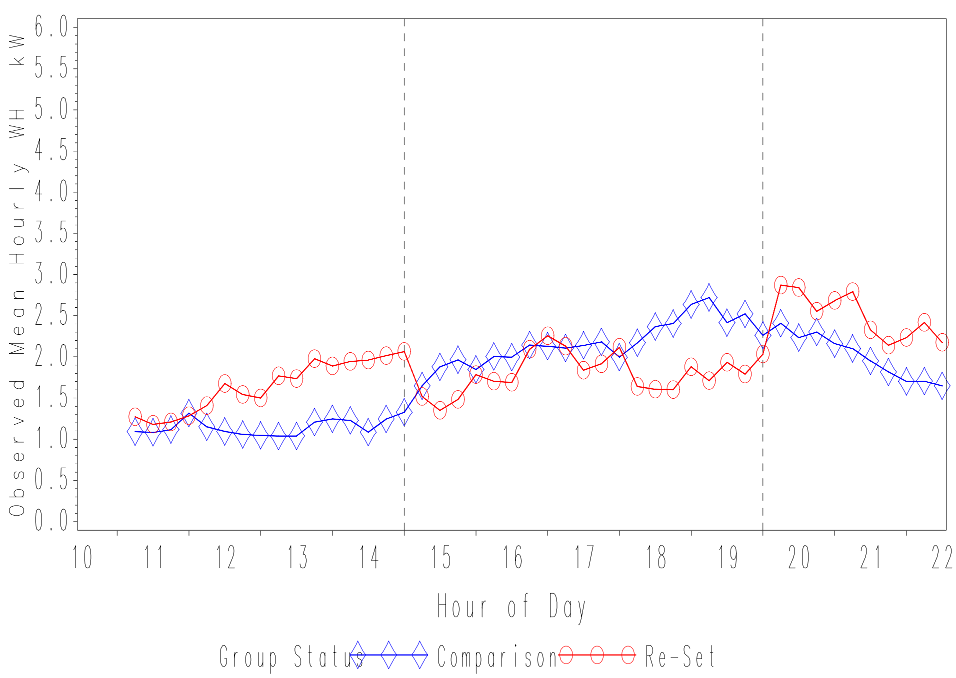


Estimated Load by Sample Group, 26AUG05

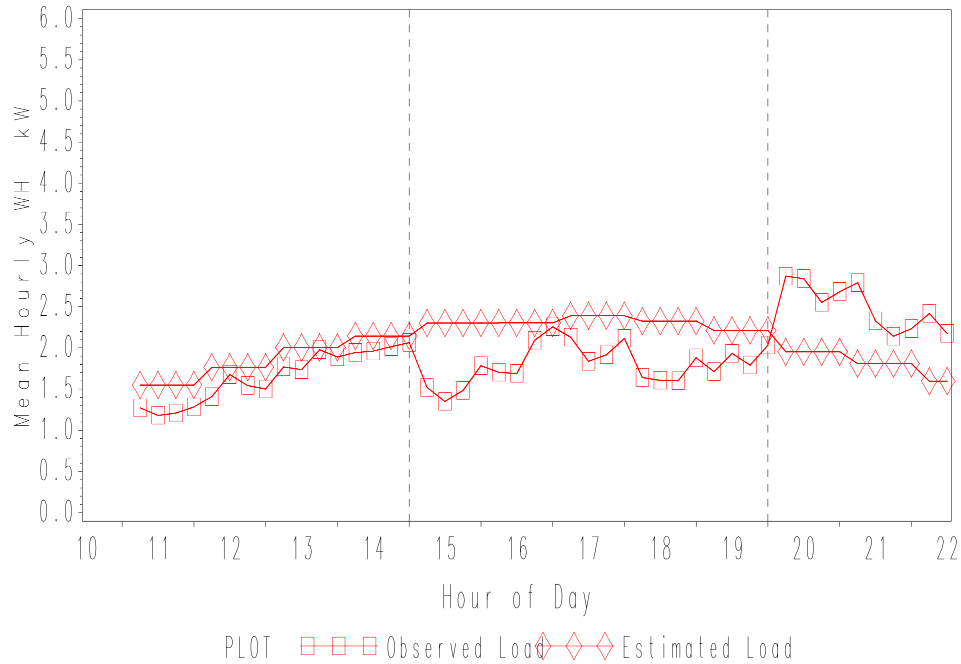


Impact Estimate for 26AUG05

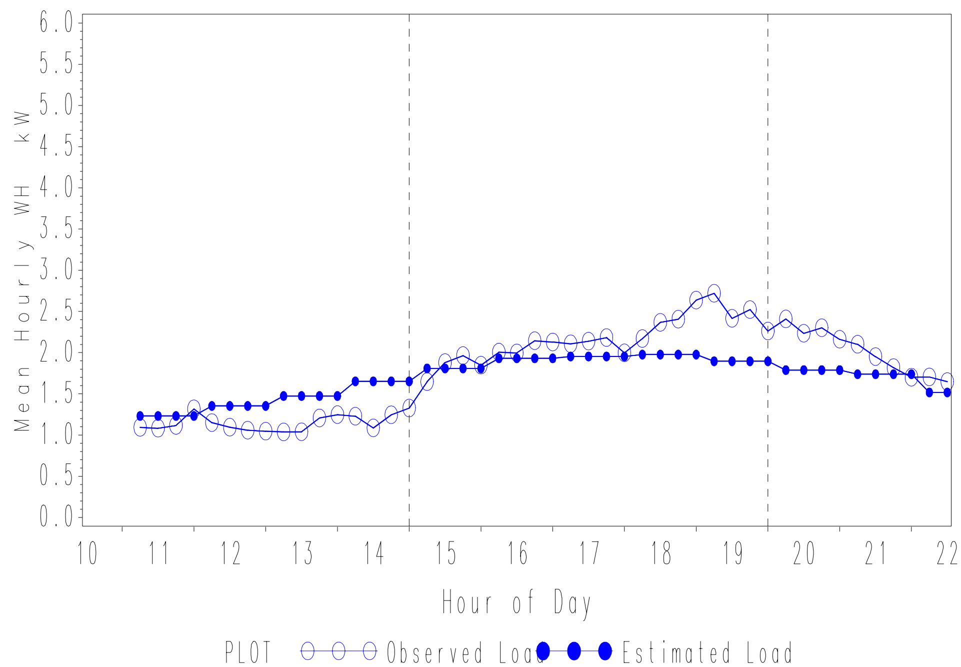
Observed Load by Sample Group, 28SEP05

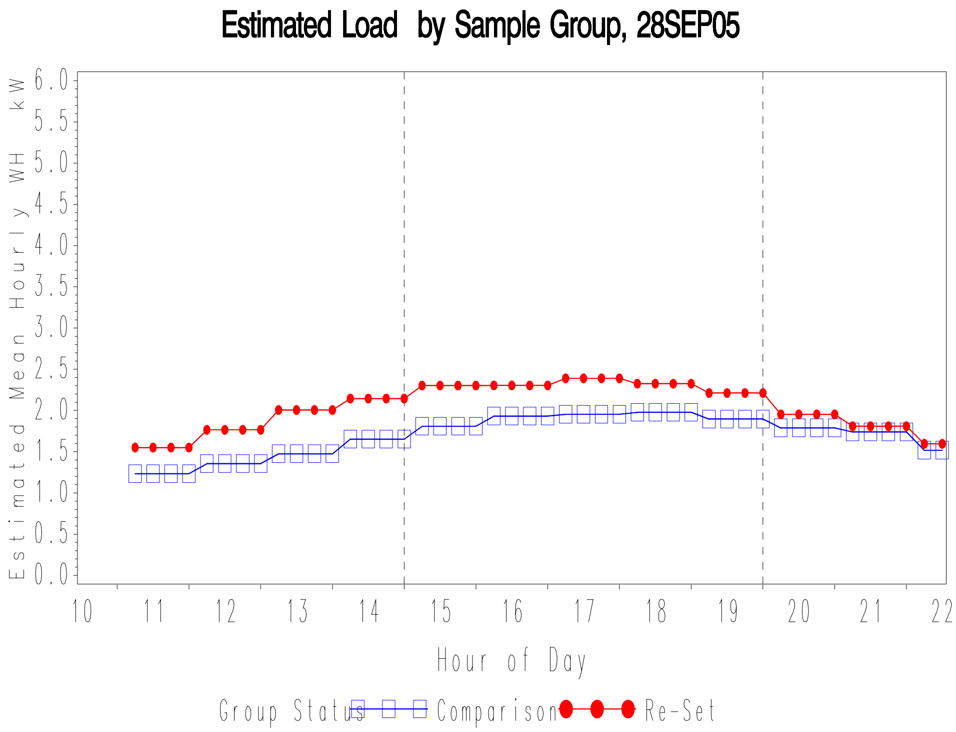


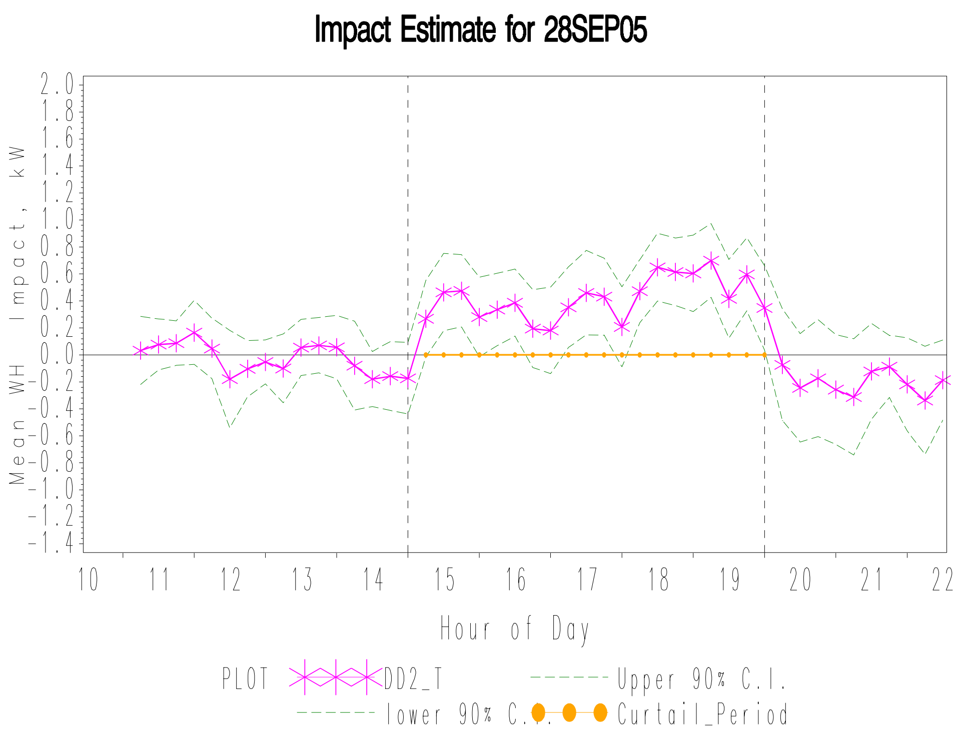
Re−set Group, Observed v. Estimated, 28SEP05



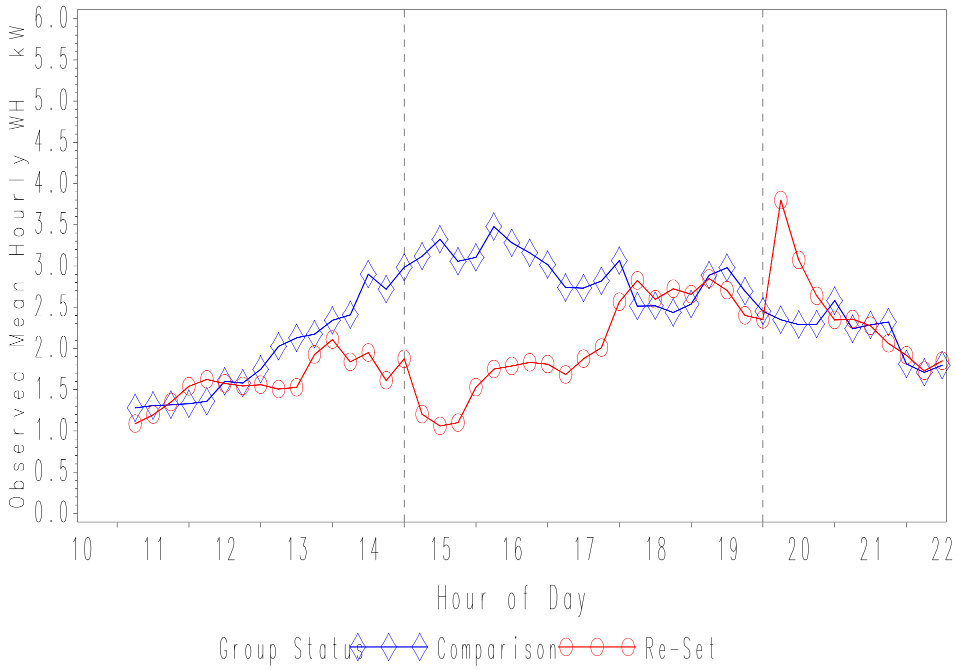
Comparison Group, Actuals v. Estimated, 28SEP05



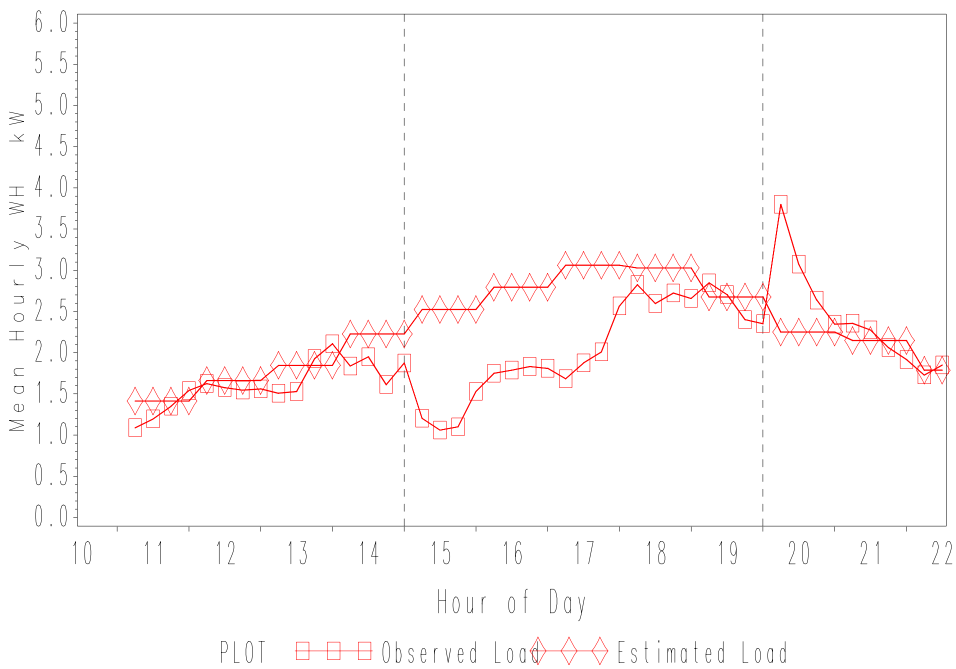

Estimated Load by Sample Group, 28SEP05
Estimated Mean Hourly WH kW
6.0
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Group Status Comparison Re-Set

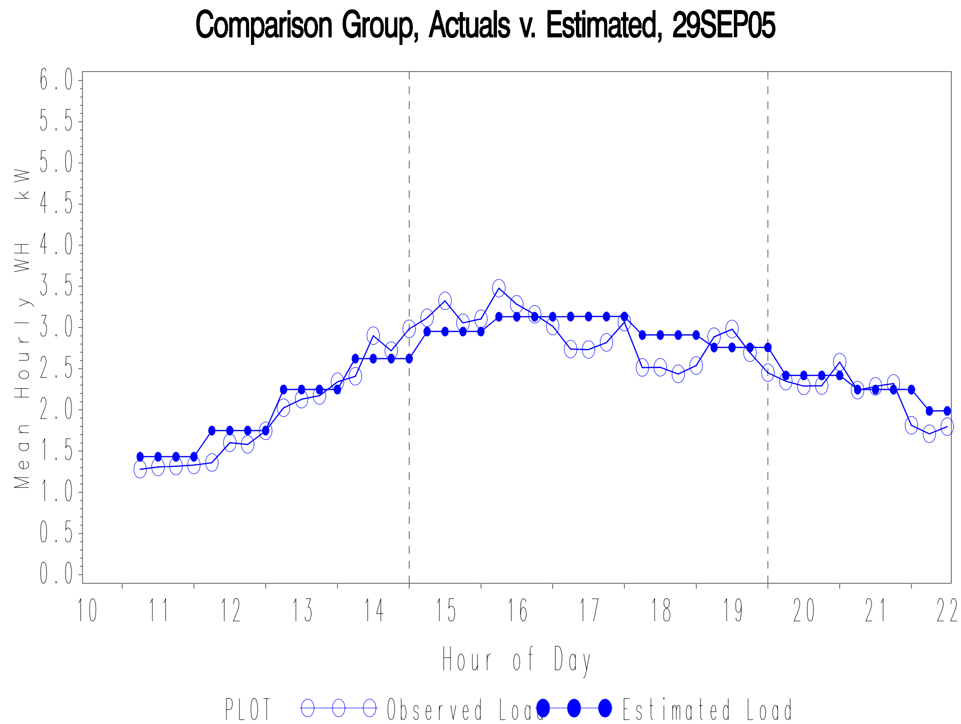

Impact Estimate for 28SEP05
Mean WH Impact, kW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
-0.6
-0.8
-1.0
-1.2
-1.4
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT DD2_T Upper 90% C.I.
lower 90% C.I. Curtail_Period

