FREEMAN, SULLIVAN & CO.

A MEMBER OF THE FSC GROUP

Pacific Gas & Electric Company's 2012 Value of Service Study

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1 Executive Summary

Freeman, Sullivan & Co. (FSC) was retained by Pacific Gas & Electric Company (PG&E) to conduct its 2012 Value of Service (VOS) study – research to estimate the costs customers incur during power outages. This study was conducted as a result of a directive by the California Public Utilities Commission (CPUC) for PG&E to carry out a VOS study. This comprehensive research project was designed to collect detailed outage cost information from all 4 of PG&E's customer classes – residential, small & medium business (SMB), large business and agricultural. In this report, the methodology and results of the study are summarized. The primary objectives of the 2012 VOS study were to:

- Estimate 2012 outage costs by customer class and region;
- Determine how costs vary by outage timing for each customer class;
- Compare 2012 outage cost estimates by customer class to those of previous studies; and
- Understand the level of reliability that is considered acceptable within each customer class.

The VOS analyses are based on survey data collected in 4 separate surveys (one for each customer class) conducted during late 2011 and early 2012. The responses were used to estimate the value of service reliability for each customer segment, using procedures that have been developed and validated over the past 25 years by the Electric Power Research Institute (EPRI) and other parties.[1]

Although the basic methodology is similar to previous work, the 2012 PG&E VOS study featured several noteworthy methodological improvements. These methodological improvements include:

- **Dynamic survey instrument design:** In the 2012 survey instrument, each respondent was randomly assigned to 1 of 24 different outage onset times (for 24 hours of the day) and reported costs for a weekend scenario with a randomly assigned outage duration. This design produced the data necessary for understanding how outage costs vary across different times of the day and week, for outages from 5 minutes to 24 hours. This dynamic survey data was also able to produce an estimate of the average outage cost across all time periods, as opposed to focusing on an individual time period. In the 2005 PG&E VOS study and many other prior studies, outage scenarios were primarily limited to summer weekday afternoons, which was useful for generation planning, but not directly applicable to transmission and distribution planning.
- **Oversampling in Bay Area:** During the sample design process, FSC analyzed how aggregate economic output per unit of electricity use varied across PG&E's service territory. This analysis found that outage costs are likely to be significantly higher in the Bay Area than in other parts of PG&E's service territory. Therefore, the sample design had specific quotas for the number of Bay Area and non-Bay Area customers and included an oversampling of non-residential customers in the Bay Area. With this approach, the results were able to account for differences between Bay Area and non-Bay Area customers.
- **Optimized sample design:** The sample design took advantage of information from the 2005 PG&E VOS study to optimally define the number of usage strata and boundaries for the usage strata. Taking advantage of previous results allowed FSC to determine the sample stratification method that minimized the variance in the estimated outage cost, which maximized the precision of the 2012 estimates.
- **Improved customer damage functions:** Customer damage functions are statistical models that predict how outage costs vary across customers, outage duration and other outage characteristics. In the 2005 study, a Tobit regression model was used to estimate the

[1] Sullivan, M.J., and D. Keane (1995). *Outage Cost Estimation Guidebook*. Report no. TR-106082. Palo Alto, CA: EPRI.

- customer damage functions. However, a 2009 meta-analysis by Lawrence Berkeley National Laboratory showed that a two-part econometric model is more appropriate for modeling outage cost data.[2] In this study, FSC applied the two-part econometric model to this dynamic survey data to develop estimates for how outage costs vary by time of day and week for each customer class.
- **Customized cost per unserved kWh estimates:** To develop the cost per unserved kWh estimates, it is necessary to produce a load ratio that estimates the relative amount of unserved electricity for each outage scenario and respondent. Previous studies would simply apply the load factor (ratio of average kW to peak kW) for each customer class because the outage scenarios were primarily focused on peaking periods. In this study, the cost per unserved kWh estimates were customized to each scenario (based on outage timing) and each respondent (based on rate profile).

With the methodological improvements in this study, the 2012 results can be directly applied to many different types of utility investments at the generation, transmission and distribution level.[3]

1.1 Response to Survey

Table 1-1 describes the total number of completed surveys by region and customer class. The total number of completed surveys varied by customer class and was roughly proportional to the size of the underlying populations. With over 1,000 completed surveys each, the relatively populous residential and SMB customer classes had the largest number of participants in the study. The smaller agricultural and large business segments had 538 and 210 respondents, respectively. With the oversampling of non-residential customers in the Bay Area, a majority of SMB and large business respondents were from that region. Considering that the non-Bay Area region has many more agricultural customers, the oversampling generated many more Bay Area respondents that there otherwise would have been, but still far fewer than in the non-Bay Area region.

Table 1-1:
Total Number of Completed Surveys by Region and Customer Class

Region	Residential	SMB	Large Business	Agricultural
Bay Area	491	637	119	125
Non-Bay Area	576	447	91	413
Overall	**1,067**	**1,084**	**210**	**538**

1.2 2012 Outage Cost Estimates

Table 1-2 provides the cost per outage event estimates by customer class. Cost per outage event is the average cost per customer resulting from each outage duration. Given the dynamic survey instrument design, these values represent the average outage cost across all time periods. For a 1-hour outage, large business customers experience the highest cost ($449,655) and residential customers experience the lowest cost ($11.89). Even though SMB and agricultural respondents had

[2] Sullivan, M.J., M. Mercurio and J. Schellenberg (2009). *Estimated Value of Service Reliability for Electric Utility Customers in the United States*. Lawrence Berkeley National Laboratory Report No. LBNL-2132E.

[3] Sullivan, M.J. and J. Schellenberg (2011). *Evaluating Smart Grid Reliability Benefits for Illinois*. National Association of Regulatory Utility Commissioners.

roughly the same average usage, the SMB cost of $1,848.8 for a 1-hour outage is 4.1 times higher than the agricultural cost ($453.5). Between regions, the differences in cost per outage event are stark. Bay Area cost per event is higher than in the non-Bay Area region for every outage duration among residential, SMB and large business customers. For agricultural customers, Bay Area cost per event is higher than in the non-Bay Area region for all outage durations over 1 hour. This result underscores the importance of having segmented the sample among these two regions.

For large business customers in particular, a small subset of Bay Area customers with extremely high outage costs drives much of the difference between regions. These high outage costs must be understood within the context of their level of reliability. Many of these Bay Area large business customers are accustomed to a very high level of reliability and rarely experience sustained power interruptions, so even a 5-minute outage would impose extremely high costs. Considering that these customers are significantly less likely to experience transmission or distribution related power interruptions, it can be argued that their costs should be excluded from many transmission and distribution planning applications. Therefore, Appendix D provides the 2012 large business outage cost estimates by level of service reliability. For transmission and distribution planning applications, FSC recommends applying the results segmented by level of reliability as opposed to region.

Table 1-2:
2012 Cost per Outage Event Estimates by Region and Customer Class

Region	Outage Duration	Residential ($/Event)	SMB ($/Event)	Large Business ($/Event)	Agricultural ($/Event)
Bay Area	5 minutes	$8.18	$585.2	$761,784	$124.1
	1 hour	$13.22	$2,679.4	$861,359	$299.3
	4 hours	$19.59	$6,607.7	$1,073,743	$2,512.2
	8 hours	$26.63	$16,463.6	$1,080,310	$4,866.9
	24 hours	$37.83	$33,780.9	$2,252,293	$8,392.1
Non-Bay Area	5 minutes	$6.96	$159.0	$24,308	$147.5
	1 hour	$10.71	$973.9	$54,970	$461.6
	4 hours	$14.89	$2,761.1	$113,746	$1,201.5
	8 hours	$19.79	$4,435.0	$147,383	$2,496.6
	24 hours	$26.03	$8,514.5	$615,402	$5,763.9
All	5 minutes	$7.41	$379.8	$454,675	$146.1
	1 hour	$11.89	$1,848.8	$449,655	$453.5
	4 hours	$16.82	$4,774.3	$596,675	$1,230.7
	8 hours	$22.89	$10,568.7	$617,196	$2,549.4
	24 hours	$31.67	$21,339.4	$1,472,497	$5,842.4

Figure 1-1 shows cost per average kW by customer class. Cost per average kW is the cost per outage event normalized by average customer demand among respondents. This metric is useful for comparing outage costs across segments because it is normalized by customer demand. For a 1-hour outage, residential customers have the lowest cost per average kW ($14.86), followed by agricultural customers ($52.1) and SMB customers ($205.2). The relative order of cost per average kW for these

3 customer classes is consistent across all outage durations. Large business customers have the highest cost per average kW for outages of 5 minutes and 1 hour. For outages of 4 hours or more, large business cost per average kW is lower than that of the SMB segment. In fact, SMB customers experience the largest increase in costs as outage duration increases. From 5 minutes to 24 hours, SMB cost per average kW increases nearly $100 per hour, compared to around $30 per hour among large business and agricultural customers and a little over $1 per hour for residential customers. This result suggests that SMB customers have relatively few options for mitigating costs as outage duration increases.

Figure 1-1:
2012 Cost per Average kW Estimates by Customer Class

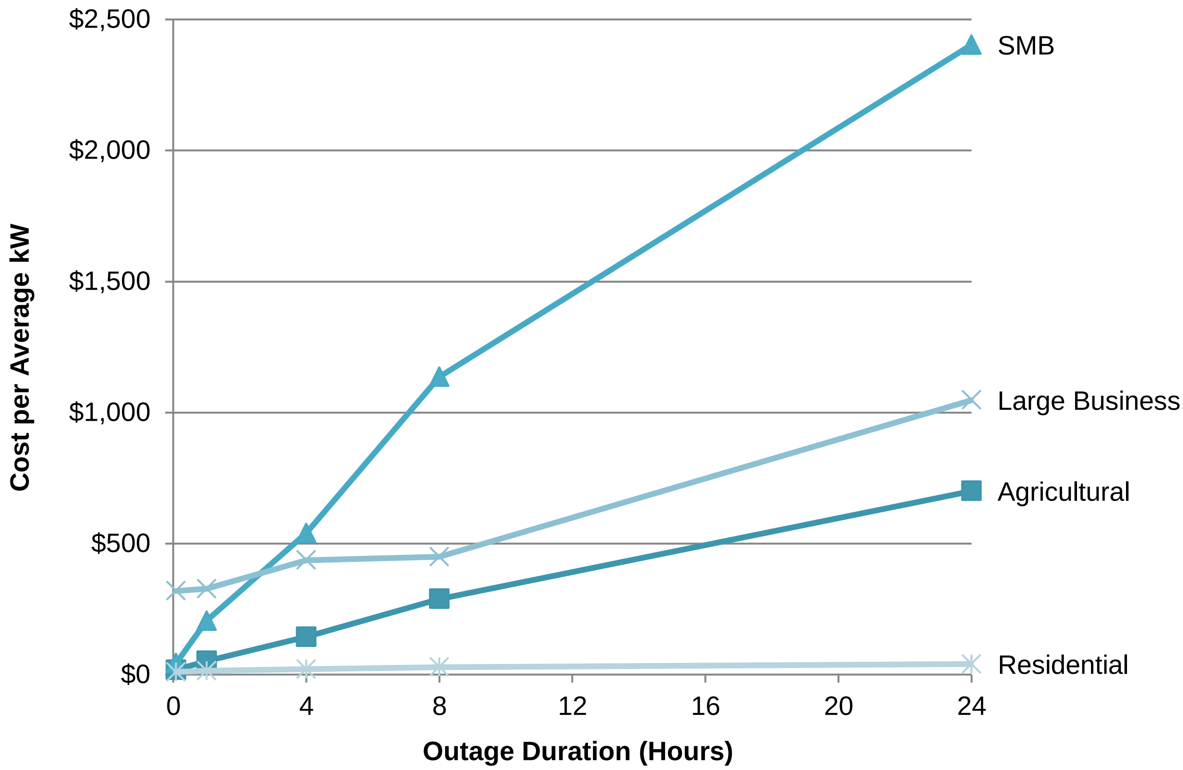


Table 1-3 summarizes cost per average kW by customer class, disaggregated by region. Between regions, the outage cost differences are equally stark when normalizing by respondent demand because average kW is similar in the two regions for each customer class. As in the cost per outage event estimates, Bay Area cost per average kW is higher than in the non-Bay Area region for every outage duration among residential, SMB and large business customers. For agricultural customers, Bay Area cost per average kW is higher than in the non-Bay Area region for all outage durations over 1 hour.

Table 1-3:
2012 Cost per Average kW Estimates by Region and Customer Class

Region	Outage Duration	Residential ($/kW)	SMB ($/kW)	Large Business ($/kW)	Agricultural ($/kW)
Bay Area	5 minutes	$11.86	$62.1	$547.5	$12.8
	1 hour	$18.62	$272.0	$624.7	$44.4
	4 hours	$27.59	$706.0	$774.6	$356.8
	8 hours	$37.51	$1,560.5	$771.0	$682.6
	24 hours	$54.04	$3,482.6	$1,663.5	$1,143.3
Non-Bay Area	5 minutes	$8.39	$19.8	$17.0	$18.2
	1 hour	$12.17	$121.9	$40.7	$52.5
	4 hours	$16.54	$339.2	$85.6	$138.1
	8 hours	$21.99	$557.9	$110.1	$281.8
	24 hours	$29.58	$1,073.7	$443.4	$686.2
All	5 minutes	$9.75	$43.3	$319.3	$18.1
	1 hour	$14.86	$205.2	$327.4	$52.1
	4 hours	$21.03	$540.1	$436.9	$143.9
	8 hours	$28.61	$1,136.4	$449.7	$288.7
	24 hours	$40.09	$2,403.1	$1,047.5	$700.5

Table 1-4 provides the cost per unserved kWh estimates by customer class. Cost per unserved kWh is the cost per outage event normalized by the expected amount of unserved kWh for each outage scenario. This metric is useful because it can be readily used in planning applications, for which the amount of unserved kWh as a result of a given outage is commonly available. At 5-minutes, cost per unserved kWh is at its maximum for each region and customer class because the expected amount of unserved kWh (the denominator of the equation) is very low for a short-duration outage. As duration increases, cost per unserved kWh decreases precipitously because unserved kWh increases linearly with the number of hours while cost per outage event increases at a decreasing rate. Between regions, the differences in cost per unserved kWh show the same trend as in the cost per outage event and cost per average kW estimates where the Bay Area cost is higher for all but the 5-minute and 1-hour agricultural estimates.

Cost per unserved kWh is also interesting because it directly provides an "apples-to-apples" comparison of how customers value electric service versus what they pay for electric service. For all 4 customer classes and all outage durations, customers place a substantially higher value on an unserved kWh than what they would have paid if that electricity had been delivered. Even a 24-hour SMB outage for which hundreds of kWh are unserved on average, SMB customers value lost electric service at $99.7 per unserved kWh. Residential customers experience an outage cost of $5.08 per unserved kWh for a 4-hour outage and $1.67 per kWh for a 24-hour outage, which are clearly lower than the other customer classes, but still substantially higher than what they pay per kWh.

Table 1-4:
2012 Cost per Unserved kWh Estimates by Region and Customer Class

Region	Outage Duration	Residential ($/kWh)	SMB ($/kWh)	Large Business ($/kWh)	Agricultural ($/kWh)
Bay Area	5 minutes	$136.33	$713.7	$6,486.6	$144.3
	1 hour	$18.89	$261.4	$609.7	$42.5
	4 hours	$6.73	$168.3	$189.9	$89.5
	8 hours	$4.56	$192.4	$94.8	$84.6
	24 hours	$2.24	$144.5	$69.1	$48.1
Non-Bay Area	5 minutes	$99.43	$227.2	$201.5	$207.8
	1 hour	$11.77	$114.7	$39.4	$50.7
	4 hours	$4.00	$79.3	$21.2	$34.2
	8 hours	$2.65	$66.5	$13.7	$35.0
	24 hours	$1.23	$44.5	$18.5	$28.2
All	5 minutes	$123.50	$493.3	$3,769.8	$205.7
	1 hour	$14.86	$195.6	$318.5	$50.3
	4 hours	$5.08	$127.5	$107.5	$35.6
	8 hours	$3.44	$138.4	$55.6	$35.9
	24 hours	$1.67	$99.7	$43.7	$28.8

1.3 Impact of Outage Timing

As a result of the dynamic survey design, the 2012 study provided useful information on how outage costs vary across different times of the day and week. For the residential and SMB analyses on the impact of outage timing, onset times were aggregated into 4 key time periods with distinct cost per outage event. These time periods were:

- Morning (7 AM to 11 AM);
- Afternoon (12 PM to 5 PM);
- Evening (6 PM to 9 PM); and
- Night (10 PM to 6 AM).

With fewer observations in the large business and agricultural segments, onset times were aggregated into 2 key time periods because the analysis could not identify clear trends within the more granular time periods used for residential and SMB customers. The 2 key time periods for large business and agricultural customers were:

- Morning and Afternoon (7 AM to 5 PM); and
- Evening and Night (6 PM to 6 AM).

These groups of onset times were further divided among weekdays and weekends for the residential, SMB and agricultural customer classes. In the large business analysis of the impact of outage timing, the onset times were not further divided by day of week because this variable did not have a significant effect for large business customers.

Figure 1-2 provides the weekday relative cost per outage event estimates and Figure 1-3 provides the weekend estimates, which were derived from the customer damage functions described in Appendix B. If a planning application requires an adjustment of outage costs that accounts for onset time, these relative values can be applied to each outage cost estimate in Section 1.2 (referred to as the "base value"). As shown in the figure, outage costs for SMB customers are the most sensitive to onset time, varying from 82.5% lower than the base value on a weekend evening to 85.5% higher on a weekday morning. SMB outages on weekday mornings have the highest percentage increase because these outages likely start and end during normal business hours, potentially disrupting an entire day of work. The only weekday SMB outages that have lower costs than the base value are those with an evening onset time because these outages begin after normal business hours and likely end before business resumes the next day. Although some SMB customers such as retail stores likely have higher costs on a weekend day, SMB is the only customer class that has lower relative outage costs for all weekend onset times. Considering that SMB outage costs vary substantially depending on the onset time, it is important that planning applications apply these relative values.