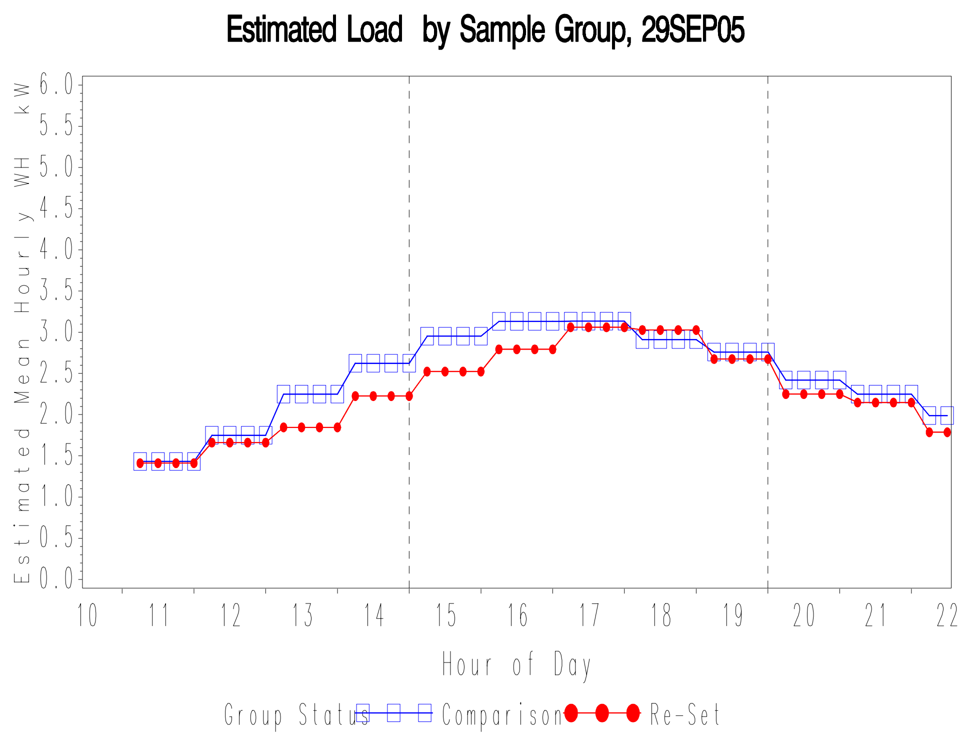
Observed Load by Sample Group, 29SEP05

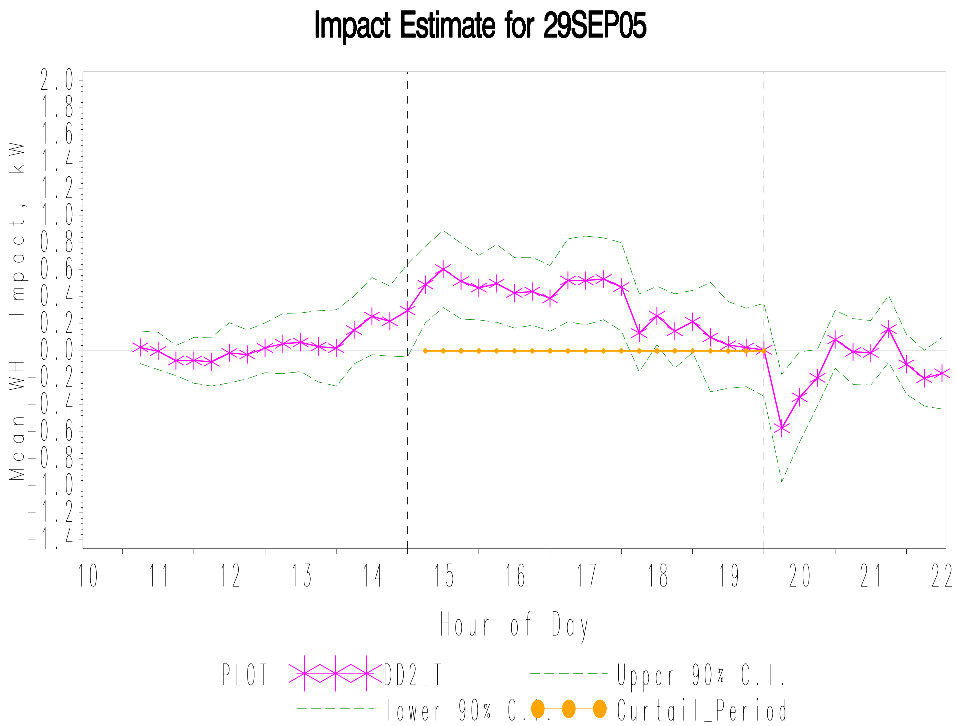


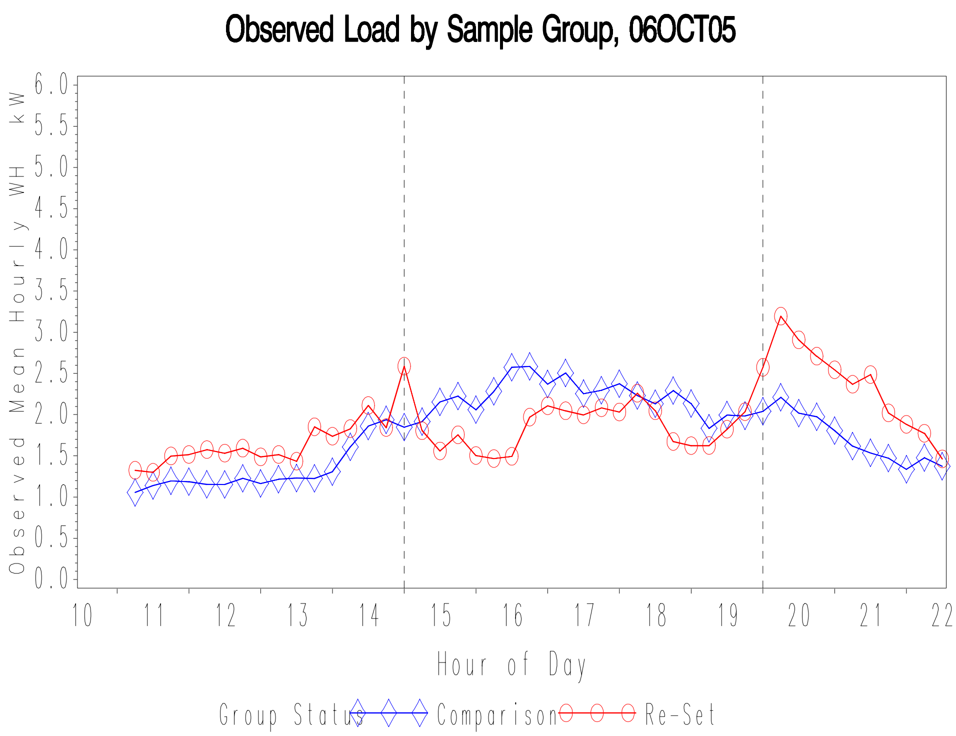
Re-set Group, Observed v. Estimated, 29SEP05



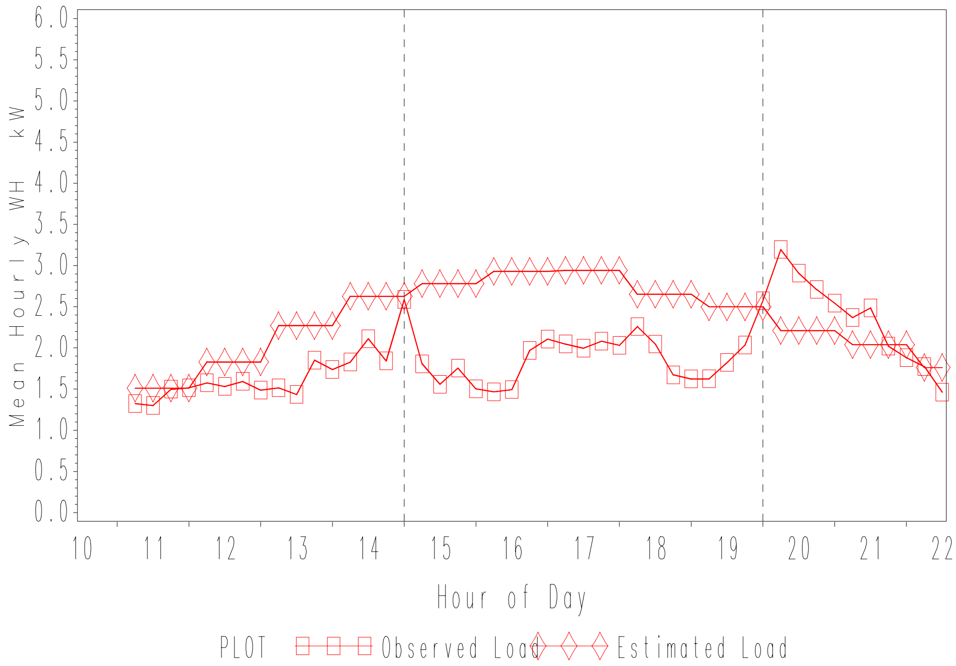

Comparison Group, Actuals v. Estimated, 29SEP05
Mean Hourly WH kW
6.0
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load


Estimated Load by Sample Group, 29SEP05
Estimated Mean Hourly WH kW
6.0
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Group Status
Comparison
Re-Set

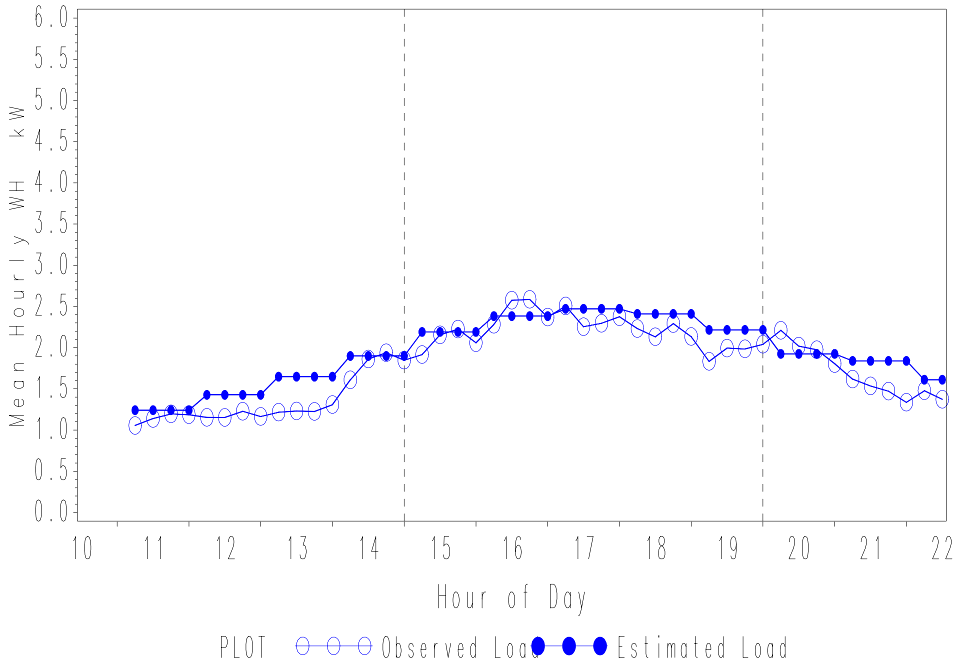

Impact Estimate for 29SEP05
Mean WH Impact, kW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
-0.6
-0.8
-1.0
-1.2
-1.4
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
DD2_T
Upper 90% C.I.
lower 90% C.I.
Curtail_Period


Observed Load by Sample Group, 06OCT05
Observed Mean Hourly WH kW
6.0
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Group Status
Comparison
Re-Set

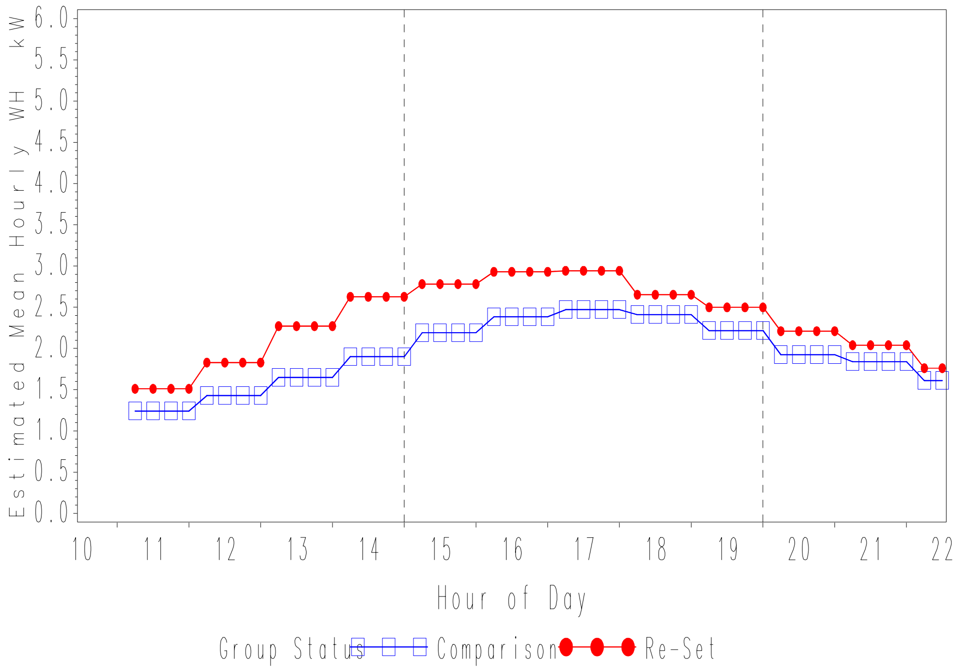
Re–set Group, Observed v. Estimated, 06OCT05



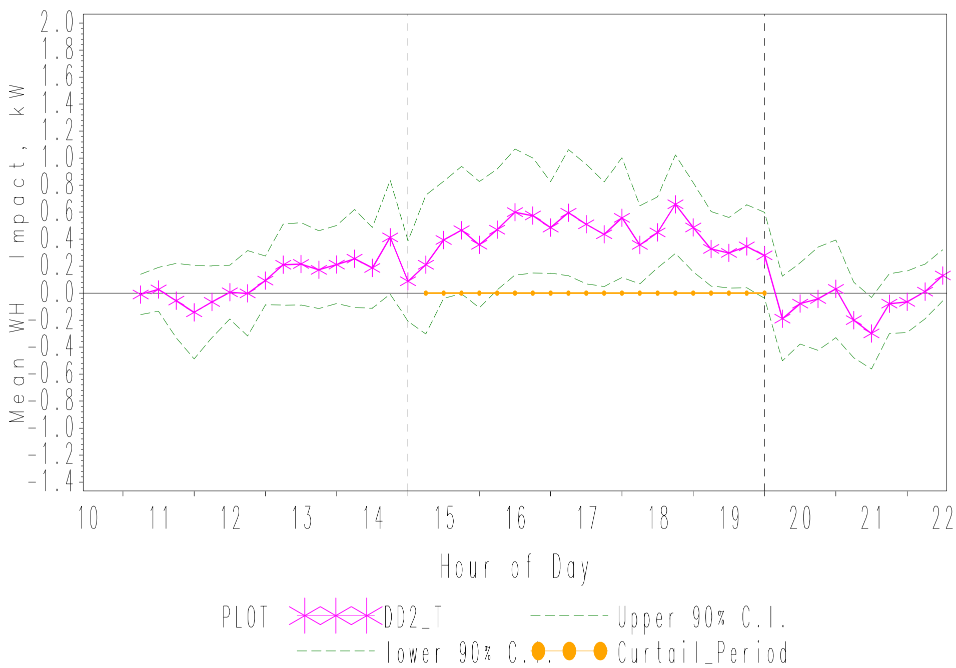
Comparison Group, Actuals v. Estimated, 06OCT05