Figure 1-2:
Relative Cost per Outage Event Estimates by Onset Time and Customer Class – Weekdays

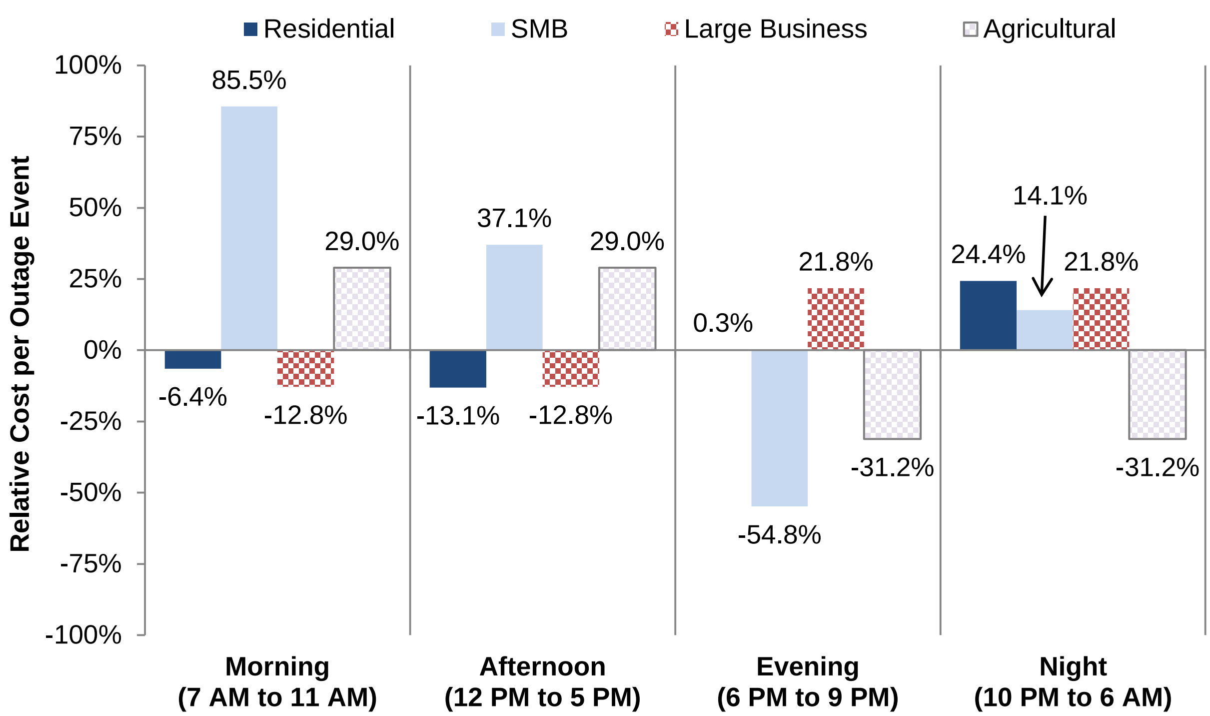
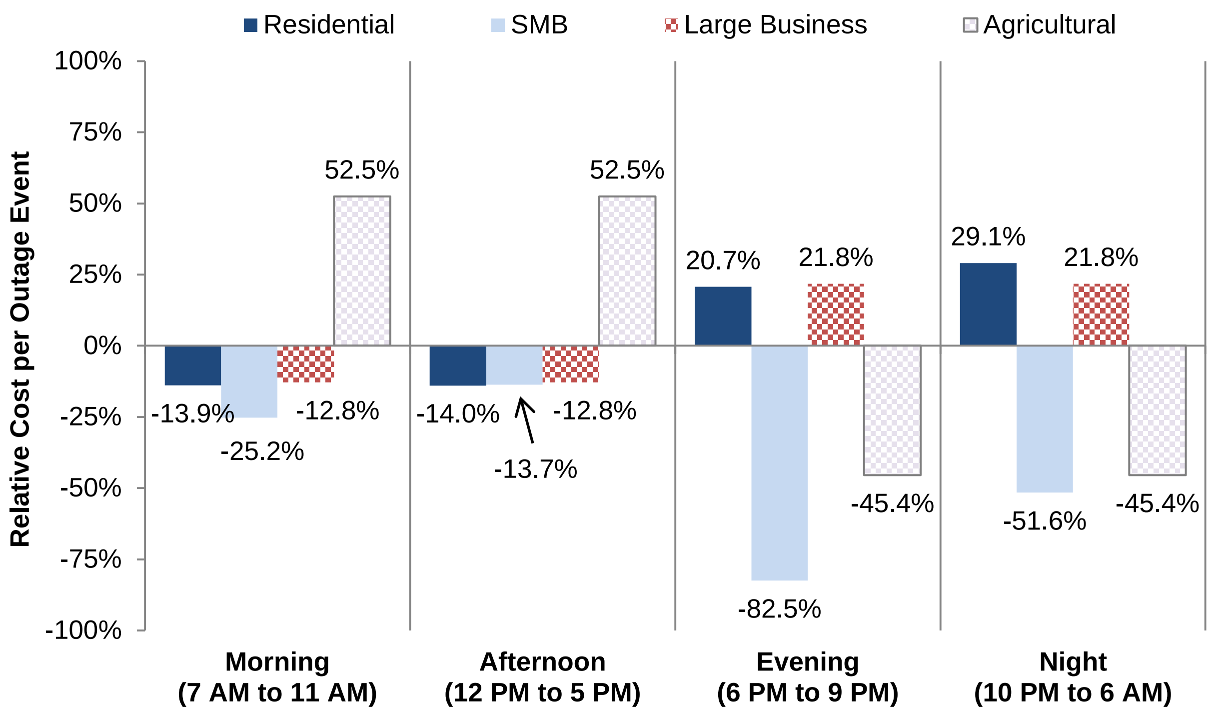


Figure 1-3:
Relative Cost per Outage Event Estimates by Onset Time and Customer Class – Weekends



Interestingly, residential and large business customers exhibit a similar trend, where outage costs vary moderately with lower costs during the morning and afternoon and higher costs during the evening and night throughout the week. Outage costs are higher during the evening and night for residential customers because they are more likely to be home at these times. For large business customers, considering that many operate 24 hours per day, 7 days per week, outages with different onset times likely have a similar impact on production, but the overall outage cost may be greater during the evening and night because outage response may require overtime or emergency staff.

Outage costs for agricultural customers vary more than those of residential and large business customers, but less than SMB outage costs. Agricultural outage costs during the morning and afternoon are higher than the base value on weekdays and weekends, which is not surprising considering that much agricultural work is conducted during daylight hours throughout the week.

1.4 Comparison to Previous Studies

PG&E previously carried out an outage cost study for all 4 customer classes in 2005. In addition, there was a large business study in 1989, an agricultural study in 1991 and residential and SMB in 1993. Table 1-5 compares the cost of a 4-hour, summer afternoon outage for each study year and customer class. The 1989-1993 and 2005 cost per outage event estimates were converted to 2012 dollars using the gross domestic product deflator, which was obtained from the U.S. Department of Commerce's Bureau of Economic Analysis. SMB and agricultural outage costs vary between study years, but these differences are not statistically significant. For residential customers, the difference between 2005 and 2012 is statistically significant and shows a 64.3% increase in reported outage cost since 2005. Although there seems to be a large increase in outage costs for residential customers, some of this difference is due to a change in the residential survey design that improved the accuracy of the estimates. After adjusting for this methodological difference, there is a smaller increase of 18.4% in reported outage cost for residential customers since 2005, which may be due to increased household sizes as a result of economic conditions. Even with these increases in outage costs in the 2012 study, all of the residential cost per event, average kW and unserved kWh estimates are lower than in the other customer classes, as shown above.

Between 1989 and 2005, there was a 53.3% increase in reported outage cost for large business customers, but this difference was not statistically significant. The difference between 2005 and 2012 is statistically significant and shows a 4-fold increase in reported outage cost for large business customers since 2005.[4] While it is possible that outage costs for large business customers have increased significantly since 2005, the results reported here must be used with caution. With the relatively small sample sizes for the large business segment and specific subset of customers with extremely high outage costs, the results for each large business study are subject to large statistical error because they are highly sensitive to the sample that is randomly selected. In the 2012 study, it seems that the random sample included a larger amount of these customers with extremely high outage costs. In addition, the 2012 study had lower large business response rates than those of the 1989 and 2005 studies, which may have led to non-response bias. Although the assessment presented in Appendix D did not find any observable factors (such as industry type) that led to non-response bias, there could have been unobservable factors that biased the results upward in light of the relatively low response rates in the 2012 study. Another possibility may be that these high-cost customers are more prevalent in PG&E's large business population than they were in the past, which may require further research.