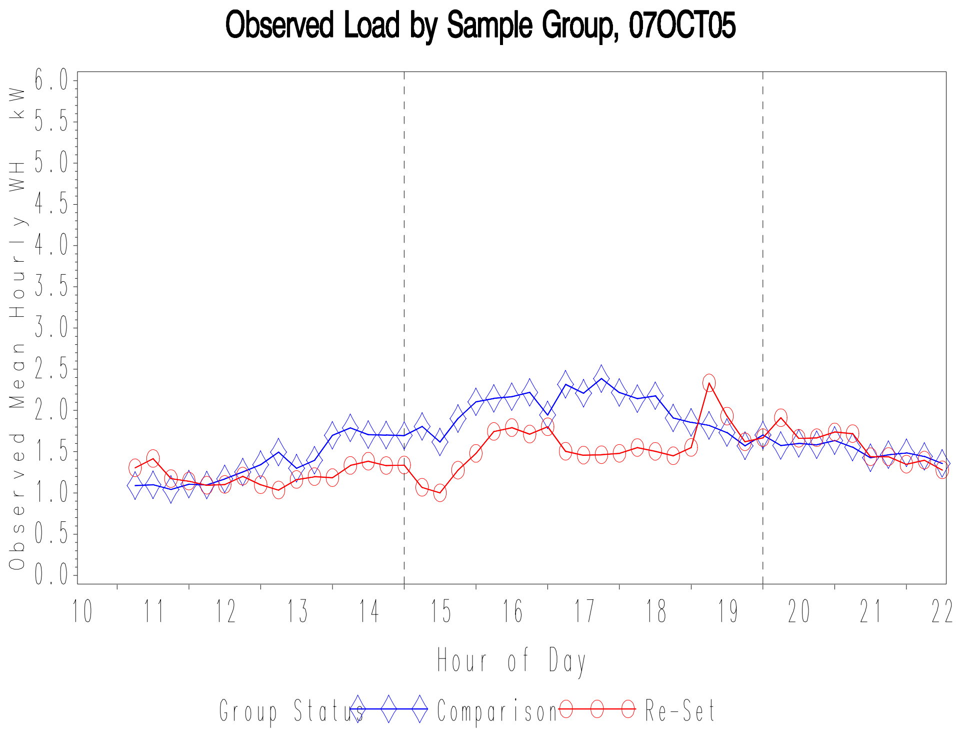


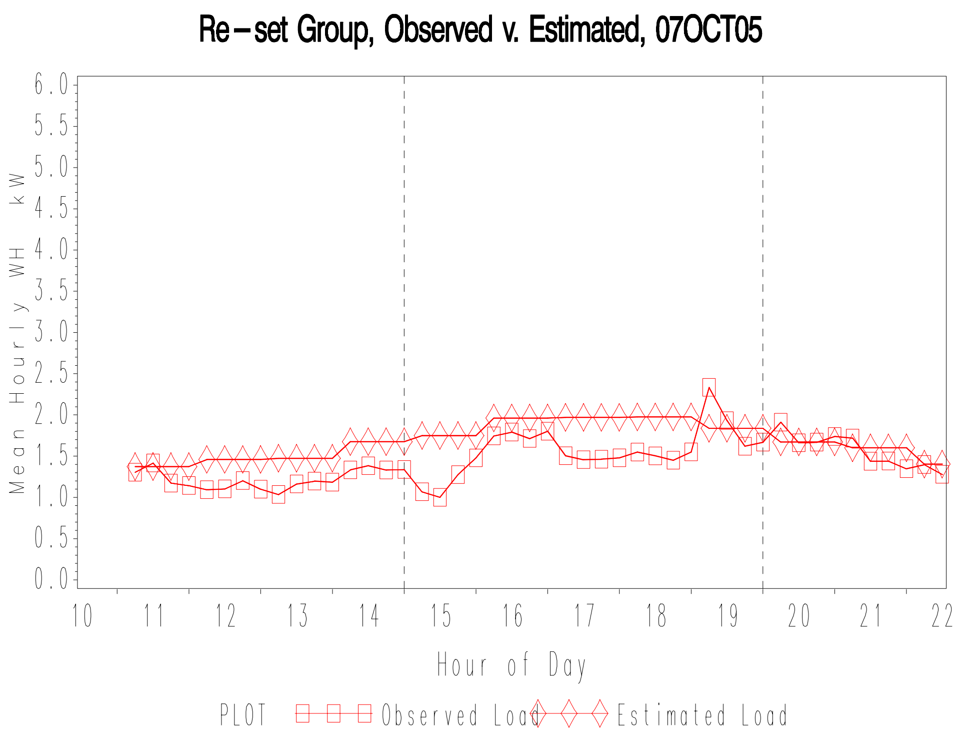
Estimated Load by Sample Group, 06OCT05



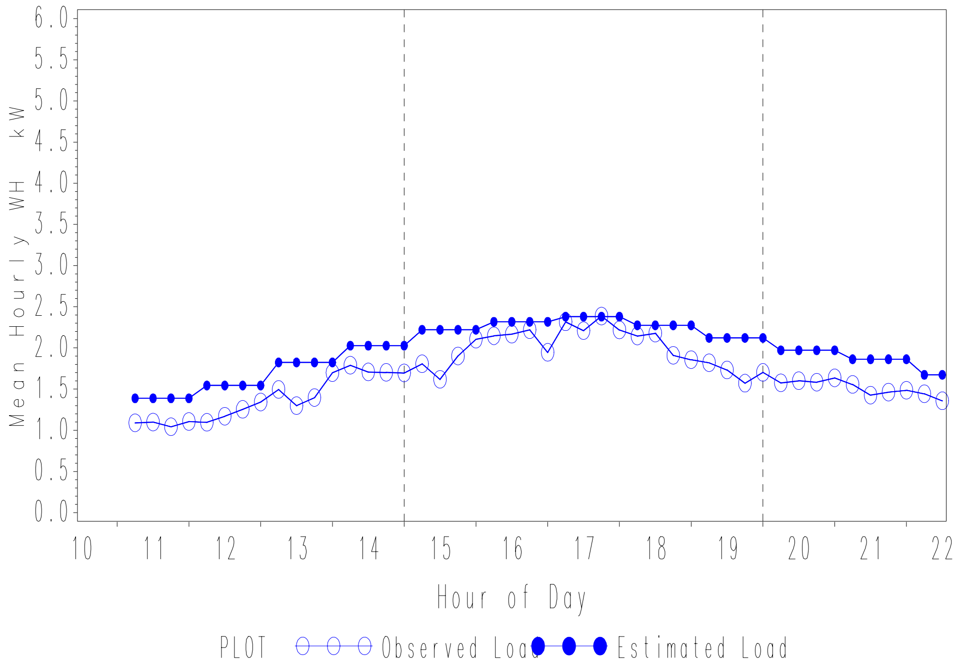
Impact Estimate for 06OCT05



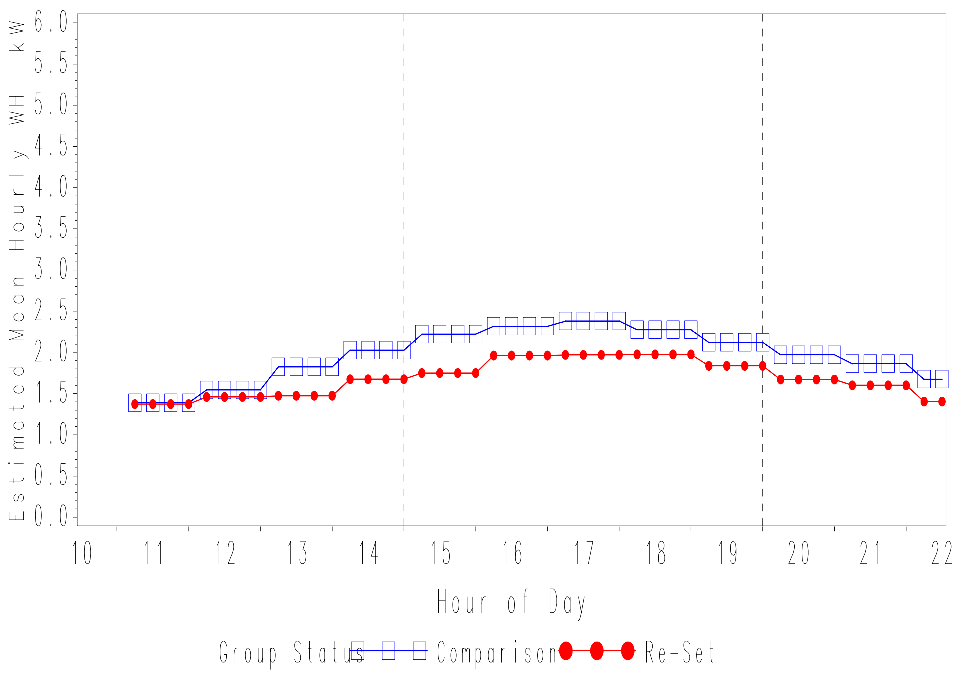

Observed Load by Sample Group, 07OCT05
Observed Mean Hourly WH kW
6.0
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Group Status
Comparison
Re-Set


Re-set Group, Observed v. Estimated, 07OCT05
Mean Hourly WH kW
6.0
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load

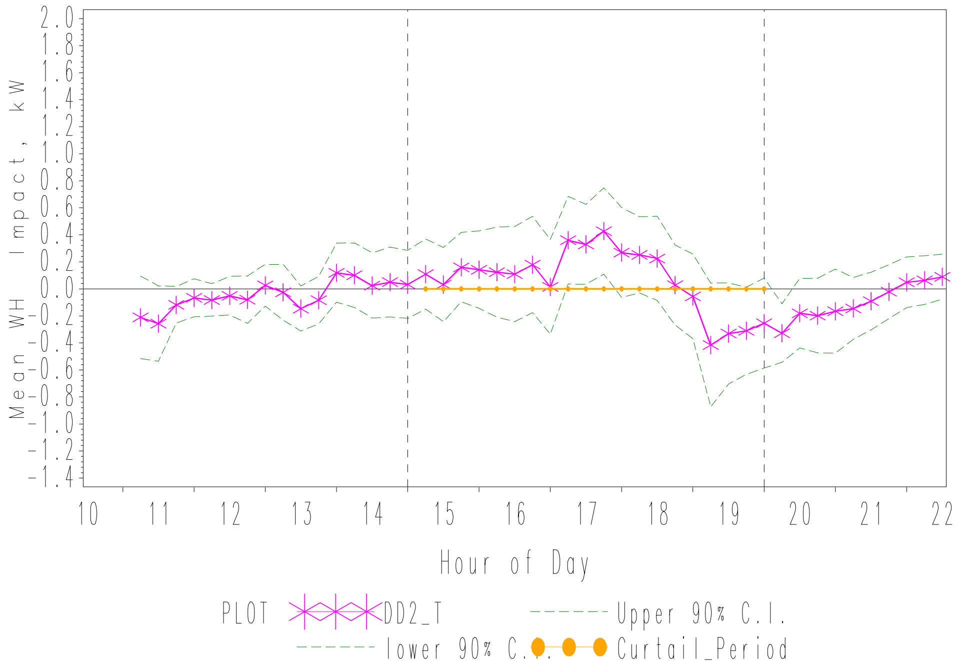
Comparison Group, Actuals v. Estimated, 07OCT05



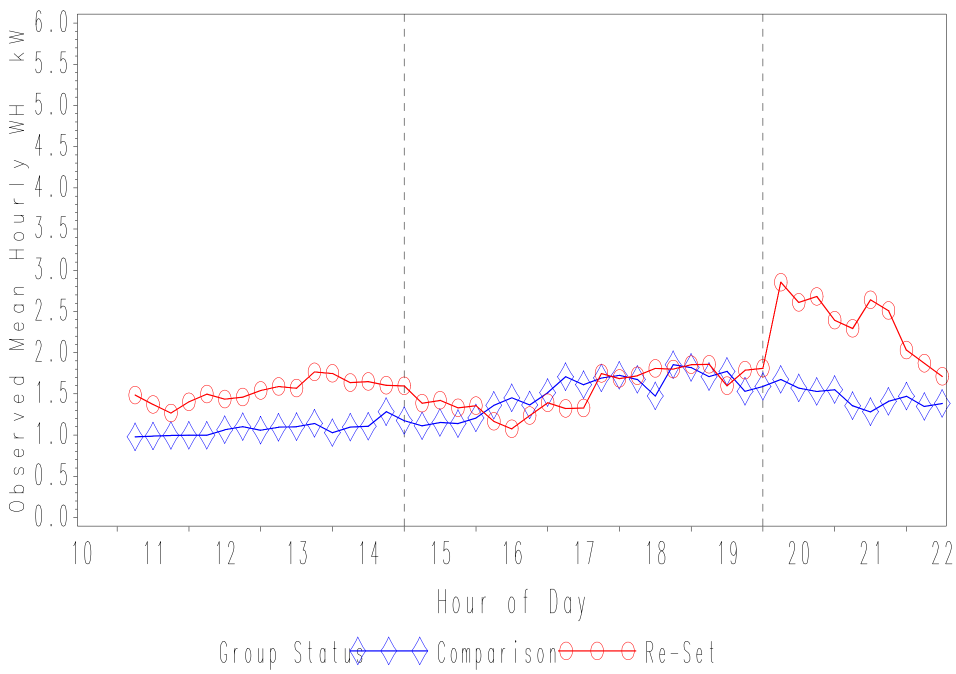
Estimated Load by Sample Group, 07OCT05

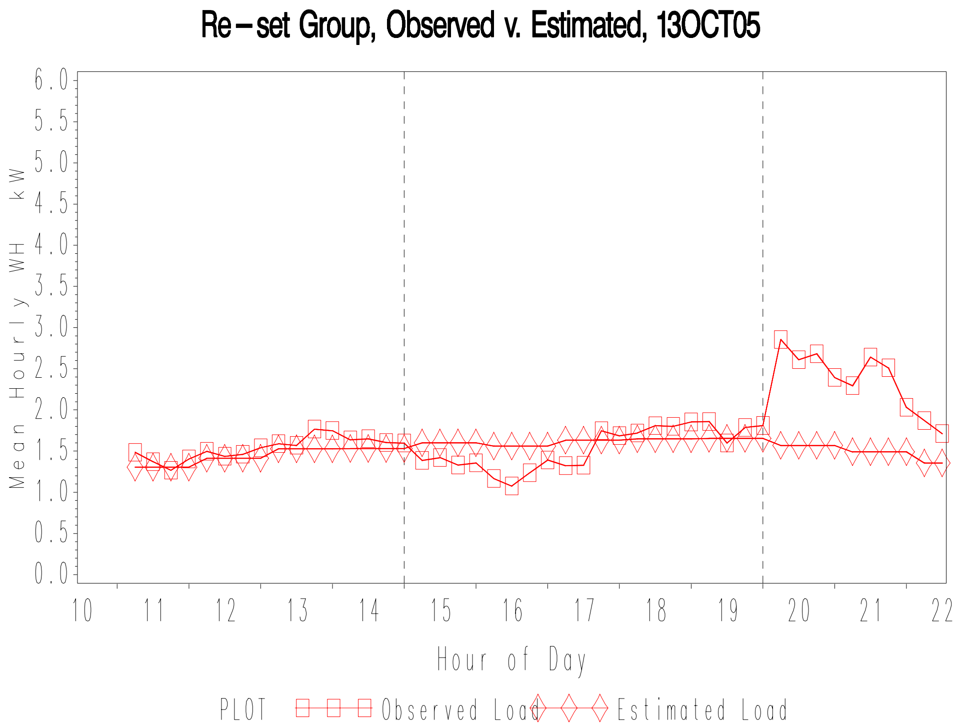


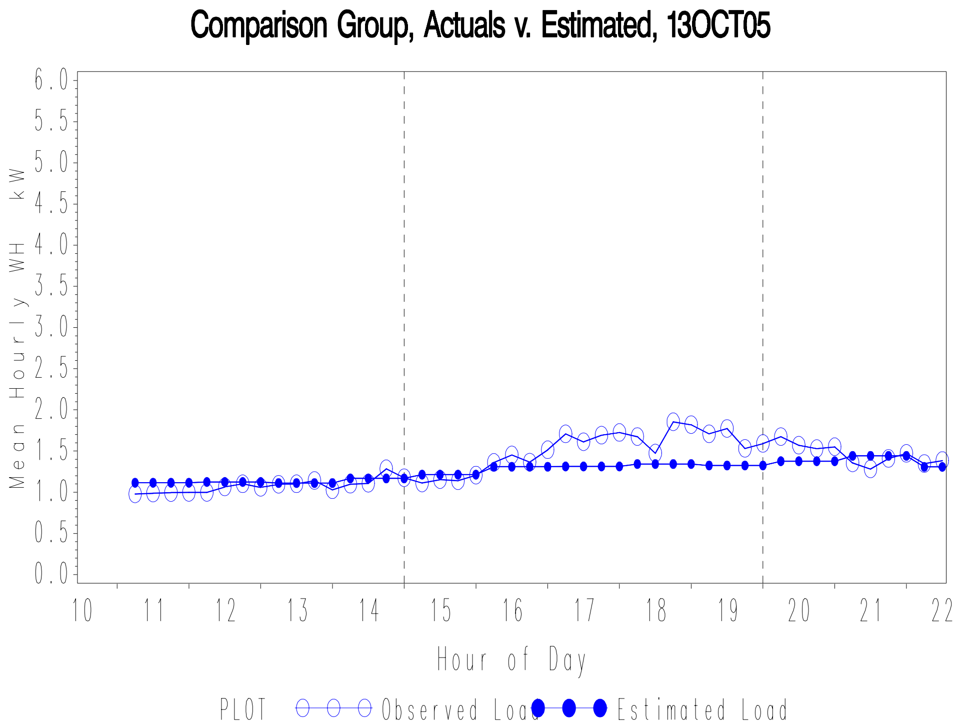
Impact Estimate for 07OCT05

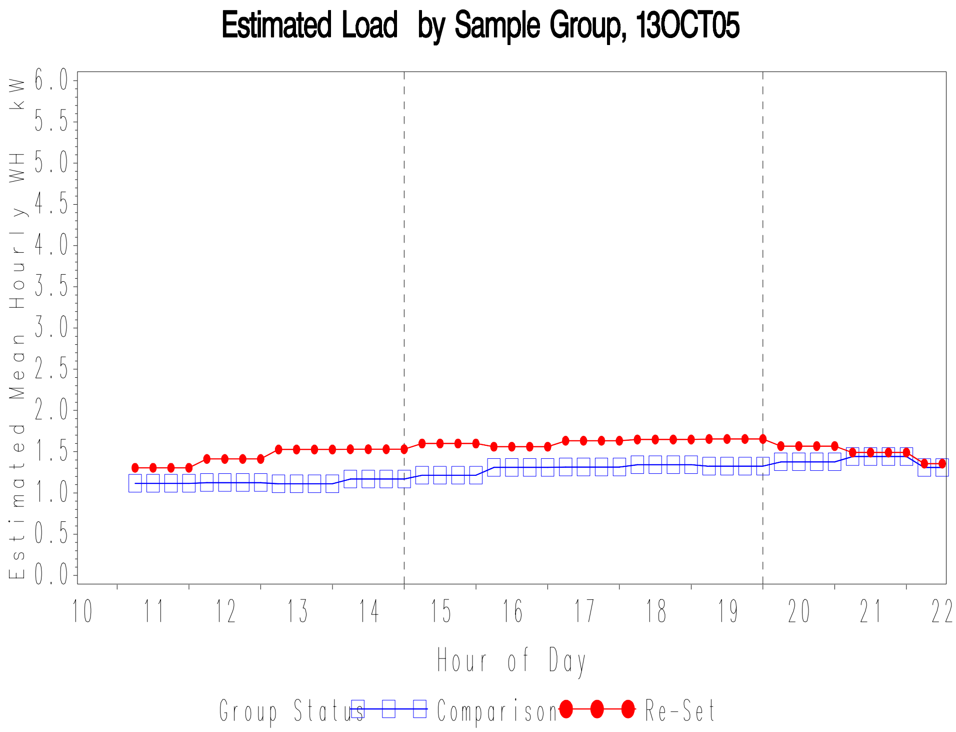


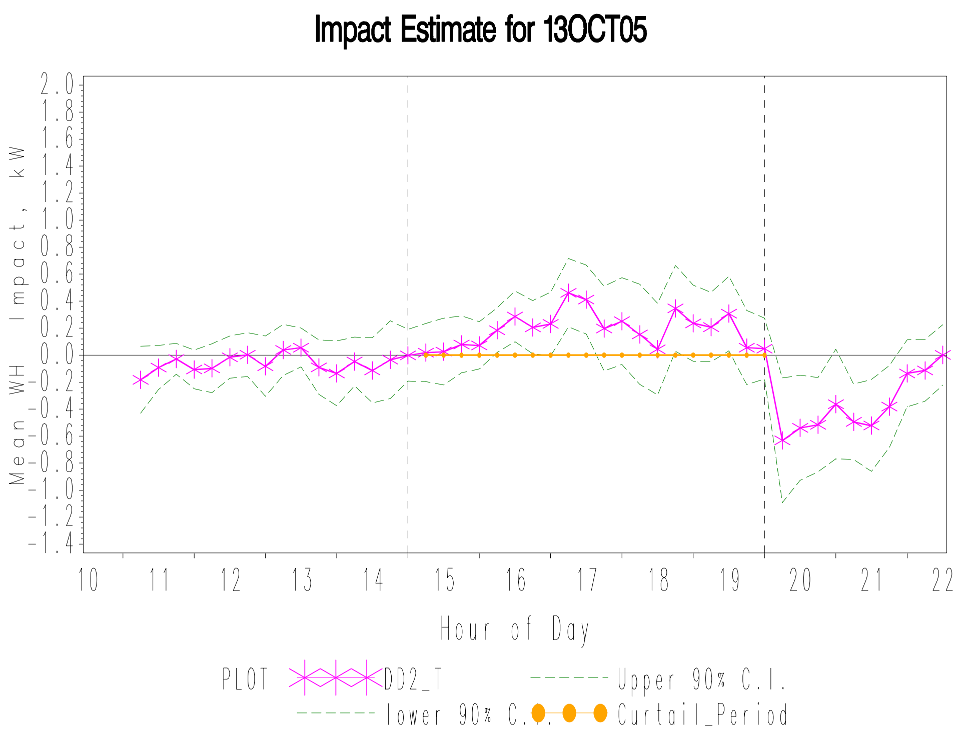
Observed Load by Sample Group, 13OCT05

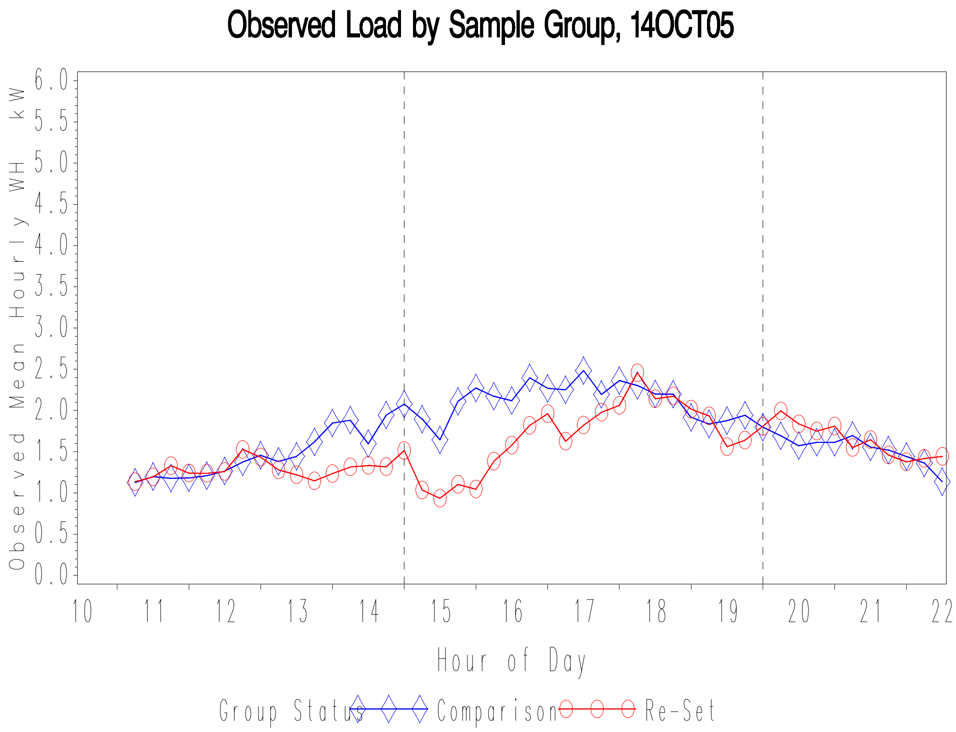



Re−set Group, Observed v. Estimated, 13OCT05
Mean Hourly WH kW
6.0
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT Observed Load Estimated Load

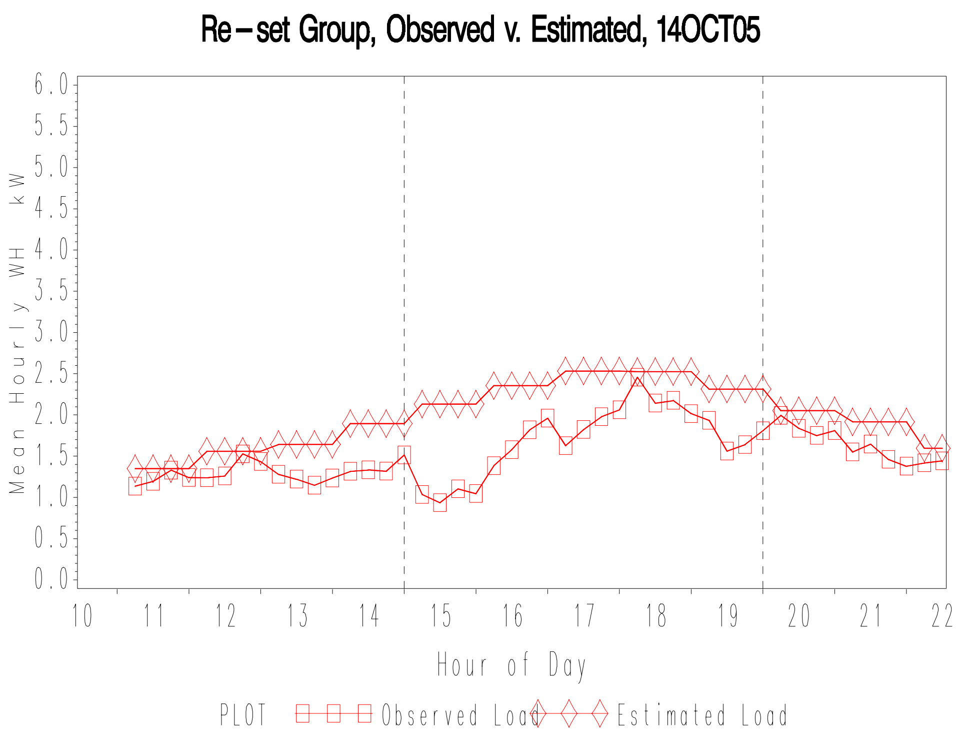

Comparison Group, Actuals v. Estimated, 13OCT05
Mean Hourly WH kW
6.0
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT Observed Load Estimated Load


Estimated Load by Sample Group, 13OCT05
Estimated Mean Hourly WH kW
6.0
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Group Status
Comparison
Re-Set


Impact Estimate for 13OCT05
Mean WH Impact, kW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
-0.6
-0.8
-1.0
-1.2
-1.4
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
DD2_T
Upper 90% C.I.
lower 90% C.I.
Curtail_Period

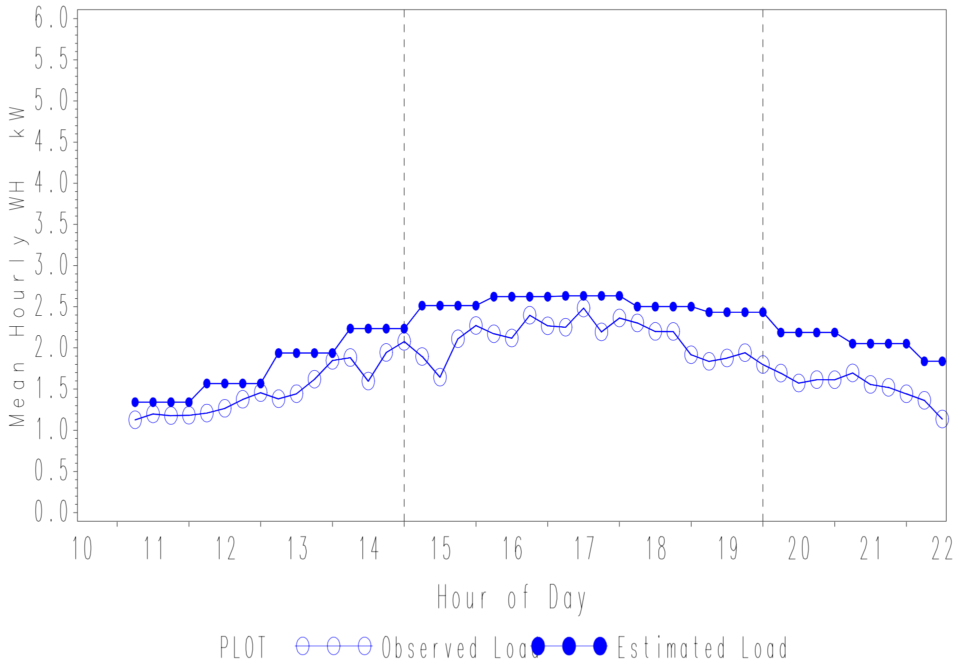


Observed Load by Sample Group, 14OCT05
Observed Hourly WH kW
6.0
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
Group Status
Comparison
Re-Set

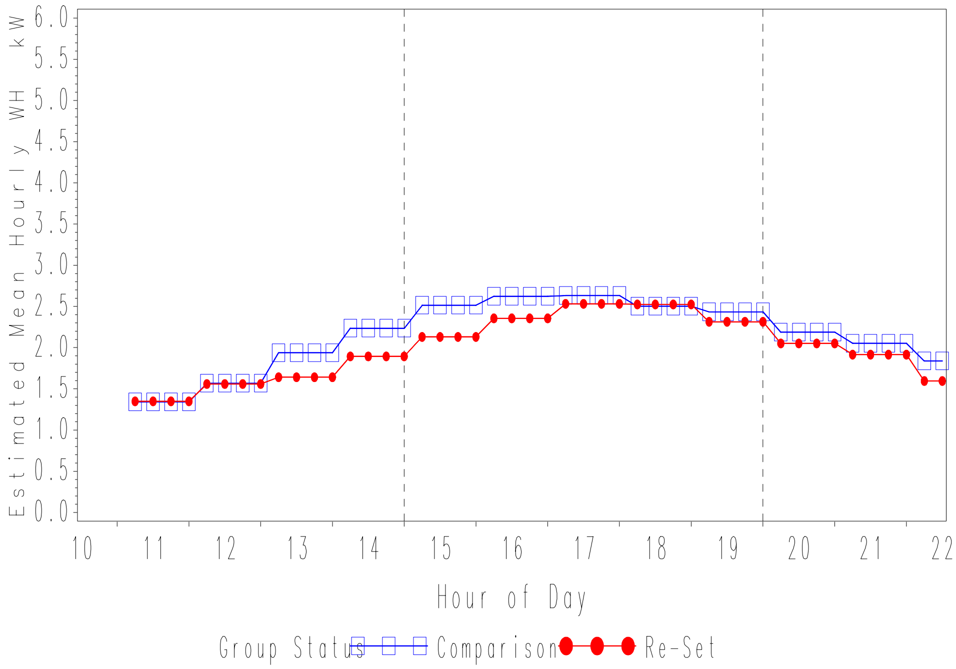


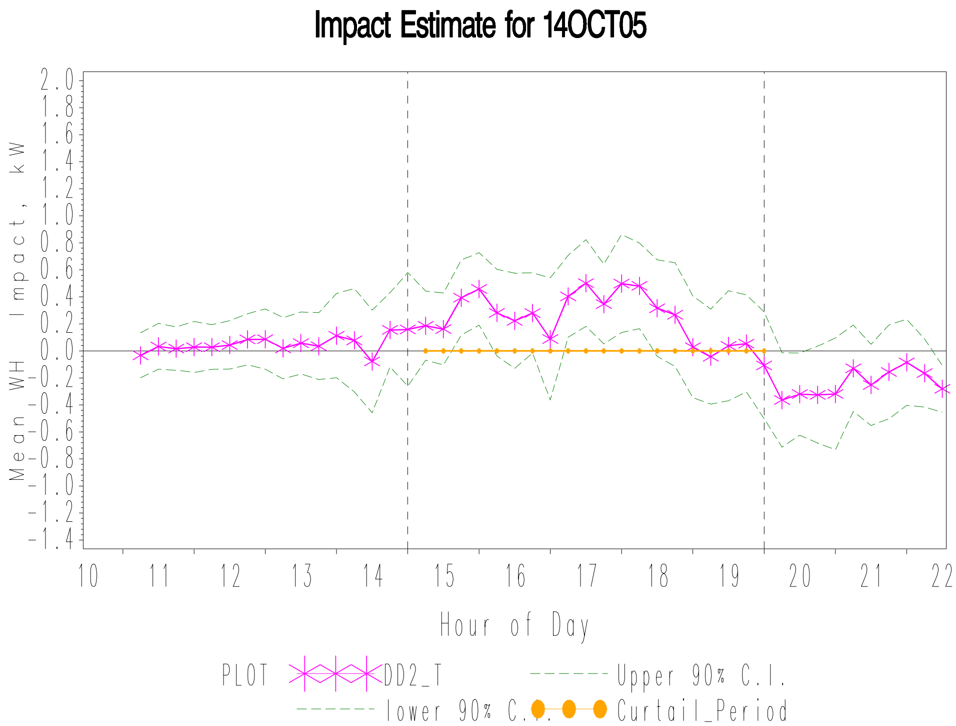
Re-set Group, Observed v. Estimated, 14OCT05
Mean Hourly WH kW
6.0
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT
Observed Load
Estimated Load

Comparison Group, Actuals v. Estimated, 14OCT05



Estimated Load by Sample Group, 14OCT05




Impact Estimate for 14OCT05
Mean_WH Impact, kW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
-0.6
-0.8
-1.0
-1.2
-1.4
10 11 12 13 14 15 16 17 18 19 20 21 22
Hour of Day
PLOT DD2_T
Upper 90% C.I.
lower 90% C.I.
Curtail_Period

C UNADJUSTED PROJECTED SAVINGS PER UNIT

These tables show results for potential contributors only. These are units that respond to the re-set, do not override, and have non-zero AC use over the course of the summer. After a re-set event has occurred, these unadjusted results can be adjusted based on actual re-set day response and override rates and an assumed zero AC use percent.