Table 1-5:
Cost of a 4-Hour, Summer Afternoon Outage by Study Year and Customer Class

Study Year	Residential (2012$)	SMB (2012$)	Large Business (2012$)	Agricultural (2012$)
1989-1993	$8.37	$4,738.3	$73,948	$1,104.8
2005	$9.31	$3,884.4	$113,336	$1,945.1
2012	$15.30	$6,138.9	$460,263	$1,367.1

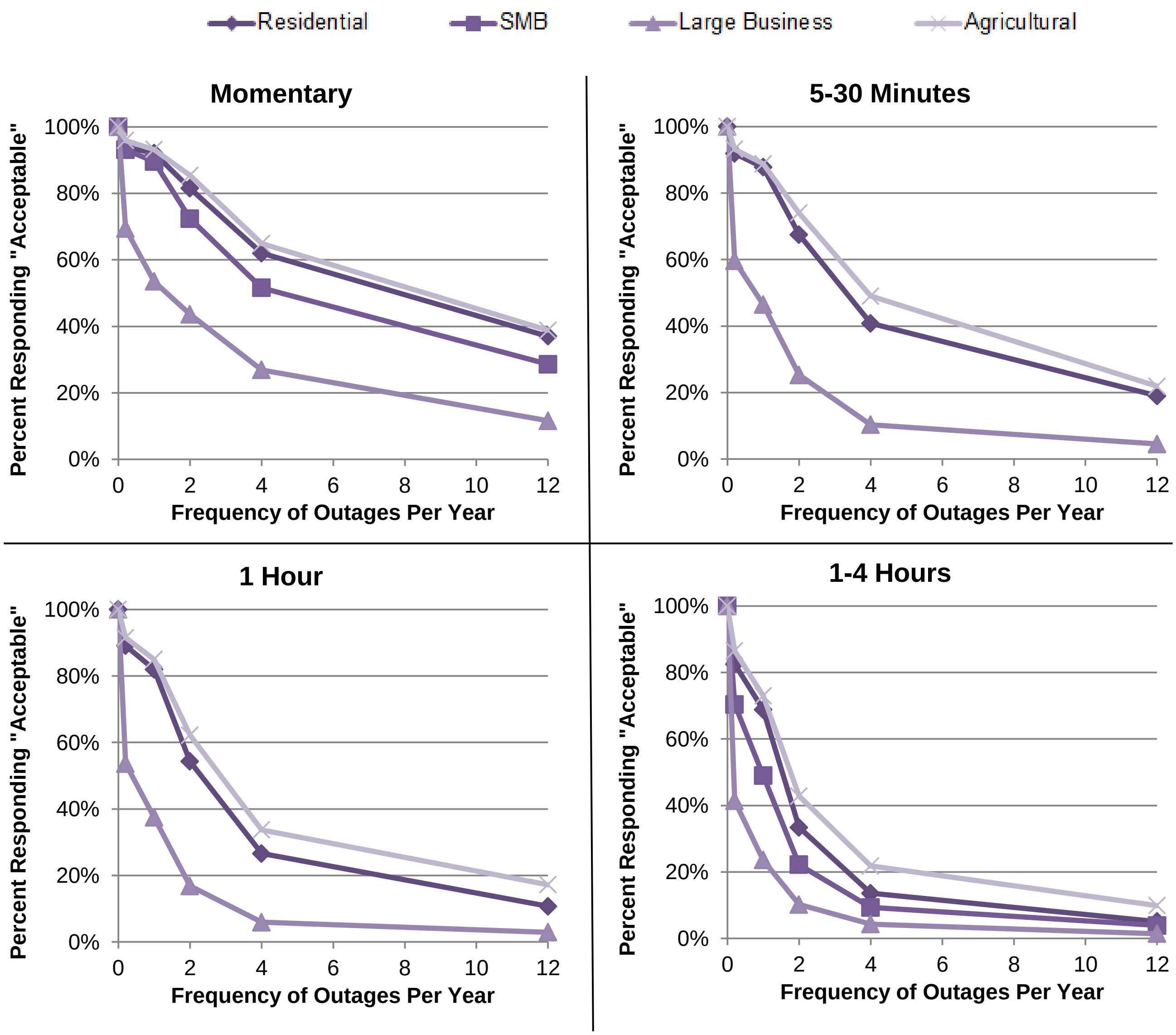
1.5 Acceptable Level of Service Reliability

In the survey, respondents were asked to rate hypothetical levels of service reliability as acceptable or unacceptable. Each level of service reliability referred to a specific outage duration and frequency. Figure 1-4 shows the percent of customers rating each combination of outage frequency and duration as acceptable. As expected, a customer's level of service reliability becomes less acceptable as outage duration increases and the number of outages per year increases. Even though cost per unserved kWh for outages longer than 1 hour is lower for large business customers than it is for SMB customers, large business customers expect a substantially higher level of reliability. One outage of 1

[4] Note that statistical significance in this case implies that there was an increase in reported cost, but does not necessarily confirm that the magnitude of the increase was exactly 4-fold.

to 4 hours per year is acceptable to 23.6% of large business customers, compared to 49% of SMB customers. Agricultural customers expect the lowest level of reliability. One outage of 1 to 4 hours per year is acceptable to 73% of agricultural customers, compared to 68.8% of residential customers. Between regions, there are only slight differences in what level of reliability is considered acceptable for residential, SMB and agricultural customers, which is somewhat unexpected given the regional differences in outage costs. Large business was the only segment for which there is a substantial difference in the acceptable level of service reliability by region. Bay Area large business customers expect a very high level of service reliability.

Figure 1-4:
Percent of Customers Rating Each Combination of
Outage Frequency and Duration as Acceptable by Customer Class



To determine what percent of customers receives service that they consider acceptable, the acceptable level of service reliability questions were compared with the number of outages customers reported experiencing over the past 12 months. Table 1-6 provides the results of this analysis by outage duration and customer class for the survey in 2005 and 2012. In the 2012 study, up to 87% of residential and 81% of SMB customers reported that they receive service that they say is acceptable. Across all outage durations, these results are very similar to 2005 for residential and SMB customers. Large business and agricultural customers were less likely to receive service they say is acceptable, and as in the 2005 study, momentary outages for large business customers are the type of outage that most likely leads to unacceptable service.

Table 1-6:
Percent of Customers Receiving Service Rated as Acceptable by Study Year and Customer Class

Outage Duration	Residential		SMB		Large Business		Agricultural	
	2005	2012	2005	2012	2005	2012	2005	2012
Momentary	89%	91%	88%	87%	70%	68%	88%	86%
5-30 Minutes	95%	94%	-	-	86%	84%	91%	90%
Up to 1 Hour	-	-	83%	85%	-	-	-	-
1 Hour	94%	95%	-	-	92%	81%	92%	87%
1-4 Hours	85%	87%	82%	81%	78%	73%	83%	76%

2 Introduction

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- Estimate 2012 outage costs by customer class and region;
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Since VOS cannot be measured directly, it is estimated from outage cost surveys of utility customers. These cost estimates can be used to assess the cost-effectiveness of investments in generation, transmission and distribution systems and to strategically compare alternative investments in order to determine which provides the most combined benefits to the utility and its customers. This comprehensive approach to valuing reliability, commonly known as "value-based reliability planning," has been a well-established theoretical concept in the utility industry for the past 30 years.[5] With the methodological improvements in this study, the 2012 results can be directly applied to many different types of utility investments at the generation, transmission and distribution level.

2.1 Study Methodology

The objectives above were addressed in this study by conducting 4 separate outage cost surveys (one for each customer class) during late 2011 and early 2012. This survey methodology has been implemented by many electric utilities throughout the United States over the past 25 years. This study and the prior studies employed a common survey methodology, including sample designs, measurement protocols, survey instruments and operating procedures. This methodology is described in detail in EPRI's Outage Cost Estimation Guidebook.[6] The results of 28 prior studies are part of a meta-analysis of nationwide outage costs that is summarized in a 2009 report by Lawrence Berkeley National Laboratory (LBNL).[7]

Although the basic methodology is similar to previous work, the 2012 PG&E VOS study featured several noteworthy methodological improvements. These methodological improvements include:

- **Dynamic survey instrument design:** In the 2012 survey instrument, each respondent was randomly assigned to one of 24 different outage onset times (for 24 hours of the day) and reported costs for a weekend scenario with a randomly assigned outage duration. This design

[5] For an early paper on value-based reliability planning, see: Munasinghe, M. (1981). "Optimal Electricity Supply, Reliability, Pricing and System Planning." Energy Economics, 3: 140-152.

[6] Sullivan, M.J., and D. Keane (1995). *Outage Cost Estimation Guidebook*. Report no. TR-106082. Palo Alto, CA: EPRI.

[7] Sullivan, M.J., M. Mercurio, and J. Schellenberg (2009). *Estimated Value of Service Reliability for Electric Utility Customers in the United States*. Lawrence Berkeley National Laboratory Report No. LBNL-2132E.