Table C-1
Unadjusted Projected Savings per AC Unit (kW)
Re-set = 1°F

Daily Average	Hour Ending						Hour Ending 18 Range	
Temperature (°F)	14	15	16	17	18	19	Low	High
65	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.03
66	0.02	0.03	0.03	0.04	0.03	0.03	0.03	0.04
67	0.03	0.04	0.05	0.05	0.05	0.04	0.04	0.05
68	0.04	0.06	0.06	0.06	0.05	0.05	0.05	0.06
69	0.05	0.07	0.08	0.08	0.07	0.06	0.07	0.08
70	0.06	0.08	0.09	0.09	0.09	0.07	0.07	0.09
71	0.08	0.10	0.11	0.11	0.10	0.08	0.09	0.11
72	0.09	0.11	0.13	0.13	0.11	0.09	0.10	0.12
73	0.10	0.12	0.14	0.14	0.12	0.10	0.11	0.15
74	0.12	0.15	0.17	0.18	0.15	0.13	0.14	0.17
75	0.13	0.16	0.19	0.20	0.18	0.15	0.15	0.18
76	0.14	0.17	0.20	0.22	0.20	0.16	0.18	0.22
77	0.14	0.18	0.21	0.23	0.20	0.17	0.19	0.23
78	0.16	0.19	0.23	0.26	0.22	0.18	0.20	0.24
79	0.17	0.22	0.26	0.29	0.25	0.20	0.23	0.26
80	0.18	0.23	0.27	0.29	0.26	0.21	0.25	0.26
81	0.19	0.24	0.28	0.30	0.27	0.22	0.26	0.30
82	0.20	0.25	0.29	0.31	0.28	0.23	0.27	0.31
83	0.22	0.27	0.31	0.34	0.31	0.25	0.27	0.31
84	0.22	0.27	0.31	0.34	0.31	0.25	0.29	0.31
85	0.22	0.27	0.31	0.34	0.31	0.25	0.31	0.31
86	0.22	0.27	0.31	0.34	0.31	0.25	0.31	0.31
87	0.22	0.27	0.31	0.34	0.31	0.25	0.31	0.31
88	0.22	0.27	0.31	0.34	0.31	0.25	0.31	0.31
89	0.22	0.27	0.31	0.34	0.31	0.25	0.31	0.31
90	0.22	0.27	0.31	0.34	0.31	0.25	0.31	0.31
91	0.22	0.27	0.31	0.34	0.31	0.25	0.31	0.31
92	0.22	0.27	0.31	0.34	0.31	0.25	0.31	0.31
93	0.22	0.27	0.31	0.34	0.31	0.25	0.31	0.31
94	0.22	0.27	0.31	0.34	0.31	0.25	0.31	0.31
95	0.22	0.27	0.31	0.34	0.31	0.25	0.31	0.31

Table C-2
Unadjusted Projected Savings per AC Unit (kW)
Re-set = 2°F

Daily Average	Hour Ending						Hour Ending 18 Range	
Temperature (°F)	14	15	16	17	18	19	Low	High
65	0.02	0.03	0.04	0.04	0.04	0.03	0.03	0.04
66	0.04	0.04	0.05	0.06	0.06	0.05	0.05	0.06
67	0.05	0.07	0.08	0.09	0.08	0.07	0.07	0.09
68	0.07	0.10	0.11	0.12	0.10	0.09	0.09	0.11
69	0.09	0.13	0.14	0.14	0.12	0.11	0.11	0.15
70	0.11	0.15	0.17	0.17	0.16	0.14	0.14	0.18
71	0.14	0.18	0.20	0.20	0.19	0.16	0.16	0.20
72	0.16	0.21	0.24	0.24	0.21	0.18	0.19	0.23
73	0.18	0.23	0.27	0.27	0.24	0.20	0.22	0.27
74	0.22	0.27	0.31	0.32	0.28	0.23	0.25	0.32
75	0.25	0.31	0.36	0.38	0.33	0.28	0.29	0.36
76	0.27	0.34	0.39	0.42	0.37	0.31	0.33	0.40
77	0.28	0.35	0.41	0.45	0.40	0.33	0.37	0.45
78	0.30	0.37	0.43	0.49	0.43	0.34	0.39	0.47
79	0.32	0.41	0.49	0.54	0.47	0.38	0.43	0.50
80	0.35	0.45	0.53	0.58	0.51	0.41	0.47	0.53
81	0.38	0.47	0.55	0.60	0.53	0.43	0.51	0.57
82	0.39	0.49	0.57	0.62	0.55	0.44	0.53	0.61
83	0.41	0.51	0.60	0.65	0.59	0.47	0.54	0.61
84	0.43	0.53	0.62	0.67	0.61	0.49	0.56	0.61
85	0.43	0.54	0.63	0.67	0.61	0.49	0.59	0.61
86	0.43	0.54	0.63	0.67	0.61	0.49	0.61	0.61
87	0.43	0.54	0.63	0.67	0.61	0.49	0.61	0.61
88	0.43	0.54	0.63	0.67	0.61	0.49	0.61	0.61
89	0.43	0.54	0.63	0.67	0.61	0.49	0.61	0.61
90	0.43	0.54	0.63	0.67	0.61	0.49	0.61	0.61
91	0.43	0.54	0.63	0.67	0.61	0.49	0.61	0.61
92	0.43	0.54	0.63	0.67	0.61	0.49	0.61	0.61
93	0.43	0.54	0.63	0.67	0.61	0.49	0.61	0.61
94	0.43	0.54	0.63	0.67	0.61	0.49	0.61	0.61
95	0.43	0.54	0.63	0.67	0.61	0.49	0.61	0.61

Table C-3
Unadjusted Projected Savings per AC Unit (kW)
Re-set = 3°F

Daily Average Temperature (°F)	Hour Ending						Hour Ending 18 Range	
	14	15	16	17	18	19	Low	High
65	0.03	0.04	0.05	0.05	0.05	0.04	0.05	0.05
66	0.04	0.06	0.07	0.08	0.07	0.06	0.07	0.08
67	0.06	0.09	0.11	0.11	0.10	0.09	0.09	0.11
68	0.09	0.13	0.15	0.15	0.13	0.12	0.12	0.15
69	0.12	0.17	0.19	0.20	0.17	0.15	0.15	0.20
70	0.16	0.21	0.23	0.23	0.21	0.18	0.19	0.24
71	0.19	0.25	0.28	0.28	0.26	0.22	0.23	0.29
72	0.22	0.29	0.33	0.33	0.30	0.25	0.27	0.33
73	0.26	0.33	0.38	0.38	0.34	0.28	0.31	0.38
74	0.30	0.38	0.44	0.45	0.39	0.32	0.36	0.44
75	0.35	0.44	0.50	0.52	0.45	0.38	0.41	0.50
76	0.39	0.49	0.56	0.60	0.53	0.44	0.47	0.58
77	0.41	0.51	0.59	0.66	0.58	0.48	0.52	0.63
78	0.44	0.55	0.63	0.71	0.62	0.50	0.57	0.69
79	0.47	0.59	0.69	0.77	0.68	0.55	0.62	0.73
80	0.51	0.64	0.76	0.84	0.74	0.59	0.67	0.77
81	0.54	0.69	0.81	0.88	0.79	0.63	0.74	0.83
82	0.57	0.72	0.84	0.91	0.81	0.65	0.78	0.87
83	0.61	0.75	0.88	0.95	0.86	0.69	0.81	0.92
84	0.63	0.78	0.91	0.98	0.89	0.72	0.83	0.92
85	0.65	0.80	0.94	1.01	0.92	0.74	0.86	0.92
86	0.65	0.80	0.94	1.01	0.92	0.74	0.90	0.92
87	0.65	0.80	0.94	1.01	0.92	0.74	0.92	0.92
88	0.65	0.80	0.94	1.01	0.92	0.74	0.92	0.92
89	0.65	0.80	0.94	1.01	0.92	0.74	0.92	0.92
90	0.65	0.80	0.94	1.01	0.92	0.74	0.92	0.92
91	0.65	0.80	0.94	1.01	0.92	0.74	0.92	0.92
92	0.65	0.80	0.94	1.01	0.92	0.74	0.92	0.92
93	0.65	0.80	0.94	1.01	0.92	0.74	0.92	0.92
94	0.65	0.80	0.94	1.01	0.92	0.74	0.92	0.92
95	0.65	0.80	0.94	1.01	0.92	0.74	0.92	0.92

Table C-4
Unadjusted Projected Savings per AC Unit (kW)
Re-set = 4°F

Daily Average	Hour Ending						Hour Ending 18 Range	
Temperature (°F)	14	15	16	17	18	19	Low	High
65	0.03	0.04	0.05	0.06	0.05	0.04	0.05	0.06
66	0.05	0.07	0.08	0.09	0.08	0.07	0.08	0.09
67	0.07	0.10	0.12	0.13	0.12	0.10	0.11	0.13
68	0.11	0.14	0.17	0.18	0.15	0.13	0.14	0.18
69	0.15	0.20	0.23	0.23	0.20	0.18	0.19	0.24
70	0.19	0.25	0.28	0.29	0.26	0.22	0.23	0.29
71	0.23	0.31	0.34	0.35	0.31	0.27	0.28	0.35
72	0.28	0.36	0.41	0.41	0.37	0.31	0.33	0.41
73	0.32	0.41	0.47	0.47	0.42	0.35	0.38	0.47
74	0.38	0.48	0.55	0.56	0.49	0.41	0.45	0.55
75	0.43	0.55	0.63	0.65	0.57	0.47	0.51	0.62
76	0.48	0.61	0.70	0.74	0.65	0.54	0.58	0.72
77	0.53	0.66	0.76	0.83	0.73	0.60	0.67	0.80
78	0.57	0.71	0.82	0.91	0.80	0.65	0.72	0.87
79	0.61	0.76	0.89	0.99	0.87	0.71	0.80	0.95
80	0.65	0.82	0.96	1.07	0.94	0.76	0.86	0.99
81	0.70	0.88	1.04	1.14	1.01	0.81	0.93	1.07
82	0.74	0.93	1.10	1.20	1.07	0.86	1.01	1.14
83	0.79	0.98	1.15	1.25	1.12	0.90	1.05	1.18
84	0.82	1.02	1.20	1.29	1.16	0.94	1.09	1.22
85	0.85	1.05	1.23	1.32	1.20	0.96	1.14	1.23
86	0.86	1.07	1.25	1.34	1.23	0.98	1.17	1.23
87	0.86	1.07	1.25	1.34	1.23	0.98	1.21	1.23
88	0.86	1.07	1.25	1.34	1.23	0.98	1.23	1.23
89	0.86	1.07	1.25	1.34	1.23	0.98	1.23	1.23
90	0.86	1.07	1.25	1.34	1.23	0.98	1.23	1.23
91	0.86	1.07	1.25	1.34	1.23	0.98	1.23	1.23
92	0.86	1.07	1.25	1.34	1.23	0.98	1.23	1.23
93	0.86	1.07	1.25	1.34	1.23	0.98	1.23	1.23
94	0.86	1.07	1.25	1.34	1.23	0.98	1.23	1.23
95	0.86	1.07	1.25	1.34	1.23	0.98	1.23	1.23

Table C-5
Unadjusted Projected Savings per AC Unit (kW)
Re-set = 5°F

Daily Average Temperature (°F)	Hour Ending						Hour Ending 18 Range	
	14	15	16	17	18	19	Low	High
65	0.03	0.05	0.05	0.06	0.06	0.04	0.05	0.06
66	0.05	0.07	0.08	0.09	0.09	0.07	0.08	0.10
67	0.08	0.11	0.13	0.14	0.13	0.11	0.12	0.14
68	0.11	0.16	0.18	0.19	0.17	0.14	0.15	0.19
69	0.16	0.21	0.25	0.26	0.23	0.20	0.21	0.26
70	0.21	0.28	0.32	0.33	0.29	0.25	0.26	0.33
71	0.26	0.35	0.39	0.40	0.36	0.30	0.32	0.40
72	0.32	0.42	0.47	0.47	0.42	0.36	0.38	0.47
73	0.37	0.48	0.55	0.55	0.49	0.41	0.45	0.56
74	0.44	0.56	0.64	0.65	0.58	0.48	0.52	0.65
75	0.51	0.64	0.74	0.76	0.67	0.55	0.60	0.74
76	0.57	0.72	0.82	0.87	0.76	0.63	0.69	0.84
77	0.63	0.79	0.91	0.98	0.85	0.70	0.78	0.95
78	0.68	0.86	0.99	1.09	0.95	0.78	0.86	1.04
79	0.73	0.93	1.08	1.20	1.05	0.86	0.95	1.13
80	0.79	0.99	1.16	1.29	1.13	0.92	1.04	1.21
81	0.84	1.06	1.25	1.37	1.21	0.98	1.13	1.30
82	0.90	1.13	1.33	1.45	1.29	1.04	1.20	1.38
83	0.96	1.20	1.41	1.53	1.37	1.10	1.28	1.44
84	1.01	1.25	1.47	1.58	1.43	1.14	1.34	1.49
85	1.04	1.29	1.51	1.62	1.47	1.18	1.40	1.53
86	1.06	1.32	1.54	1.65	1.51	1.21	1.44	1.53
87	1.08	1.34	1.56	1.68	1.53	1.23	1.48	1.53
88	1.08	1.34	1.56	1.68	1.53	1.23	1.51	1.53
89	1.08	1.34	1.57	1.68	1.53	1.23	1.53	1.53
90	1.08	1.34	1.57	1.68	1.53	1.23	1.53	1.53
91	1.08	1.34	1.57	1.68	1.53	1.23	1.53	1.53
92	1.08	1.34	1.57	1.68	1.53	1.23	1.53	1.53
93	1.08	1.34	1.57	1.68	1.53	1.23	1.53	1.53
94	1.08	1.34	1.57	1.68	1.53	1.23	1.53	1.53
95	1.08	1.34	1.57	1.68	1.53	1.23	1.53	1.53

D

ADJUSTED PROJECTED SAVINGS PER UNIT

These tables show the average per unit savings across all program units. Savings have been adjusted to reflect 2004 average rates of non-response and zero AC use as well as the estimate of override percent. The estimate of override percent is a function of both the duration of the event and the amount re-set are needed. Choose the correct table based on these two variables. These results provide the best means of projecting per unit savings prior to a re-set event.

Table D-1
Adjusted Projected Savings per AC Unit (kW)
Duration = 2 hours, Re-set = 1°F

Daily Average Temperature (°F)	Hour Ending						Hour Ending 18 Range	
	14	15	16	17	18	19	Low	High
65	0.01	0.01	0.02	0.02	0.02	0.01	0.02	0.02
66	0.02	0.02	0.02	0.03	0.02	0.02	0.02	0.03
67	0.02	0.03	0.04	0.04	0.03	0.03	0.03	0.04
68	0.03	0.04	0.05	0.04	0.04	0.03	0.03	0.05
69	0.04	0.05	0.06	0.06	0.05	0.04	0.05	0.06
70	0.04	0.06	0.06	0.06	0.06	0.05	0.05	0.06
71	0.05	0.07	0.08	0.08	0.07	0.06	0.06	0.08
72	0.06	0.08	0.09	0.09	0.08	0.06	0.07	0.08
73	0.07	0.08	0.10	0.09	0.08	0.07	0.08	0.10
74	0.08	0.10	0.11	0.12	0.10	0.08	0.09	0.11
75	0.08	0.11	0.12	0.13	0.12	0.10	0.10	0.12
76	0.09	0.11	0.13	0.14	0.13	0.10	0.11	0.14
77	0.09	0.11	0.13	0.15	0.13	0.10	0.12	0.14
78	0.10	0.12	0.14	0.16	0.14	0.11	0.12	0.15
79	0.10	0.13	0.15	0.17	0.15	0.12	0.14	0.16
80	0.11	0.13	0.16	0.17	0.15	0.12	0.14	0.15
81	0.11	0.14	0.16	0.17	0.15	0.12	0.15	0.17
82	0.11	0.13	0.16	0.17	0.15	0.12	0.15	0.17
83	0.11	0.14	0.16	0.17	0.16	0.13	0.14	0.16
84	0.11	0.13	0.15	0.17	0.15	0.12	0.14	0.15
85	0.10	0.13	0.15	0.16	0.14	0.12	0.14	0.14
86	0.10	0.12	0.14	0.15	0.14	0.11	0.14	0.14
87	0.09	0.11	0.13	0.14	0.13	0.10	0.13	0.13
88	0.08	0.10	0.12	0.13	0.12	0.09	0.12	0.12
89	0.08	0.09	0.11	0.12	0.11	0.09	0.11	0.11
90	0.07	0.08	0.10	0.11	0.10	0.08	0.10	0.10
91	0.06	0.07	0.09	0.09	0.09	0.07	0.09	0.09
92	0.05	0.07	0.08	0.08	0.07	0.06	0.07	0.07
93	0.04	0.06	0.06	0.07	0.06	0.05	0.06	0.06
94	0.04	0.05	0.05	0.06	0.05	0.04	0.05	0.05
95	0.03	0.04	0.04	0.04	0.04	0.03	0.04	0.04

Table D-2
Adjusted Projected Savings per AC Unit (kW)
Duration = 2 hours, Re-set = 2°F

Daily Average Temperature (°F)	Hour Ending						Hour Ending 18 Range	
	14	15	16	17	18	19	Low	High
65	0.02	0.02	0.03	0.03	0.03	0.02	0.03	0.03
66	0.03	0.03	0.04	0.04	0.04	0.03	0.04	0.05
67	0.04	0.05	0.06	0.07	0.06	0.05	0.05	0.06
68	0.05	0.07	0.08	0.08	0.07	0.06	0.06	0.08
69	0.07	0.09	0.10	0.10	0.09	0.08	0.08	0.10
70	0.08	0.11	0.12	0.12	0.11	0.09	0.10	0.12
71	0.10	0.12	0.14	0.14	0.13	0.11	0.11	0.14
72	0.11	0.14	0.16	0.16	0.15	0.12	0.13	0.16
73	0.12	0.16	0.18	0.18	0.16	0.13	0.15	0.18
74	0.14	0.18	0.21	0.21	0.18	0.15	0.17	0.21
75	0.16	0.20	0.23	0.25	0.22	0.18	0.19	0.23
76	0.17	0.21	0.25	0.27	0.24	0.20	0.21	0.26
77	0.18	0.22	0.25	0.28	0.25	0.21	0.23	0.28
78	0.18	0.23	0.27	0.30	0.26	0.21	0.24	0.29
79	0.19	0.25	0.29	0.32	0.28	0.23	0.25	0.30
80	0.20	0.26	0.31	0.34	0.30	0.24	0.27	0.31
81	0.21	0.26	0.31	0.34	0.30	0.24	0.28	0.32
82	0.21	0.26	0.31	0.33	0.30	0.24	0.29	0.33
83	0.21	0.27	0.31	0.34	0.30	0.24	0.28	0.32
84	0.21	0.26	0.31	0.33	0.30	0.24	0.28	0.30
85	0.20	0.25	0.29	0.31	0.29	0.23	0.28	0.29
86	0.19	0.24	0.28	0.30	0.27	0.22	0.27	0.27
87	0.18	0.22	0.26	0.28	0.25	0.20	0.25	0.25
88	0.16	0.20	0.24	0.26	0.23	0.19	0.23	0.23
89	0.15	0.19	0.22	0.23	0.21	0.17	0.21	0.21
90	0.14	0.17	0.20	0.21	0.19	0.15	0.19	0.19
91	0.12	0.15	0.17	0.19	0.17	0.14	0.17	0.17
92	0.10	0.13	0.15	0.16	0.15	0.12	0.15	0.15
93	0.09	0.11	0.13	0.14	0.13	0.10	0.13	0.13
94	0.07	0.09	0.11	0.11	0.10	0.08	0.10	0.10
95	0.06	0.07	0.08	0.09	0.08	0.06	0.08	0.08

Table D-3
Adjusted Projected Savings per AC Unit (kW)
Duration = 2 hours, Re-set = 3°F

Daily Average Temperature (°F)	Hour Ending						Hour Ending 18 Range	
	14	15	16	17	18	19	Low	High
65	0.02	0.03	0.03	0.04	0.03	0.03	0.03	0.04
66	0.03	0.04	0.05	0.06	0.05	0.04	0.05	0.06
67	0.05	0.06	0.08	0.08	0.07	0.06	0.07	0.08
68	0.07	0.09	0.10	0.11	0.09	0.08	0.09	0.11
69	0.09	0.12	0.14	0.14	0.12	0.10	0.11	0.14
70	0.11	0.15	0.16	0.16	0.15	0.13	0.13	0.17
71	0.13	0.17	0.19	0.20	0.18	0.15	0.16	0.20
72	0.15	0.20	0.22	0.22	0.20	0.17	0.18	0.22
73	0.17	0.22	0.26	0.25	0.23	0.19	0.21	0.26
74	0.20	0.25	0.29	0.30	0.26	0.21	0.24	0.29
75	0.23	0.29	0.33	0.34	0.30	0.25	0.26	0.33
76	0.25	0.31	0.36	0.39	0.34	0.28	0.30	0.37
77	0.26	0.32	0.37	0.41	0.36	0.30	0.33	0.39
78	0.27	0.33	0.39	0.43	0.38	0.31	0.35	0.42
79	0.28	0.35	0.41	0.46	0.40	0.33	0.37	0.44
80	0.29	0.37	0.44	0.48	0.43	0.34	0.39	0.44
81	0.31	0.39	0.46	0.50	0.44	0.35	0.41	0.47
82	0.31	0.39	0.46	0.49	0.44	0.35	0.42	0.47
83	0.31	0.39	0.46	0.49	0.45	0.36	0.42	0.48
84	0.31	0.39	0.45	0.49	0.44	0.35	0.41	0.46
85	0.30	0.38	0.44	0.47	0.43	0.35	0.41	0.43
86	0.29	0.35	0.41	0.44	0.41	0.33	0.40	0.41
87	0.27	0.33	0.39	0.42	0.38	0.30	0.38	0.38
88	0.25	0.31	0.36	0.38	0.35	0.28	0.35	0.35
89	0.23	0.28	0.33	0.35	0.32	0.26	0.32	0.32
90	0.20	0.25	0.30	0.32	0.29	0.23	0.29	0.29
91	0.18	0.22	0.26	0.28	0.26	0.21	0.26	0.26
92	0.16	0.20	0.23	0.24	0.22	0.18	0.22	0.22
93	0.13	0.17	0.19	0.21	0.19	0.15	0.19	0.19
94	0.11	0.14	0.16	0.17	0.15	0.12	0.15	0.15
95	0.08	0.11	0.12	0.13	0.12	0.10	0.12	0.12

Table D-4
Adjusted Projected Savings per AC Unit (kW)
Duration = 2 hours, Re-set = 4°F

Daily Average Temperature (°F)	Hour Ending						Hour Ending 18 Range	
	14	15	16	17	18	19	Low	High
65	0.02	0.03	0.04	0.04	0.04	0.03	0.04	0.04
66	0.04	0.05	0.06	0.06	0.06	0.05	0.06	0.07
67	0.05	0.07	0.09	0.09	0.08	0.07	0.08	0.09
68	0.08	0.10	0.12	0.13	0.11	0.09	0.10	0.13
69	0.10	0.14	0.16	0.17	0.14	0.13	0.13	0.17
70	0.13	0.17	0.20	0.20	0.18	0.15	0.16	0.20
71	0.16	0.21	0.24	0.24	0.21	0.18	0.19	0.24
72	0.19	0.24	0.28	0.28	0.25	0.21	0.23	0.28
73	0.22	0.28	0.32	0.32	0.28	0.24	0.26	0.32
74	0.25	0.32	0.36	0.37	0.32	0.27	0.30	0.37
75	0.28	0.36	0.41	0.42	0.37	0.31	0.33	0.41
76	0.31	0.39	0.45	0.48	0.42	0.35	0.37	0.46
77	0.33	0.42	0.48	0.52	0.46	0.38	0.42	0.50
78	0.35	0.43	0.50	0.56	0.49	0.40	0.44	0.53
79	0.36	0.45	0.53	0.59	0.52	0.42	0.48	0.57
80	0.38	0.48	0.56	0.62	0.54	0.44	0.50	0.58
81	0.39	0.49	0.58	0.64	0.57	0.45	0.52	0.60
82	0.40	0.50	0.60	0.65	0.58	0.46	0.55	0.61
83	0.41	0.51	0.60	0.65	0.58	0.47	0.55	0.61
84	0.41	0.51	0.59	0.64	0.58	0.46	0.54	0.61
85	0.40	0.49	0.58	0.62	0.56	0.45	0.53	0.58
86	0.38	0.47	0.55	0.59	0.54	0.43	0.52	0.54
87	0.36	0.44	0.52	0.55	0.51	0.41	0.50	0.51
88	0.33	0.41	0.48	0.51	0.47	0.37	0.47	0.47
89	0.30	0.37	0.44	0.47	0.43	0.34	0.43	0.43
90	0.27	0.34	0.39	0.42	0.39	0.31	0.39	0.39
91	0.24	0.30	0.35	0.38	0.34	0.27	0.34	0.34
92	0.21	0.26	0.30	0.33	0.30	0.24	0.30	0.30
93	0.18	0.22	0.26	0.28	0.25	0.20	0.25	0.25
94	0.15	0.18	0.21	0.23	0.21	0.17	0.21	0.21
95	0.11	0.14	0.16	0.18	0.16	0.13	0.16	0.16

Table D-5
Adjusted Projected Savings per AC Unit (kW)
Duration = 2 hours, Re-set = 5°F

Daily Average	Hour Ending						Hour Ending 18 Range	
Temperature (°F)	14	15	16	17	18	19	Low	High
65	0.02	0.03	0.04	0.04	0.04	0.03	0.04	0.05
66	0.04	0.05	0.06	0.07	0.06	0.05	0.06	0.07
67	0.06	0.08	0.09	0.10	0.09	0.08	0.08	0.10
68	0.08	0.11	0.13	0.14	0.12	0.10	0.11	0.14
69	0.11	0.15	0.17	0.18	0.16	0.14	0.15	0.18
70	0.14	0.19	0.22	0.23	0.20	0.18	0.18	0.23
71	0.18	0.24	0.27	0.28	0.25	0.21	0.22	0.28
72	0.22	0.28	0.32	0.32	0.29	0.24	0.26	0.32
73	0.25	0.32	0.37	0.37	0.33	0.28	0.30	0.37
74	0.29	0.37	0.42	0.43	0.38	0.32	0.34	0.43
75	0.33	0.42	0.48	0.50	0.44	0.36	0.39	0.48
76	0.36	0.46	0.53	0.56	0.49	0.40	0.44	0.54
77	0.39	0.49	0.57	0.61	0.53	0.44	0.49	0.59
78	0.42	0.53	0.61	0.67	0.58	0.48	0.53	0.64
79	0.44	0.55	0.64	0.71	0.63	0.51	0.57	0.68
80	0.46	0.57	0.67	0.75	0.66	0.53	0.60	0.70
81	0.47	0.60	0.70	0.77	0.68	0.55	0.63	0.73
82	0.49	0.61	0.72	0.78	0.70	0.56	0.65	0.74
83	0.50	0.62	0.73	0.79	0.71	0.57	0.66	0.75
84	0.50	0.62	0.73	0.78	0.71	0.57	0.66	0.74
85	0.49	0.60	0.71	0.76	0.69	0.55	0.66	0.72
86	0.47	0.58	0.68	0.73	0.67	0.53	0.64	0.68
87	0.44	0.55	0.64	0.69	0.63	0.51	0.61	0.63
88	0.41	0.51	0.60	0.64	0.58	0.47	0.58	0.58
89	0.38	0.47	0.55	0.59	0.53	0.43	0.53	0.53
90	0.34	0.42	0.49	0.53	0.48	0.39	0.48	0.48
91	0.30	0.37	0.44	0.47	0.43	0.34	0.43	0.43
92	0.26	0.33	0.38	0.41	0.37	0.30	0.37	0.37
93	0.22	0.28	0.32	0.35	0.32	0.25	0.32	0.32
94	0.18	0.23	0.26	0.28	0.26	0.21	0.26	0.26
95	0.14	0.18	0.20	0.22	0.20	0.16	0.20	0.20

Table D-6
Adjusted Projected Savings per AC Unit (kW)
Duration = 3 hours, Re-set = 1°F

Daily Average Temperature (°F)	Hour Ending						Hour Ending 18 Range	
	14	15	16	17	18	19	Low	High
65	0.01	0.01	0.02	0.02	0.02	0.01	0.02	0.02
66	0.02	0.02	0.02	0.03	0.02	0.02	0.02	0.03
67	0.02	0.03	0.04	0.04	0.03	0.03	0.03	0.03
68	0.03	0.04	0.04	0.04	0.04	0.03	0.03	0.04
69	0.04	0.05	0.05	0.05	0.05	0.04	0.05	0.06
70	0.04	0.05	0.06	0.06	0.06	0.05	0.05	0.06
71	0.05	0.06	0.07	0.07	0.07	0.06	0.06	0.07
72	0.06	0.07	0.08	0.08	0.07	0.06	0.07	0.08
73	0.06	0.08	0.09	0.09	0.08	0.07	0.07	0.09
74	0.07	0.09	0.11	0.11	0.10	0.08	0.09	0.11
75	0.08	0.10	0.11	0.12	0.11	0.09	0.09	0.11
76	0.08	0.10	0.12	0.13	0.12	0.10	0.11	0.13
77	0.08	0.10	0.12	0.13	0.12	0.10	0.11	0.13
78	0.09	0.11	0.13	0.14	0.13	0.10	0.11	0.13
79	0.09	0.12	0.14	0.16	0.14	0.11	0.12	0.14
80	0.09	0.12	0.14	0.15	0.14	0.11	0.13	0.14
81	0.10	0.12	0.14	0.15	0.14	0.11	0.13	0.15
82	0.09	0.12	0.14	0.15	0.13	0.11	0.13	0.14
83	0.10	0.12	0.14	0.15	0.14	0.11	0.12	0.14
84	0.09	0.11	0.13	0.14	0.13	0.10	0.12	0.13
85	0.08	0.10	0.12	0.13	0.12	0.09	0.12	0.12
86	0.08	0.09	0.11	0.12	0.11	0.09	0.11	0.11
87	0.07	0.09	0.10	0.11	0.10	0.08	0.10	0.10
88	0.06	0.08	0.09	0.09	0.09	0.07	0.09	0.09
89	0.05	0.07	0.08	0.08	0.08	0.06	0.08	0.08
90	0.05	0.06	0.07	0.07	0.06	0.05	0.06	0.06
91	0.04	0.05	0.05	0.06	0.05	0.04	0.05	0.05
92	0.03	0.04	0.04	0.05	0.04	0.03	0.04	0.04
93	0.02	0.03	0.03	0.03	0.03	0.02	0.03	0.03
94	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02
95	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01

Table D-7
Adjusted Projected Savings per AC Unit (kW)
Duration = 3 hours, Re-set = 2°F

Daily Average Temperature (°F)	Hour Ending						Hour Ending 18 Range	
	14	15	16	17	18	19	Low	High
65	0.02	0.02	0.03	0.03	0.03	0.02	0.02	0.03
66	0.02	0.03	0.04	0.04	0.04	0.03	0.04	0.05
67	0.04	0.05	0.06	0.06	0.06	0.05	0.05	0.06
68	0.05	0.07	0.08	0.08	0.07	0.06	0.06	0.08
69	0.06	0.09	0.10	0.10	0.08	0.07	0.08	0.10
70	0.08	0.10	0.11	0.12	0.11	0.09	0.09	0.12
71	0.09	0.12	0.13	0.13	0.12	0.10	0.11	0.14
72	0.11	0.14	0.16	0.16	0.14	0.11	0.13	0.15
73	0.12	0.15	0.17	0.17	0.15	0.13	0.14	0.17
74	0.14	0.17	0.20	0.20	0.17	0.14	0.16	0.20
75	0.15	0.19	0.22	0.23	0.20	0.17	0.18	0.22
76	0.16	0.20	0.23	0.25	0.22	0.19	0.20	0.24
77	0.16	0.20	0.24	0.26	0.23	0.19	0.22	0.26
78	0.17	0.21	0.24	0.27	0.24	0.19	0.22	0.26
79	0.18	0.22	0.26	0.29	0.26	0.21	0.23	0.27
80	0.18	0.23	0.28	0.30	0.27	0.22	0.25	0.27
81	0.19	0.23	0.27	0.30	0.27	0.21	0.25	0.28
82	0.18	0.23	0.27	0.29	0.26	0.21	0.25	0.29
83	0.18	0.23	0.27	0.29	0.26	0.21	0.24	0.27
84	0.18	0.22	0.26	0.28	0.25	0.20	0.23	0.25
85	0.17	0.21	0.24	0.26	0.24	0.19	0.23	0.24
86	0.15	0.19	0.22	0.24	0.22	0.17	0.22	0.22
87	0.14	0.17	0.20	0.21	0.19	0.16	0.19	0.19
88	0.12	0.15	0.18	0.19	0.17	0.14	0.17	0.17
89	0.11	0.13	0.15	0.17	0.15	0.12	0.15	0.15
90	0.09	0.11	0.13	0.14	0.13	0.10	0.13	0.13
91	0.07	0.09	0.11	0.12	0.11	0.08	0.11	0.11
92	0.06	0.07	0.08	0.09	0.08	0.07	0.08	0.08
93	0.04	0.05	0.06	0.07	0.06	0.05	0.06	0.06
94	0.03	0.03	0.04	0.04	0.04	0.03	0.04	0.04
95	0.01	0.02	0.02	0.02	0.02	0.01	0.02	0.02

Table D-8
Adjusted Projected Savings per AC Unit (kW)
Duration = 3 hours, Re-set = 3°F