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- **Oversampling in Bay Area:** During the sample design process, FSC analyzed how aggregate economic output per unit of electricity use varied across PG&E's service territory. This analysis found that outage costs are likely to be significantly higher in the Bay Area than in other parts of PG&E's service territory. Therefore, the sample design had specific quotas for the number of Bay Area and non-Bay Area customers and included an oversampling of non-residential customers in the Bay Area. With this approach, the results were able to account for differences between Bay Area and non-Bay Area customers.
- **Optimized sample design:** The sample design took advantage of information from the 2005 PG&E VOS study to optimally define the number of usage strata and boundaries for the usage strata. Taking advantage of previous results allowed FSC to determine the sample stratification method that minimized the variance in the estimated outage cost, which maximized the precision of the 2012 estimates.
- **Improved customer damage functions:** Customer damage functions are statistical models that predict how outage costs vary across customers, outage duration and other outage characteristics. In the 2005 study, a Tobit regression model was used to estimate the customer damage functions. However, the 2009 meta-analysis for LBNL showed that a two-part econometric model is more appropriate for modeling outage cost data. In this study, FSC applied the two-part econometric model to this dynamic survey data to develop estimates for how outage costs vary by time of day and week for each customer class.
- **Customized cost per unserved kWh estimates:** To develop the cost per unserved kWh estimates, it is necessary to produce a load ratio that estimates the relative amount of unserved electricity for each outage scenario and respondent. Previous studies would simply apply the load factor (ratio of average kW to peak kW) for each customer class because the outage scenarios were primarily focused on peaking periods. In this study, the cost per unserved kWh estimates were customized to each scenario (based on outage timing) and each respondent (based on rate profile).

2.2 Economic Value of Service Reliability

The purpose of VOS research is to measure the economic value of service reliability, using information regarding outage costs as a proxy. Under the general theory of welfare economics, the economic value of service reliability is equal to the economic losses that customers experience as a result of service interruptions. The history of efforts to measure customer outage costs goes back several decades. In that time, several approaches have been used. These include:

- Scaled macro-economic indicators (i.e., gross domestic product, wages, etc.);
- Market-based indicators (e.g., incremental value of reliability derived from studies of price–elasticity of demand for service offered under non-firm rates); and
- Survey-based indicators (i.e., cost estimates obtained from surveys of representative samples of utility customers).

The most widely used approach to estimating customer outage costs is through analysis of data collected via customer surveys. In a customer outage cost survey, a representative sample of customers is asked to estimate the costs they would experience given a number of hypothetical outage scenarios. In these hypothetical outage scenarios, key characteristics of the outages described in these scenarios are varied systematically in order to measure differential effects of service outage events with various different characteristics. A variety of statistical techniques are then used to identify and describe the relationships between customer economic losses and outage attributes.

Survey-based methods are generally preferred over the other measurement protocols because they can be used to obtain outage costs for a wide variety of reliability conditions not observable using the other techniques. As in 2005, these methods were selected for use in the 2012 PG&E VOS study.

2.3 Valuation Methods

Two basic valuation methods are used to measure outage costs in the surveys – direct cost measurement and willingness-to-pay (WTP). Direct cost measurement techniques involve asking customers to estimate the direct costs they will experience during a service outage. WTP measurement techniques involve measuring the amount customers would be willing to pay to avoid experiencing the outage. In both approaches, the surveys ask respondents to provide these estimates for a number of outage scenarios, which vary in terms of the characteristics of the event.

2.3.1 Direct Cost Measurement

For non-residential customers (SMB, large business and agricultural), direct cost measurement was used in this study because their outage costs are more tangible and much less difficult to estimate directly. At its most general level, the direct cost of an outage is defined as follows:

$$\begin{aligned} Direct\ Cost = Value\ of\ Lost\ Production + Outage\ Related\ Costs \\ - Outage\ Related\ Savings \end{aligned}$$

The *Value of Lost Production* is the amount of revenue the surveyed business would have generated in the absence of the outage minus the amount of revenue it was able to generate given that the outage occurred. It is their net loss in the economic value of production after their ability to make up for lost production has been taken into account. It includes the entire cost of making or selling the product as well as any profit that could have been made on the production.

Outage Related Costs are additional production costs directly incurred because of the outage. These costs include:

- Labor costs to make up any lost production (which can be made up);
- Labor costs to restart the production process;
- Material costs to restart the production process;
- Costs resulting from damage to input feed stocks;
- Costs of re-processing materials (if any); and
- Cost to operate backup generation equipment.

Outage Related Savings are production cost savings resulting from the outage. When production or sales cannot take place, there are economic savings resulting from the fact that inputs to the production or sales process cannot be used. For example, during the time electric power is interrupted, the enterprise cannot consume electricity and thus will experience a savings on their electric bill. In many cases, savings resulting from outages are small and do not significantly affect outage cost calculations. However, for manufacturing enterprises where energy and feedstock costs account for a significant fraction of production cost, these savings may be quite significant and must be measured and subtracted from the other cost components to ensure outage costs are not double counted. These savings include:

- Savings from unpaid wages during the outage (if any);
- Savings from the cost of raw materials not used because of the outage;
- Savings from the cost of fuel not used; and
- Scrap value of any damaged materials.

In measuring outage costs, only the incremental losses resulting from unreliability are included in the calculations. Incremental losses include only those costs described above and beyond the normal costs of production. If the customer is able to make up some percentage of their production loss at a later date (e.g., by running the production facility during times when it would normally be idle), the outage cost does not include the full value of the production loss. Rather, it is calculated as the value of production not made up plus the cost of additional labor and materials required to make up the share of production eventually recovered.

2.3.2 Willingness-to-Pay Approach

Cost estimates for the residential segment are based on a WTP question because residential customers do not experience many directly measureable costs during an outage. Considering that most of the outage cost for residential customers is a result of inconvenience or hassle, WTP is a better representation of their underlying costs. The WTP approach to outage cost estimation is quite different than the direct cost measurement approach. Rather than asking what an outage would cost the customer, the WTP approach asks how much the customer would pay to avoid its occurrence. This technique employs the concept of compensating valuation – customers are asked to estimate the economic value that would leave their welfare unchanged compared to a situation in which no outage occurred. This approach is especially useful when intangible costs are present, which by their nature, are difficult to estimate using the direct cost measurement approach.

2.4 Report Organization

The remainder of this report proceeds as follows:

- **Section 3 – Survey Methodology:** This section covers the survey methodology, including details on the survey implementation approach by customer class, survey instrument design, sample design and data collection procedures for each customer class.
- **Section 4 – Outage Cost Estimation Methodology**: The results of this study focus on the following 3 key metrics – cost per outage event, cost per average kW and cost per unserved kWh. This section on the outage cost estimation methodology explains what each of these 3 key metrics represents, how they are calculated from the survey data and how they are related to each other.
- **Sections 5 through 8 – Results**: These 4 sections provide the results for each customer class, beginning with the 3 key metrics defined in Section 4 for the service territory as a whole and disaggregated by region. Comparisons of outage costs in the two regions are discussed and confidence intervals for the estimates are provided. Then, each section provides results on how outage costs vary by the time of day and week for each customer class. This

discussion is followed by a comparison of the 2012 outage cost estimates to those of previous studies. Finally, each section concludes with results related to the level of reliability that each customer class considers acceptable.

- **Appendix A – Sampling Strategy Determination:** This appendix provides more details on the sample design, specifically focusing on how the final sampling strategy was determined for each customer class.
- **Appendix B – Customer Damage Functions:** This appendix details the customer damage functions, which are econometric models that predict how outage costs vary across customers, outage duration and other outage characteristics. For example, these models were used to develop the results in Sections 5 through 8 related to how outage costs vary by the time of day and week for each customer class.
- **Appendix C – Assessment of Non-response Bias:** In this appendix, a systematic assessment of non-response bias in the survey is provided.
- **Appendix D – 2012 Large Business Outage Cost Estimates by Level of Service Reliability:** Many large business customers are accustomed to a very high level of reliability and rarely experience sustained power interruptions. Therefore, this appendix provides the large business outage cost estimates by level of service reliability. For distribution planning applications, FSC recommends using the outage cost estimates associated with large business customers that have experienced one or more sustained outages in the past year.
- **Appendices E through H – Survey Instruments:** These 4 appendices include the survey instruments for each customer class.

3 Survey Methodology

Table 3-1 provides an overview of the 2012 VOS survey implementation approach by customer class. Residential customers were recruited with a letter that encouraged them to go online to complete the survey (the letter included a link to the online survey along with a unique access code specific to each customer). If a residential customer did not complete the survey online, a paper copy was sent. SMB and agricultural customers were recruited by telephone and were asked if they preferred to fill out the paper survey or go online to complete the survey. If a customer preferred to fill out the paper survey, it was sent to them by mail. If a customer preferred to go online to complete the survey, a link to the online survey and a unique access code specific to each customer were provided in an email. Large business customers were recruited by telephone and received an in-person interview.

Although all survey instruments included variations of willingness-to-pay (WTP) and direct cost questions, the results in Sections 5 through 8 are based on the valuation method listed in Table 3-1. Cost estimates for the residential segment are based on a WTP question because residential customers do not experience many directly measureable costs during an outage. Considering that most of the outage cost for residential customers is a result of inconvenience or hassle, WTP is a better representation of their underlying costs. For SMB, large business customers and agricultural customers, direct cost measurement is the preferred valuation method because their outage costs are more tangible and much less difficult to estimate directly.

Table 3-1:
2012 VOS Survey Implementation Approach by Customer Class

Customer Class	Sample Design Target	Recruitment Method	Data Collection Approach	Valuation Method	Incentive Provided
Residential	1,000	Letter	Mail/Internet Survey	WTP	Two $2 bills
SMB	1,000	Telephone	Mail/Internet Survey	Direct Cost	$50
Large Business	190	Telephone	In-person Interview	Direct Cost	$50
Agricultural	500	Telephone	Mail/Internet Survey	Direct Cost	$150

3.1 Survey Instrument Design

This discussion of the survey instrument design focuses on the outage scenarios, which were designed the same for all segments. The survey instruments are included as appendices in case more detail is required on other aspects of the survey.

Considering that most customers rarely experience sustained power interruptions, an outage cost survey presents the respondent with hypothetical outage scenarios that are specific to a certain time period. As stated in Section 2, one of the objectives of the study was to compare the 2012 outage cost estimates with those of previous studies. As such, the first outage scenario for each customer class was the same as in the 2005 study. This outage scenario was the 4-hour, summer weekday scenario with a 3 PM onset time and no advance warning. Each results section contains a comparison to previous studies that was based on the responses to this outage scenario.

Another key objective of this study was to estimate the average outage cost across all time periods. In the 2005 study, outage scenarios were primarily limited to summer weekday afternoons. Outage cost estimates for this time period are useful for generation planning, but not transmission and distribution planning for which the power interruptions of interest occur at all times. In fact, outages are distributed throughout the day for all customer classes. As shown in Figure 3-1, there is no single hour for any customer class that accounts for more than 6.5% of outages or less than 2% of outages. Instead of having a study that produces results specifically for one time period, the outage scenarios in the 2012 VOS study were designed to capture information across all time periods. This objective was accomplished by randomizing the outage scenarios in proportion to the distribution of onset times in Figure 3-1. As a result, the outage cost estimates provided in Sections 4 through 8 are representative of the average outage cost across all time periods as opposed to just one time period.

Figure 3-1:
Distribution of Outages by Onset Time and Customer Class (2008-2010)

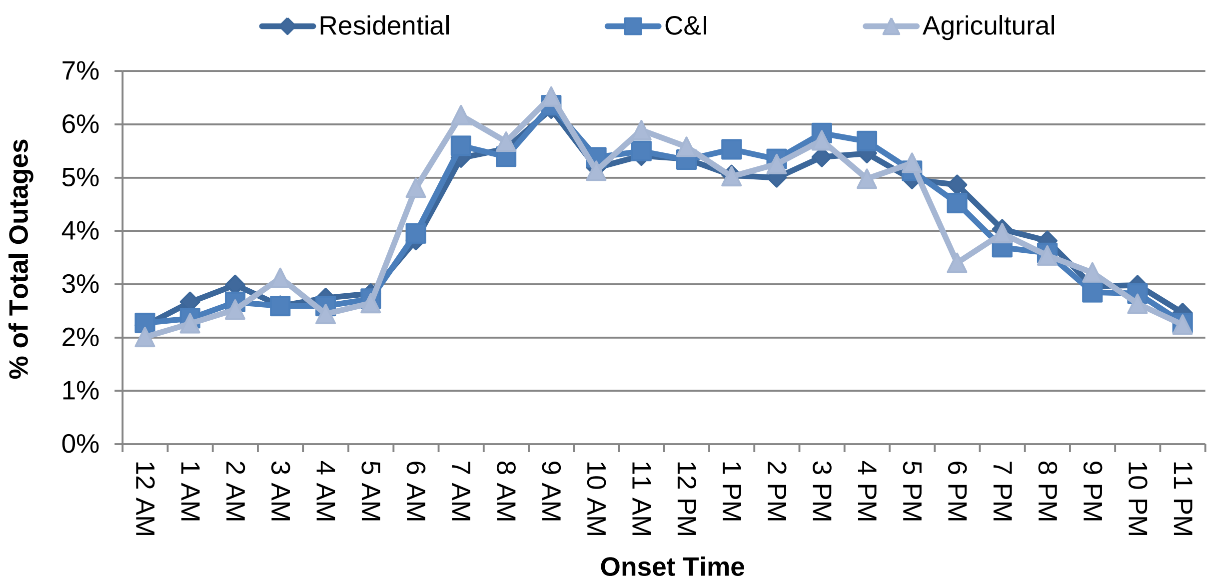


Table 3-2 provides an example set of outage scenarios. As discussed above, scenario A was the same for all respondents so that this study could be compared with the 2005 study. In accordance with Figure 3-1, this onset time of 11 AM for scenarios B through F was assigned to approximately 5.5% of respondents. Each respondent was assigned the same onset time for scenarios B through F in order to minimize respondent burden. An alternative was to randomize the onset time for every scenario and respondent, but that would likely lead to confusion and the survey would be more difficult to complete. To be consistent with scenario A, scenarios B through F were described to occur during the summer and did not include advance warning. Outage costs for the average customer do not vary substantially throughout the year, especially in California,[8] so the season was kept consistent with scenario A even though these estimates can be applied throughout the year. Advance warning was

[8] This conclusion was reached by using estimates from the Department of Energy's Interruption Cost Estimate Calculator, which can be found at ICECalculator.com. Note that this calculator does not report agricultural outage costs separately, so costs may vary throughout the year specifically for agricultural customers. For the average customer overall, the seasonal variation was not substantial.

not included for any of the scenarios because it is rarely provided for distribution or transmission related power interruptions. Scenario F was always the single weekend scenario, which provided very useful information on how outage costs are affected by timing during the week. Finally, each set of scenarios always included durations of 5 minutes, 1 hour, 4 hours, 8 hours and 24 hours. In this example set of outage scenarios, the 1-hour duration was randomly assigned to the weekend outage scenario F, which was not always the case. In fact, there were 120 different, randomly assigned versions of the survey (5 possible durations for the weekend scenario X 24 possible hours for the onset times).

Table 3-2:
Example Set of Outage Scenarios

Scenario	Season	Time of Week	Onset Time	Warning	Duration
A	Summer	Weekday	3:00 PM	No	4 hours
B	Summer	Weekday	11:00 AM	No	4 hours
C	Summer	Weekday	11:00 AM	No	5 minutes
D	Summer	Weekday	11:00 AM	No	8 hours
E	Summer	Weekday	11:00 AM	No	24 hours
F	Summer	Weekend	11:00 AM	No	1 hour

3.2 Sample Design

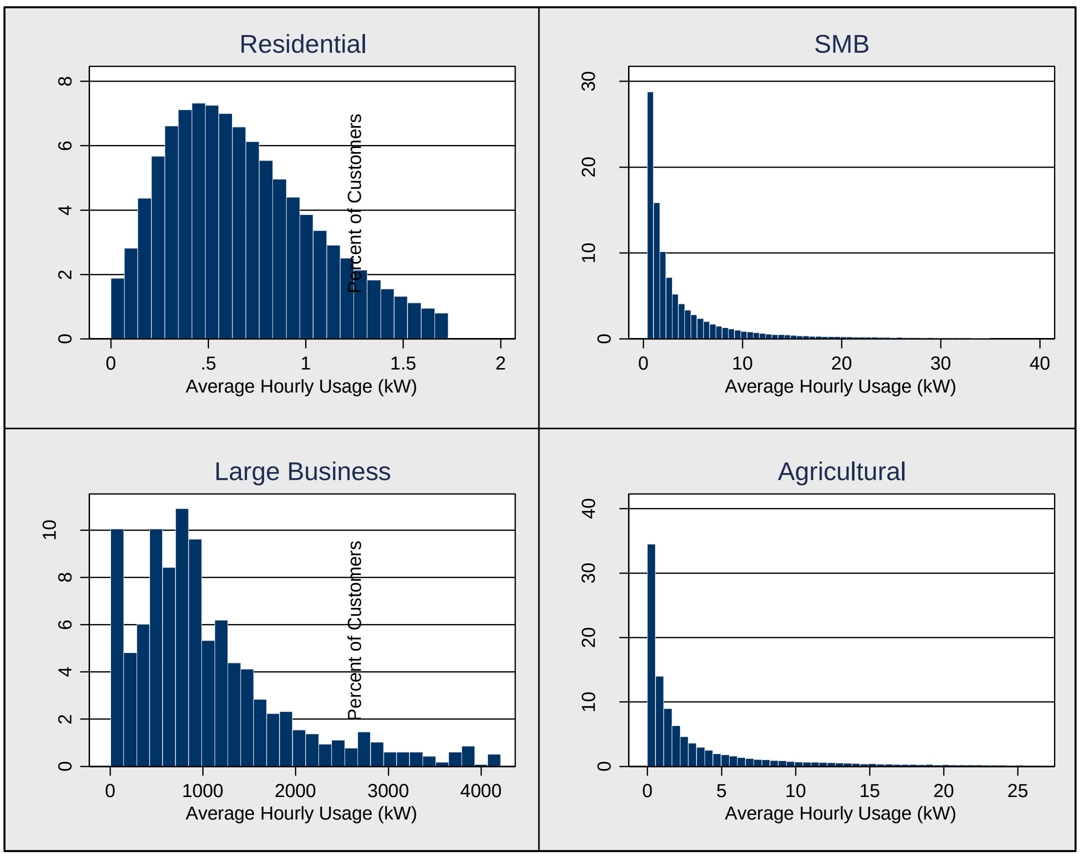
The study aimed for the following amount of completed surveys for each customer class:

- 1,000 residential customers;
- 1,000 SMB customers;
- 190 large business customers; and
- 500 agricultural customers.