Daily Average	Hour Ending						Hour Ending 18 Range	
Temperature (°F)	14	15	16	17	18	19	Low	High
65	0.02	0.03	0.03	0.04	0.03	0.03	0.03	0.04
66	0.03	0.04	0.05	0.05	0.05	0.04	0.05	0.06
67	0.04	0.06	0.07	0.08	0.07	0.06	0.07	0.08
68	0.06	0.09	0.10	0.11	0.09	0.08	0.08	0.10
69	0.08	0.12	0.13	0.13	0.12	0.10	0.11	0.13
70	0.11	0.14	0.16	0.16	0.14	0.12	0.13	0.16
71	0.13	0.17	0.19	0.19	0.17	0.15	0.15	0.19
72	0.15	0.19	0.21	0.21	0.20	0.16	0.17	0.21
73	0.17	0.21	0.24	0.24	0.22	0.18	0.20	0.24
74	0.19	0.24	0.28	0.28	0.24	0.20	0.22	0.28
75	0.21	0.27	0.31	0.32	0.28	0.23	0.25	0.31
76	0.23	0.29	0.33	0.36	0.31	0.26	0.28	0.34
77	0.24	0.30	0.34	0.38	0.33	0.28	0.31	0.37
78	0.25	0.31	0.36	0.40	0.35	0.28	0.32	0.39
79	0.25	0.32	0.38	0.42	0.37	0.30	0.34	0.40
80	0.26	0.33	0.39	0.43	0.38	0.31	0.35	0.40
81	0.27	0.34	0.40	0.44	0.39	0.31	0.37	0.41
82	0.27	0.34	0.40	0.43	0.38	0.31	0.37	0.41
83	0.27	0.33	0.39	0.42	0.38	0.31	0.36	0.41
84	0.26	0.32	0.38	0.41	0.37	0.30	0.34	0.38
85	0.25	0.31	0.36	0.39	0.35	0.28	0.33	0.35
86	0.23	0.28	0.33	0.35	0.32	0.26	0.32	0.32
87	0.21	0.26	0.30	0.32	0.29	0.23	0.29	0.29
88	0.18	0.23	0.26	0.28	0.26	0.21	0.26	0.26
89	0.16	0.20	0.23	0.25	0.23	0.18	0.23	0.23
90	0.14	0.17	0.20	0.21	0.19	0.15	0.19	0.19
91	0.11	0.14	0.16	0.17	0.16	0.13	0.16	0.16
92	0.09	0.11	0.13	0.14	0.12	0.10	0.12	0.12
93	0.06	0.08	0.09	0.10	0.09	0.07	0.09	0.09
94	0.04	0.05	0.06	0.06	0.06	0.05	0.06	0.06
95	0.02	0.02	0.03	0.03	0.03	0.02	0.03	0.03

Table D-9
Adjusted Projected Savings per AC Unit (kW)
Duration = 3 hours, Re-set = 4°F

Daily Average	Hour Ending						Hour Ending 18 Range	
Temperature (°F)	14	15	16	17	18	19	Low	High
65	0.02	0.03	0.04	0.04	0.04	0.03	0.04	0.04
66	0.04	0.05	0.06	0.06	0.06	0.05	0.05	0.06
67	0.05	0.07	0.08	0.09	0.08	0.07	0.07	0.09
68	0.07	0.10	0.12	0.12	0.11	0.09	0.10	0.12
69	0.10	0.13	0.15	0.16	0.14	0.12	0.13	0.16
70	0.12	0.17	0.19	0.19	0.17	0.15	0.15	0.20
71	0.15	0.20	0.23	0.23	0.21	0.18	0.18	0.23
72	0.18	0.23	0.27	0.27	0.24	0.20	0.22	0.27
73	0.21	0.26	0.30	0.30	0.27	0.23	0.24	0.30
74	0.24	0.30	0.35	0.35	0.31	0.25	0.28	0.35
75	0.27	0.34	0.38	0.40	0.35	0.29	0.31	0.38
76	0.29	0.36	0.42	0.45	0.39	0.32	0.35	0.43
77	0.31	0.39	0.44	0.49	0.42	0.35	0.39	0.47
78	0.32	0.40	0.46	0.51	0.45	0.37	0.41	0.49
79	0.33	0.41	0.48	0.54	0.47	0.38	0.43	0.51
80	0.34	0.43	0.50	0.56	0.49	0.39	0.45	0.52
81	0.35	0.44	0.52	0.57	0.50	0.40	0.46	0.53
82	0.35	0.44	0.52	0.56	0.50	0.40	0.47	0.54
83	0.35	0.44	0.51	0.55	0.50	0.40	0.47	0.52
84	0.34	0.42	0.50	0.53	0.48	0.39	0.45	0.51
85	0.32	0.40	0.47	0.51	0.46	0.37	0.44	0.47
86	0.30	0.38	0.44	0.47	0.43	0.35	0.41	0.43
87	0.27	0.34	0.40	0.43	0.39	0.31	0.38	0.39
88	0.24	0.30	0.35	0.38	0.35	0.28	0.35	0.35
89	0.21	0.26	0.31	0.33	0.30	0.24	0.30	0.30
90	0.18	0.22	0.26	0.28	0.26	0.21	0.26	0.26
91	0.15	0.18	0.21	0.23	0.21	0.17	0.21	0.21
92	0.12	0.14	0.17	0.18	0.16	0.13	0.16	0.16
93	0.08	0.10	0.12	0.13	0.12	0.10	0.12	0.12
94	0.05	0.07	0.08	0.08	0.08	0.06	0.08	0.08
95	0.02	0.03	0.04	0.04	0.03	0.03	0.03	0.03

Table D-10
Adjusted Projected Savings per AC Unit (kW)
Duration = 3 hours, Re-set = 5°F

Daily Average Temperature (°F)	Hour Ending						Hour Ending 18 Range	
	14	15	16	17	18	19	Low	High
65	0.02	0.03	0.04	0.04	0.04	0.03	0.04	0.04
66	0.04	0.05	0.06	0.07	0.06	0.05	0.06	0.07
67	0.06	0.08	0.09	0.10	0.09	0.07	0.08	0.10
68	0.08	0.11	0.13	0.13	0.12	0.10	0.11	0.13
69	0.11	0.15	0.17	0.18	0.15	0.13	0.14	0.18
70	0.14	0.19	0.21	0.22	0.19	0.17	0.17	0.22
71	0.17	0.23	0.26	0.26	0.24	0.20	0.21	0.27
72	0.21	0.27	0.31	0.31	0.28	0.23	0.25	0.31
73	0.24	0.31	0.35	0.35	0.32	0.27	0.29	0.36
74	0.28	0.35	0.40	0.41	0.36	0.30	0.33	0.41
75	0.31	0.40	0.45	0.47	0.41	0.34	0.37	0.45
76	0.34	0.43	0.49	0.52	0.46	0.38	0.41	0.50
77	0.36	0.46	0.53	0.57	0.50	0.41	0.45	0.55
78	0.39	0.48	0.56	0.61	0.54	0.44	0.48	0.59
79	0.40	0.50	0.58	0.65	0.57	0.46	0.52	0.61
80	0.41	0.52	0.60	0.67	0.59	0.48	0.54	0.63
81	0.42	0.53	0.62	0.68	0.60	0.48	0.56	0.64
82	0.42	0.53	0.63	0.68	0.61	0.49	0.57	0.65
83	0.43	0.53	0.63	0.68	0.61	0.49	0.57	0.64
84	0.42	0.52	0.61	0.66	0.59	0.47	0.55	0.62
85	0.40	0.50	0.58	0.62	0.56	0.45	0.54	0.59
86	0.37	0.46	0.54	0.58	0.53	0.42	0.51	0.54
87	0.34	0.42	0.50	0.53	0.49	0.39	0.47	0.49
88	0.30	0.38	0.44	0.47	0.43	0.35	0.43	0.43
89	0.27	0.33	0.38	0.41	0.38	0.30	0.38	0.38
90	0.23	0.28	0.33	0.35	0.32	0.26	0.32	0.32
91	0.18	0.23	0.27	0.29	0.26	0.21	0.26	0.26
92	0.14	0.18	0.21	0.23	0.21	0.16	0.21	0.21
93	0.11	0.13	0.15	0.16	0.15	0.12	0.15	0.15
94	0.07	0.08	0.10	0.10	0.10	0.08	0.10	0.10
95	0.03	0.04	0.04	0.05	0.04	0.03	0.04	0.04

Table D-11
Adjusted Projected Savings per AC Unit (kW)
Duration = 4 hours, Re-set = 1°F

Daily Average	Hour Ending						Hour Ending 18 Range	
Temperature (°F)	14	15	16	17	18	19	Low	High
65	0.01	0.01	0.02	0.02	0.02	0.01	0.01	0.02
66	0.02	0.02	0.02	0.03	0.02	0.02	0.02	0.03
67	0.02	0.03	0.03	0.04	0.03	0.03	0.03	0.03
68	0.03	0.04	0.04	0.04	0.04	0.03	0.03	0.04
69	0.04	0.05	0.05	0.05	0.05	0.04	0.04	0.06
70	0.04	0.05	0.06	0.06	0.06	0.05	0.05	0.06
71	0.05	0.06	0.07	0.07	0.07	0.05	0.06	0.07
72	0.05	0.07	0.08	0.08	0.07	0.06	0.07	0.08
73	0.06	0.08	0.09	0.09	0.08	0.06	0.07	0.09
74	0.07	0.09	0.10	0.11	0.09	0.08	0.08	0.10
75	0.08	0.10	0.11	0.12	0.10	0.09	0.09	0.11
76	0.08	0.10	0.11	0.13	0.11	0.09	0.10	0.13
77	0.08	0.10	0.11	0.13	0.11	0.09	0.11	0.12
78	0.08	0.10	0.12	0.13	0.12	0.09	0.10	0.13
79	0.09	0.11	0.13	0.14	0.13	0.10	0.12	0.13
80	0.09	0.11	0.13	0.14	0.13	0.10	0.12	0.13
81	0.09	0.11	0.13	0.14	0.12	0.10	0.12	0.14
82	0.08	0.10	0.12	0.13	0.12	0.10	0.12	0.13
83	0.08	0.11	0.12	0.13	0.12	0.10	0.11	0.12
84	0.08	0.10	0.11	0.12	0.11	0.09	0.10	0.11
85	0.07	0.09	0.10	0.11	0.10	0.08	0.10	0.10
86	0.06	0.08	0.09	0.10	0.09	0.07	0.09	0.09
87	0.06	0.07	0.08	0.09	0.08	0.06	0.08	0.08
88	0.05	0.06	0.07	0.07	0.07	0.05	0.07	0.07
89	0.04	0.05	0.06	0.06	0.06	0.05	0.06	0.06
90	0.03	0.04	0.05	0.05	0.04	0.04	0.04	0.04
91	0.02	0.03	0.03	0.04	0.03	0.03	0.03	0.03
92	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
93	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table D-12
Adjusted Projected Savings per AC Unit (kW)
Duration = 4 hours, Re-set = 2°F

Daily Average	Hour Ending						Hour Ending 18 Range	
Temperature (°F)	14	15	16	17	18	19	Low	High
65	0.02	0.02	0.02	0.03	0.03	0.02	0.02	0.03
66	0.02	0.03	0.04	0.04	0.04	0.03	0.04	0.04
67	0.04	0.05	0.06	0.06	0.05	0.05	0.05	0.06
68	0.05	0.07	0.08	0.08	0.07	0.06	0.06	0.08
69	0.06	0.09	0.10	0.10	0.08	0.07	0.08	0.10
70	0.08	0.10	0.11	0.11	0.10	0.09	0.09	0.12
71	0.09	0.11	0.13	0.13	0.12	0.10	0.11	0.13
72	0.10	0.13	0.15	0.15	0.13	0.11	0.12	0.15
73	0.11	0.14	0.17	0.17	0.15	0.12	0.13	0.17
74	0.13	0.17	0.19	0.19	0.17	0.14	0.15	0.19
75	0.15	0.18	0.21	0.22	0.19	0.16	0.17	0.21
76	0.15	0.19	0.22	0.24	0.21	0.18	0.19	0.23
77	0.15	0.19	0.22	0.25	0.22	0.18	0.20	0.25
78	0.16	0.20	0.23	0.26	0.22	0.18	0.21	0.25
79	0.16	0.21	0.25	0.27	0.24	0.19	0.21	0.25
80	0.17	0.21	0.25	0.28	0.25	0.20	0.23	0.25
81	0.17	0.21	0.25	0.27	0.24	0.19	0.23	0.26
82	0.17	0.21	0.24	0.26	0.23	0.19	0.23	0.26
83	0.16	0.20	0.24	0.26	0.23	0.19	0.21	0.24
84	0.16	0.19	0.23	0.24	0.22	0.18	0.20	0.22
85	0.14	0.18	0.21	0.22	0.20	0.16	0.19	0.20
86	0.13	0.16	0.18	0.20	0.18	0.14	0.18	0.18
87	0.11	0.14	0.16	0.17	0.16	0.13	0.16	0.16
88	0.10	0.12	0.14	0.15	0.14	0.11	0.14	0.14
89	0.08	0.10	0.11	0.12	0.11	0.09	0.11	0.11
90	0.06	0.08	0.09	0.10	0.09	0.07	0.09	0.09
91	0.05	0.06	0.07	0.07	0.07	0.05	0.07	0.07
92	0.03	0.04	0.05	0.05	0.05	0.04	0.05	0.05
93	0.02	0.02	0.02	0.03	0.02	0.02	0.02	0.02
94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table D-13
Adjusted Projected Savings per AC Unit (kW)
Duration = 4 hours, Re-set = 3°F

Daily Average	Hour Ending						Hour Ending 18 Range	
Temperature (°F)	14	15	16	17	18	19	Low	High
65	0.02	0.03	0.03	0.04	0.03	0.03	0.03	0.04
66	0.03	0.04	0.05	0.05	0.05	0.04	0.05	0.06
67	0.04	0.06	0.07	0.08	0.07	0.06	0.06	0.08
68	0.06	0.08	0.10	0.10	0.09	0.08	0.08	0.10
69	0.08	0.11	0.13	0.13	0.11	0.10	0.10	0.13
70	0.10	0.14	0.15	0.15	0.14	0.12	0.12	0.16
71	0.12	0.16	0.18	0.18	0.17	0.14	0.15	0.19
72	0.14	0.18	0.21	0.21	0.19	0.16	0.17	0.21
73	0.16	0.20	0.24	0.23	0.21	0.17	0.19	0.24
74	0.18	0.23	0.26	0.27	0.23	0.19	0.22	0.27
75	0.20	0.26	0.29	0.31	0.27	0.22	0.24	0.29
76	0.22	0.28	0.32	0.34	0.30	0.25	0.27	0.33
77	0.23	0.28	0.33	0.36	0.32	0.26	0.29	0.34
78	0.23	0.29	0.33	0.37	0.33	0.27	0.30	0.36
79	0.24	0.30	0.35	0.39	0.34	0.28	0.31	0.37
80	0.24	0.31	0.36	0.40	0.35	0.28	0.32	0.37
81	0.25	0.31	0.37	0.40	0.36	0.29	0.33	0.38
82	0.24	0.30	0.36	0.39	0.35	0.28	0.33	0.37
83	0.24	0.30	0.35	0.38	0.34	0.27	0.32	0.36
84	0.23	0.28	0.33	0.36	0.32	0.26	0.30	0.33
85	0.21	0.26	0.31	0.33	0.30	0.24	0.28	0.30
86	0.19	0.24	0.28	0.30	0.27	0.22	0.26	0.27
87	0.17	0.21	0.24	0.26	0.24	0.19	0.24	0.24
88	0.14	0.18	0.21	0.22	0.20	0.16	0.20	0.20
89	0.12	0.15	0.17	0.19	0.17	0.14	0.17	0.17
90	0.09	0.12	0.14	0.15	0.13	0.11	0.13	0.13
91	0.07	0.09	0.10	0.11	0.10	0.08	0.10	0.10
92	0.05	0.06	0.07	0.07	0.07	0.05	0.07	0.07
93	0.03	0.03	0.04	0.04	0.04	0.03	0.04	0.04
94	0.00	0.01	0.01	0.01	0.01	0.00	0.01	0.01
95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table D-14
Adjusted Projected Savings per AC Unit (kW)
Duration = 4 hours, Re-set = 4°F

Daily Average Temperature (°F)	Hour Ending						Hour Ending 18 Range	
	14	15	16	17	18	19	Low	High
65	0.02	0.03	0.04	0.04	0.04	0.03	0.03	0.04
66	0.04	0.05	0.05	0.06	0.06	0.05	0.05	0.06
67	0.05	0.07	0.08	0.09	0.08	0.07	0.07	0.09
68	0.07	0.10	0.11	0.12	0.10	0.09	0.10	0.12
69	0.10	0.13	0.15	0.16	0.14	0.12	0.12	0.16
70	0.12	0.16	0.19	0.19	0.17	0.15	0.15	0.19
71	0.15	0.20	0.22	0.22	0.20	0.17	0.18	0.23
72	0.18	0.23	0.26	0.26	0.23	0.20	0.21	0.26
73	0.20	0.25	0.29	0.29	0.26	0.22	0.23	0.29
74	0.23	0.29	0.33	0.34	0.30	0.24	0.27	0.33
75	0.25	0.32	0.37	0.38	0.33	0.28	0.30	0.37
76	0.28	0.35	0.40	0.42	0.37	0.31	0.33	0.41
77	0.29	0.36	0.42	0.46	0.40	0.33	0.37	0.44
78	0.30	0.37	0.43	0.48	0.42	0.34	0.38	0.46
79	0.31	0.38	0.45	0.50	0.44	0.36	0.40	0.48
80	0.31	0.39	0.46	0.51	0.45	0.36	0.41	0.48
81	0.32	0.40	0.47	0.52	0.46	0.37	0.42	0.49
82	0.32	0.40	0.47	0.51	0.45	0.36	0.43	0.48
83	0.31	0.39	0.46	0.49	0.44	0.35	0.41	0.47
84	0.30	0.37	0.43	0.47	0.42	0.34	0.40	0.44
85	0.28	0.34	0.40	0.43	0.39	0.32	0.37	0.40
86	0.25	0.31	0.37	0.39	0.36	0.29	0.34	0.36
87	0.22	0.28	0.32	0.35	0.32	0.25	0.31	0.32
88	0.19	0.24	0.28	0.30	0.27	0.22	0.27	0.27
89	0.16	0.20	0.23	0.25	0.23	0.18	0.23	0.23
90	0.13	0.16	0.18	0.20	0.18	0.14	0.18	0.18
91	0.09	0.12	0.14	0.15	0.13	0.11	0.13	0.13
92	0.06	0.08	0.09	0.10	0.09	0.07	0.09	0.09
93	0.03	0.04	0.05	0.05	0.05	0.04	0.05	0.05
94	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table D-15
Adjusted Projected Savings per AC Unit (kW)
Duration = 4 hours, Re-set = 5°F

Daily Average Temperature (°F)	Hour Ending						Hour Ending 18 Range	
	14	15	16	17	18	19	Low	High
65	0.02	0.03	0.04	0.04	0.04	0.03	0.04	0.04
66	0.04	0.05	0.06	0.07	0.06	0.05	0.06	0.07
67	0.06	0.07	0.09	0.10	0.09	0.07	0.08	0.10
68	0.08	0.11	0.12	0.13	0.11	0.10	0.10	0.13
69	0.11	0.14	0.17	0.17	0.15	0.13	0.14	0.18
70	0.14	0.18	0.21	0.21	0.19	0.16	0.17	0.22
71	0.17	0.22	0.25	0.26	0.23	0.20	0.20	0.26
72	0.20	0.26	0.30	0.30	0.27	0.23	0.24	0.30
73	0.23	0.30	0.34	0.34	0.31	0.26	0.28	0.34
74	0.27	0.34	0.39	0.39	0.35	0.29	0.31	0.39
75	0.30	0.38	0.43	0.45	0.39	0.33	0.35	0.43
76	0.32	0.41	0.47	0.50	0.43	0.36	0.39	0.48
77	0.34	0.43	0.50	0.54	0.47	0.39	0.43	0.52
78	0.36	0.45	0.52	0.58	0.50	0.41	0.45	0.55
79	0.37	0.47	0.54	0.60	0.53	0.43	0.48	0.57
80	0.38	0.48	0.56	0.62	0.54	0.44	0.50	0.58
81	0.38	0.48	0.56	0.62	0.55	0.44	0.51	0.59
82	0.38	0.48	0.56	0.62	0.55	0.44	0.51	0.58
83	0.38	0.47	0.56	0.60	0.54	0.43	0.50	0.57
84	0.36	0.45	0.53	0.57	0.52	0.41	0.48	0.54
85	0.34	0.42	0.50	0.53	0.48	0.39	0.46	0.50
86	0.31	0.39	0.45	0.49	0.44	0.35	0.42	0.45
87	0.28	0.34	0.40	0.43	0.40	0.32	0.38	0.40
88	0.24	0.30	0.35	0.37	0.34	0.27	0.33	0.34
89	0.20	0.25	0.29	0.31	0.28	0.23	0.28	0.28
90	0.16	0.20	0.23	0.25	0.22	0.18	0.22	0.22
91	0.12	0.15	0.17	0.18	0.17	0.13	0.17	0.17
92	0.08	0.10	0.11	0.12	0.11	0.09	0.11	0.11
93	0.04	0.05	0.06	0.07	0.06	0.05	0.06	0.06
94	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table D-16
Adjusted Projected Savings per AC Unit (kW)
Duration = 5 hours, Re-set = 1°F

Daily Average Temperature (°F)	Hour Ending						Hour Ending 18 Range	
	14	15	16	17	18	19	Low	High
65	0.01	0.01	0.01	0.02	0.02	0.01	0.01	0.02
66	0.02	0.02	0.02	0.03	0.02	0.02	0.02	0.03
67	0.02	0.03	0.03	0.04	0.03	0.03	0.03	0.03
68	0.03	0.04	0.04	0.04	0.03	0.03	0.03	0.04
69	0.04	0.05	0.05	0.05	0.05	0.04	0.04	0.06
70	0.04	0.05	0.06	0.06	0.06	0.05	0.05	0.06
71	0.05	0.06	0.07	0.07	0.06	0.05	0.06	0.07
72	0.05	0.07	0.08	0.08	0.07	0.06	0.06	0.08
73	0.06	0.08	0.09	0.09	0.07	0.06	0.07	0.09
74	0.07	0.09	0.10	0.11	0.09	0.08	0.08	0.10
75	0.07	0.09	0.11	0.12	0.10	0.08	0.09	0.10
76	0.08	0.09	0.11	0.12	0.11	0.09	0.10	0.12
77	0.08	0.10	0.11	0.12	0.11	0.09	0.10	0.12
78	0.08	0.10	0.12	0.13	0.11	0.09	0.10	0.12
79	0.08	0.10	0.13	0.14	0.12	0.10	0.11	0.13
80	0.08	0.11	0.12	0.13	0.12	0.10	0.11	0.12
81	0.08	0.10	0.12	0.13	0.12	0.09	0.11	0.13
82	0.08	0.10	0.12	0.12	0.11	0.09	0.11	0.12
83	0.08	0.10	0.12	0.12	0.11	0.09	0.10	0.11
84	0.07	0.09	0.10	0.11	0.10	0.08	0.10	0.10
85	0.06	0.08	0.09	0.10	0.09	0.07	0.09	0.09
86	0.06	0.07	0.08	0.09	0.08	0.07	0.08	0.08
87	0.05	0.06	0.07	0.08	0.07	0.06	0.07	0.07
88	0.04	0.05	0.06	0.06	0.06	0.05	0.06	0.06
89	0.03	0.04	0.05	0.05	0.05	0.04	0.05	0.05
90	0.03	0.03	0.04	0.04	0.04	0.03	0.04	0.04
91	0.02	0.02	0.03	0.03	0.02	0.02	0.02	0.02
92	0.01	0.01	0.01	0.02	0.01	0.01	0.01	0.01
93	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table D-17
Adjusted Projected Savings per AC Unit (kW)
Duration = 5 hours, Re-set = 2°F

Daily Average	Hour Ending						Hour Ending 18 Range	
Temperature (°F)	14	15	16	17	18	19	Low	High
65	0.01	0.02	0.02	0.03	0.03	0.02	0.02	0.03
66	0.02	0.03	0.04	0.04	0.04	0.03	0.04	0.04
67	0.03	0.05	0.06	0.06	0.05	0.05	0.05	0.06
68	0.05	0.07	0.08	0.08	0.06	0.06	0.06	0.08
69	0.06	0.08	0.09	0.09	0.08	0.07	0.07	0.10
70	0.07	0.10	0.11	0.11	0.10	0.09	0.09	0.11
71	0.09	0.11	0.13	0.13	0.12	0.10	0.10	0.13
72	0.10	0.13	0.15	0.15	0.13	0.11	0.12	0.15
73	0.11	0.14	0.16	0.16	0.14	0.12	0.13	0.16
74	0.13	0.16	0.18	0.19	0.16	0.14	0.15	0.19
75	0.14	0.18	0.20	0.22	0.19	0.16	0.17	0.20
76	0.15	0.19	0.21	0.23	0.21	0.17	0.18	0.22
77	0.15	0.19	0.22	0.24	0.21	0.17	0.20	0.24
78	0.15	0.19	0.22	0.25	0.22	0.17	0.20	0.24
79	0.16	0.20	0.24	0.26	0.23	0.18	0.21	0.24
80	0.16	0.20	0.24	0.27	0.24	0.19	0.22	0.24
81	0.16	0.20	0.24	0.26	0.23	0.18	0.22	0.24
82	0.16	0.20	0.23	0.25	0.22	0.18	0.21	0.24
83	0.15	0.19	0.22	0.24	0.22	0.17	0.20	0.23
84	0.14	0.18	0.21	0.22	0.21	0.16	0.19	0.21
85	0.13	0.16	0.19	0.20	0.18	0.15	0.18	0.18
86	0.11	0.14	0.17	0.18	0.16	0.13	0.16	0.16
87	0.10	0.12	0.14	0.15	0.14	0.11	0.14	0.14
88	0.08	0.10	0.12	0.13	0.12	0.09	0.12	0.12
89	0.07	0.08	0.10	0.10	0.09	0.08	0.09	0.09
90	0.05	0.06	0.07	0.08	0.07	0.06	0.07	0.07
91	0.03	0.04	0.05	0.05	0.05	0.04	0.05	0.05
92	0.02	0.02	0.03	0.03	0.03	0.02	0.03	0.03
93	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table D-18
Adjusted Projected Savings per AC Unit (kW)
Duration = 5 hours, Re-set = 3°F

Daily Average Temperature (°F)	Hour Ending						Hour Ending 18 Range	
	14	15	16	17	18	19	Low	High
65	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.04
66	0.03	0.04	0.05	0.05	0.05	0.04	0.05	0.05
67	0.04	0.06	0.07	0.08	0.07	0.06	0.06	0.08
68	0.06	0.08	0.10	0.10	0.09	0.08	0.08	0.10
69	0.08	0.11	0.13	0.13	0.11	0.10	0.10	0.13
70	0.10	0.14	0.15	0.15	0.14	0.12	0.12	0.16
71	0.12	0.16	0.18	0.18	0.16	0.14	0.15	0.18
72	0.14	0.18	0.20	0.20	0.19	0.15	0.17	0.20
73	0.16	0.20	0.23	0.23	0.20	0.17	0.19	0.23
74	0.18	0.23	0.26	0.26	0.23	0.19	0.21	0.26
75	0.20	0.25	0.29	0.30	0.26	0.22	0.23	0.29
76	0.21	0.27	0.31	0.33	0.29	0.24	0.26	0.32
77	0.22	0.27	0.32	0.35	0.31	0.25	0.28	0.33
78	0.22	0.28	0.32	0.36	0.32	0.26	0.29	0.35
79	0.23	0.29	0.34	0.37	0.33	0.27	0.30	0.35
80	0.23	0.29	0.35	0.38	0.34	0.27	0.31	0.35
81	0.23	0.30	0.35	0.38	0.34	0.27	0.32	0.36
82	0.23	0.29	0.34	0.36	0.33	0.26	0.31	0.35
83	0.22	0.28	0.33	0.35	0.32	0.25	0.30	0.34
84	0.21	0.26	0.31	0.33	0.30	0.24	0.28	0.31
85	0.19	0.24	0.28	0.30	0.28	0.22	0.26	0.28
86	0.17	0.21	0.25	0.27	0.24	0.20	0.24	0.24
87	0.15	0.18	0.21	0.23	0.21	0.17	0.21	0.21
88	0.12	0.15	0.18	0.19	0.18	0.14	0.18	0.18
89	0.10	0.12	0.14	0.15	0.14	0.11	0.14	0.14
90	0.08	0.09	0.11	0.12	0.11	0.09	0.11	0.11
91	0.05	0.06	0.08	0.08	0.07	0.06	0.07	0.07
92	0.03	0.04	0.04	0.05	0.04	0.03	0.04	0.04
93	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table D-19
Adjusted Projected Savings per AC Unit (kW)
Duration = 5 hours, Re-set = 4°F

Daily Average	Hour Ending						Hour Ending 18 Range	
Temperature (°F)	14	15	16	17	18	19	Low	High
65	0.02	0.03	0.04	0.04	0.04	0.03	0.03	0.04
66	0.04	0.05	0.05	0.06	0.06	0.05	0.05	0.06
67	0.05	0.07	0.08	0.09	0.08	0.07	0.07	0.09
68	0.07	0.10	0.11	0.12	0.10	0.09	0.09	0.12
69	0.10	0.13	0.15	0.15	0.13	0.12	0.12	0.16
70	0.12	0.16	0.18	0.19	0.17	0.14	0.15	0.19
71	0.15	0.19	0.22	0.22	0.20	0.17	0.18	0.22
72	0.17	0.22	0.25	0.25	0.23	0.19	0.21	0.26
73	0.20	0.25	0.28	0.28	0.26	0.21	0.23	0.29
74	0.22	0.28	0.32	0.33	0.29	0.24	0.26	0.33
75	0.25	0.31	0.36	0.37	0.32	0.27	0.29	0.36
76	0.27	0.34	0.39	0.41	0.36	0.30	0.32	0.40
77	0.28	0.35	0.41	0.44	0.39	0.32	0.35	0.43
78	0.29	0.36	0.42	0.46	0.41	0.33	0.37	0.44
79	0.29	0.37	0.43	0.48	0.42	0.34	0.39	0.46
80	0.30	0.38	0.44	0.49	0.43	0.35	0.40	0.45
81	0.30	0.38	0.45	0.49	0.43	0.35	0.40	0.46
82	0.30	0.37	0.44	0.48	0.43	0.34	0.40	0.46
83	0.29	0.36	0.43	0.46	0.41	0.33	0.39	0.44
84	0.28	0.34	0.40	0.43	0.39	0.31	0.37	0.41
85	0.25	0.32	0.37	0.40	0.36	0.29	0.34	0.37
86	0.23	0.28	0.33	0.36	0.32	0.26	0.31	0.33
87	0.20	0.24	0.29	0.31	0.28	0.22	0.28	0.28
88	0.16	0.20	0.24	0.26	0.23	0.19	0.23	0.23
89	0.13	0.16	0.19	0.21	0.19	0.15	0.19	0.19
90	0.10	0.12	0.15	0.16	0.14	0.11	0.14	0.14
91	0.07	0.09	0.10	0.11	0.10	0.08	0.10	0.10
92	0.04	0.05	0.06	0.06	0.06	0.04	0.06	0.06
93	0.01	0.01	0.02	0.02	0.02	0.01	0.02	0.02
94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table D-20
Adjusted Projected Savings per AC Unit (kW)
Duration = 5 hours, Re-set = 5°F

Daily Average Temperature (°F)	Hour Ending						Hour Ending 18 Range	
	14	15	16	17	18	19	Low	High
65	0.02	0.03	0.04	0.04	0.04	0.03	0.04	0.04
66	0.04	0.05	0.06	0.06	0.06	0.05	0.06	0.07
67	0.05	0.07	0.09	0.10	0.09	0.07	0.08	0.10
68	0.08	0.10	0.12	0.13	0.11	0.10	0.10	0.13
69	0.10	0.14	0.16	0.17	0.15	0.13	0.14	0.17
70	0.13	0.18	0.20	0.21	0.19	0.16	0.17	0.21
71	0.17	0.22	0.25	0.25	0.23	0.19	0.20	0.26
72	0.20	0.26	0.29	0.29	0.26	0.22	0.24	0.30
73	0.23	0.29	0.33	0.33	0.30	0.25	0.27	0.34
74	0.26	0.33	0.38	0.38	0.34	0.28	0.31	0.38
75	0.29	0.37	0.42	0.44	0.38	0.32	0.34	0.42
76	0.32	0.40	0.46	0.48	0.42	0.35	0.38	0.47
77	0.33	0.42	0.48	0.52	0.45	0.38	0.41	0.50
78	0.35	0.44	0.50	0.56	0.48	0.40	0.44	0.53
79	0.36	0.45	0.52	0.58	0.51	0.42	0.46	0.55
80	0.36	0.45	0.53	0.59	0.52	0.42	0.48	0.56
81	0.36	0.46	0.54	0.59	0.52	0.42	0.48	0.56
82	0.36	0.45	0.53	0.58	0.52	0.41	0.48	0.55
83	0.35	0.44	0.52	0.56	0.51	0.41	0.47	0.53
84	0.34	0.42	0.49	0.53	0.48	0.38	0.45	0.50
85	0.31	0.39	0.45	0.49	0.44	0.36	0.42	0.46
86	0.28	0.35	0.41	0.44	0.40	0.32	0.38	0.41
87	0.25	0.31	0.36	0.38	0.35	0.28	0.34	0.35
88	0.21	0.26	0.30	0.32	0.29	0.23	0.29	0.29
89	0.17	0.21	0.24	0.26	0.24	0.19	0.24	0.24
90	0.13	0.16	0.18	0.20	0.18	0.14	0.18	0.18
91	0.09	0.11	0.13	0.14	0.12	0.10	0.12	0.12
92	0.05	0.06	0.07	0.08	0.07	0.06	0.07	0.07
93	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02
94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00