Before detailing the sample design methodology and how these sample points were distributed among usage categories and region, it is important to note that a "customer" refers to a premise in the three non-residential segments, not an individual account. When SMB, large business and agricultural customers complete an outage cost survey, they provide answers for the premise associated with all of their accounts at a certain address. Many of these premises only have one account at that address, in which case the premise-level estimates and account-level estimates are identical. However, there are some non-residential premises that have multiple accounts for the same business, in which case the respondent is rarely able to provide the cost estimates for an individual account within that premise. Therefore, usage and customer contact information were aggregated across all of the accounts associated with each business at each premise, and then the customers were sampled. For the residential segment, a "customer" refers to an individual account because it is rare that a residential customer has multiple accounts at a single address.

The sample design methodology was determined using the approach described in Appendix A. This approach to determining the sample design was a substantial improvement on previous studies because it took advantage of information from the 2005 PG&E VOS study to optimally define the number of usage strata and boundaries for the usage strata. This sampling approach is necessary because the distribution of usage per customer is highly skewed. As shown in Figure 3-2, the vast majority of customers is clustered towards the lower end of the usage distribution for each customer class and there is a "long tail" of high usage customers towards the upper end of the distribution. Considering that usage is a proxy for outage costs, an objective of the sample design methodology was to ensure that a sufficient amount of high usage customers was included in the sample. A simple random sample would not accomplish this objective because high usage customers would have a very low probability of being selected for the sample considering that they account for a small percentage of each segment.

Figure 3-2:
Distribution of Average Hourly Usage by Customer Class
(Top 5th Percentile for Each Customer Class Omitted)



3.2.1 Regional Considerations

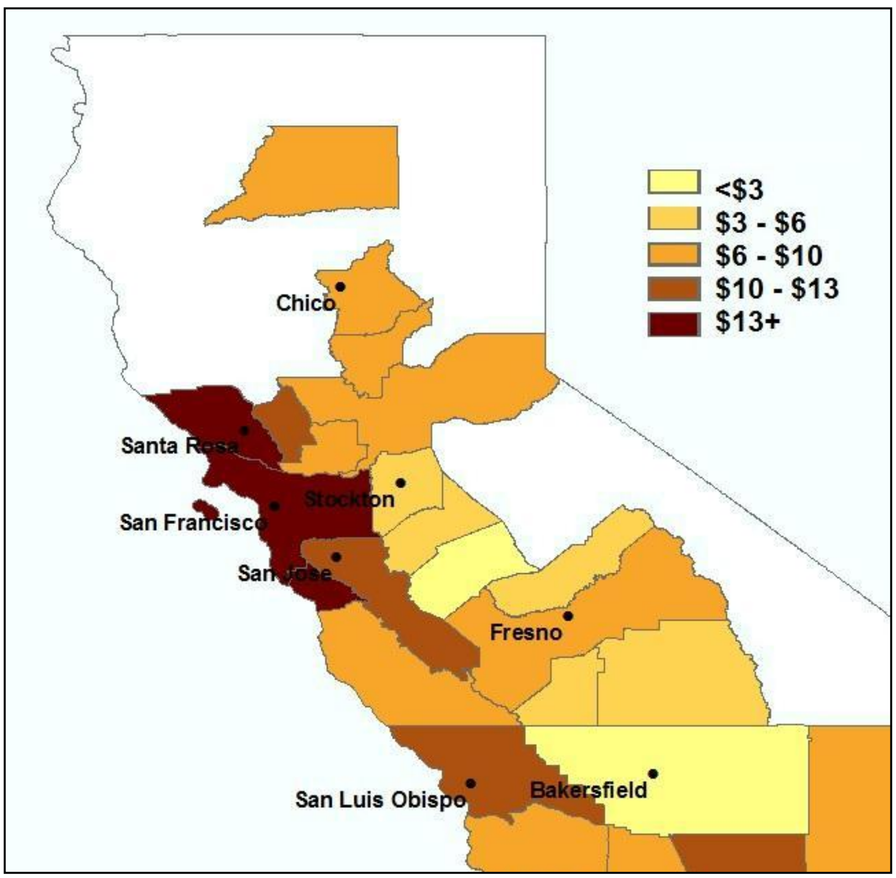
In addition to estimating outage costs at the system level, there is value in determining outage costs for non-residential customers within certain areas of PG&E's service territory with high outage costs. In order to identify areas with high outage costs, FSC analyzed gross domestic product (GDP) per non-residential kWh for each metropolitan statistical area (MSA)[9] in PG&E's service territory. Although

[9] MSAs are the smallest geographic unit for which the U.S. Department of Commerce provides GDP information. In PG&E's service territory, each MSA is made up of a contiguous grouping of one to five counties. Some of PG&E's service territory is not assigned to an MSA because areas with relatively low population density are not assigned to an MSA.

GDP per kWh tends to substantially underestimate outage costs, it serves as a good proxy for the geographic variation of non-residential outage costs normalized by usage. Residential customers were not included in this analysis because a good proxy for geographic variation has not been identified and their outage costs are substantially lower and less variable.

Figure 3-3 provides a map of GDP per non-residential kWh for each MSA in PG&E's service territory. GDP per non-residential kWh varies greatly from $2.4 in the Bakersfield-Delano MSA to $15.3 in the San Francisco-Oakland-Fremont MSA. In general, there are extreme differences between the Bay Area and the remaining MSAs in PG&E's service territory. Among the MSAs comprising the 9 Bay Area counties,[10] GDP per non-residential kWh is $13.9 and no lower than $11.1. Outside the Bay Area, GDP per non-residential kWh does not exceed $10.9 and is $4.7 overall, *one-third* that of the Bay Area. Therefore, the sample design had specific quotas for the number of Bay Area and non-Bay Area customers in each usage category and included an oversampling of 200 SMB, 40 large business and 100 agricultural customers in the Bay Area.[11] With this approach, the results were able to account for differences between Bay Area and non-Bay Area customers.

Figure 3-3:
GDP per Non-Residential kWh for Each
Metropolitan Statistical Area in PG&E's Service Territory



10 San Francisco, San Mateo, Santa Clara, Alameda, Contra Costa, Marin, Santa Cruz, Sonoma and Napa

11 For the purposes of this study, the Bay Area region included the following 8 PG&E divisions: San Francisco, Peninsula, De Anza, San Jose, Mission, East Bay, Diablo and North Bay. The non-Bay Area region included all other divisions.

3.2.2 Residential Customers

Table 3-3 summarizes the sample design for residential customers, which had 4 usage categories. The population of residential customers is divided roughly evenly by region. The non-Bay Area region accounted for a larger portion of the sample because this region has a relatively higher percentage of customers in the larger usage categories for which the Neyman allocation required a relatively large sample size. In addition, the sample design for the residential segment did not include oversampling for customers in the Bay Area. The smallest usage category (0 to 1.7 average kW) had the highest sample design target, and the rest of the sample was distributed roughly evenly between the remaining 3 usage categories. As expected by the sample design methodology, the largest customers accounted for a high proportion of the sample design target relative to their percentage of the population. Across regions, the largest usage category (4.8 to 10 average kW) comprised 0.2% of the population, but 9.3% of the sample. This sample design ensured that the study included a sufficient amount of high usage customers that were likely to have higher and more variable outage costs.

Table 3-3:
Sample Design Summary – Residential

Region	Usage Category (Average kW)	Population	% of Population	Sample Design Target	% of Sample
Bay Area	0 to 1.7	2,054,448	49.0%	374	37.4%
	1.7 to 2.7	52,636	1.3%	28	2.8%
	2.7 to 4.8	10,732	0.3%	27	2.7%
	4.8 to 10	2,263	0.1%	25	2.5%
	Bay Area Overall	*2,120,079*	*50.5%*	*454*	*45.4%*
Non-Bay Area	0 to 1.7	1,907,383	45.5%	343	34.3%
	1.7 to 2.7	135,229	3.2%	73	7.3%
	2.7 to 4.8	27,460	0.7%	62	6.2%
	4.8 to 10	5,948	0.1%	68	6.8%
	Non-Bay Area Overall	*2,076,020*	*49.5%*	*546*	*54.6%*
Overall		**4,196,099**	**100%**	**1,000**	**100%**

3.2.3 Small & Medium Business Customers

Table 3-4 summarizes the sample design for SMB customers, which had 5 usage categories. Although the non-Bay Area region accounted for a larger percentage of the population, 58.8% of the sample was allocated to the Bay Area because the sample design included an oversampling of 200 SMB customers in the Bay Area. As expected by the sample design methodology, the largest customers accounted for a high proportion of the sample design target relative to their percentage of the population. Across regions, the largest usage category (222 to 884 average kW) comprised 2.4% of the population, but 18.5% of the sample. This sample design ensured that the study included a sufficient amount of high usage customers that were likely to have higher and more variable outage costs.

Table 3-4:
Sample Design Summary – SMB

Region	Usage Category (Average kW)	Population	% of Population	Sample Design Target	% of Sample
Bay Area	0 to 4	72,700	20.1%	140	14.0%
	4 to 13	44,431	12.3%	93	9.3%
	13 to 46	30,790	8.5%	113	11.3%
	46 to 222	14,034	3.9%	120	12.0%
	222 to 884	4,904	1.4%	122	12.2%
	Bay Area Overall	*166,859*	*46.2%*	*588*	*58.8%*
Non-Bay Area	0 to 4	95,231	26.4%	122	12.2%
	4 to 13	49,670	13.8%	68	6.8%
	13 to 46	31,331	8.7%	78	7.8%
	46 to 222	14,010	3.9%	81	8.1%
	222 to 884	3,749	1.0%	63	6.3%
	Non-Bay Area Overall	*193,991*	*53.8%*	*412*	*41.2%*
Overall		**360,850**	**100%**	**1,000**	**100%**

3.2.4 Large Business Customers

Table 3-5 summarizes the sample design for large business customers, which had 4 usage categories. Although the population of large business customers is divided roughly evenly by region, 61.6% of the sample was allocated to the Bay Area because the sample design included an oversampling of 40 large business customers in the Bay Area. As expected by the sample design methodology, the largest customers accounted for a high proportion of the sample design target relative to their percentage of the population. Across regions, the largest usage category (2,981 to 65,791 average kW) comprised 9% of the population, but 36.9% of the sample. This sample design ensured that the study included a sufficient amount of high usage customers that were likely to have higher and more variable outage costs.

Table 3-5:
Sample Design Summary – Large Business

Region	Usage Category (Average kW)	Population	% of Population	Sample Design Target	% of Sample
Bay Area	0 to 600	145	11.8%	25	13.2%
	600 to 1,268	295	24.1%	26	13.7%
	1,268 to 2,981	134	10.9%	21	11.1%
	2,981 to 65,791	56	4.6%	45	23.7%
	Bay Area Overall	*630*	*51.4%*	*117*	*61.6%*

Region	Usage Category (Average kW)	Population	% of Population	Sample Design Target	% of Sample
Non-Bay Area	0 to 600	241	19.7%	28	14.7%
	600 to 1,268	157	12.8%	6	3.2%
	1,268 to 2,981	143	11.7%	14	7.4%
	2,981 to 65,791	54	4.4%	25	13.2%
	Non-Bay Area Overall	*595*	*48.6%*	*73*	*38.4%*
Overall		**1,225**	**100%**	**190**	**100%**

3.2.5 Agricultural Customers

Table 3-6 summarizes the sample design for agricultural customers, which had 3 usage categories. The non-Bay Area region accounted for the vast majority of agricultural customers in the population. Nonetheless, 23% of the sample was allocated to the Bay Area because the sample design included an oversampling of 100 agricultural customers in the Bay Area. Without this oversampling, it would not have been possible to reliably estimate agricultural outage costs separately for the Bay Area. In addition, considering that outage costs were higher and more variable in the Bay Area, this oversampling improved the precision of the estimates for the agricultural segment as a whole.

Table 3-6:
Sample Design Summary – Agricultural

Region	Usage Category (Average kW)	Population	% of Population	Sample Design Target	% of Sample
Bay Area	0 to 0.5	1,469	1.9%	39	7.8%
	0.5 to 6.2	1,714	2.2%	43	8.6%
	6.2 to 5,511	280	0.4%	33	6.6%
	Bay Area Overall	*3,463*	*4.5%*	*115*	*23.0%*
Non-Bay Area	0 to 0.5	22,939	29.9%	123	24.6%
	0.5 to 6.2	34,427	44.9%	143	28.6%
	6.2 to 5,511	15,916	20.7%	119	23.8%
	Non-Bay Area Overall	*73,282*	*95.5%*	*385*	*77.0%*
Overall		**76,745**	**100%**	**500**	**100%**

3.3 Data Collection Procedures

This section summarizes the data collection procedures for each customer class.

3.3.1 Residential Customers

The residential survey was carried out by mail (with the ability to respond online if a respondent desired to do so). It was distributed to the target respondents in two waves. In the first wave, respondents received a cover letter on PG&E stationery explaining the purpose of the study and requesting their participation. An incentive of two $2 bills was mailed with the initial letter to all target respondents. This letter also contained a URL and respondent ID number so that respondents could complete the survey online. Two weeks after the first wave was mailed, respondents who did not complete the online survey received a reminder letter with a paper copy of the survey. The letters and survey packet included an 800 number that respondents could call to verify the legitimacy of the survey and ask any questions they had.

3.3.2 Small & Medium Business Customers

SMB customers were first recruited by telephone to ensure that FSC identified the appropriate individuals for answering questions related to energy and outage issues for that company; and to secure a verbal agreement from them to complete the survey. Telephone interviewers explained the purpose of the survey and indicated that an incentive was to be provided to thank the respondent for their time. The individuals were then sent an email containing an individualized survey link or had the survey package mailed or faxed to them containing:

- Additional explanation of the purpose of the research;
- Clear and easy-to-understand instructions for completing the survey questions;
- A telephone number they could call if they had questions about the research or wished to verify its authenticity;
- The survey booklet (or a link in the email to compete the survey online); and
- Return envelope with pre-paid postage (for the paper survey option).

One week after the survey link was emailed or the survey was faxed, respondents were given a reminder call. Customers who requested regular mail received their reminder calls in about 2 weeks. About 10 days after the reminder calls were made to the email recipients, the email was re-sent to anyone who hadn't completed it. If the survey was still not completed within 10 days, it was assumed that the customer would not complete the survey and they were not contacted again. An incentive of $50 was mailed to respondents who completed the survey form.

3.3.3 Large Business Customers

For large business customers, an experienced telephone recruiter first located and recruited an appropriate representative at each of the sampled premises. The target respondent was usually a plant manager or plant engineering manager – someone who was highly familiar with the cost structure of the enterprise. The recruiter first identified the target respondent by calling the phone number of the company representative in PG&E's customer database. Once the target respondent was identified and agreed to participate, a scheduler called back within the following two days to set up an appointment with the field interviewer. Once the appointment was scheduled, FSC emailed them a confirmation along with a written description of the study and an explanation of the information they were being asked to provide. The interview was scheduled at the convenience of the customer. A financial incentive of $150 was offered for completion of the information. On the agreed upon date, FSC's field interviewer visited the sampled site and conducted the in-person interview.

3.3.4 Agricultural Customers

The data collection procedures for agricultural customers were the same as in the SMB segment.

4 Outage Cost Estimation Methodology

The results sections for each customer class (Sections 5 through 8) primarily focus on the following three outage cost metrics:

- Cost per Outage Event;
- Cost per Average kW; and
- Cost per Unserved kWh.

Before presenting the results, it is important to understand how each of these metrics was derived. This section begins with a description of the cost per outage event estimate because it came directly from the survey responses and the other cost metrics were derived from this one.

Cost per outage event is the average cost per customer resulting from each outage duration. It was derived by simply calculating a weighted average of the values that the respondent provided on the survey. Each scenario on the survey focused on a specific outage event and then asked the respondent to provide the cost estimate. The respondent was basically providing the cost per outage event estimate. Before calculating the weighted average of these estimates, the top 0.5% of values normalized by usage was dropped from the analysis. These outliers were dropped because respondents may erroneously provide unrealistically high estimates when taking an outage cost survey, as a result of human error or misunderstanding of the question. After dropping outliers, cost per outage event was derived as an average of the customer responses, weighted by region and usage category for each segment.

Cost per average kW is the average cost per outage event normalized by average customer demand. This metric is useful for comparing outage costs across segments because it is normalized by customer demand. Cost per average kW was derived by dividing average cost per outage event by the weighted average customer demand among respondents for each outage duration by customer class. It is a ratio of the average values as opposed to the average of the ratios for each customer. Therefore, for each outage duration and customer class, average cost per event was first calculated using the steps above and then divided by the average demand among respondents. The average demand for each respondent was calculated as the annual kWh usage divided by 8,760 hours in the year, as shown in the following equation:

$$Average\ Demand = \left(\frac{Annual\ kWh\ usage}{8{,}760}\right)$$

As in the cost per outage event average calculation, the average customer demand (the denominator of the ratio) was weighted by region and usage category for each segment.

Cost per unserved kWh is the cost per outage event normalized by the expected amount of unserved kWh for each outage scenario. This metric is useful because it can be readily used in planning applications, for which the amount of unserved kWh as a result of a given outage is commonly available. As in the cost per average kW calculation, cost per unserved kWh is a ratio of the average values as opposed to the average of the ratios for each customer. Therefore, for each duration and customer class, average cost per event was first calculated using the steps above and then divided by the expected unserved kWh. The expected unserved kWh is the estimated quantity of electricity that would have been consumed if an outage had not occurred. Because the outage scenarios in this study occur during various times of the day and week, the average customer demand from the denominator of the cost per average kW calculation could not simply be multiplied by the number of unserved hours in order to develop the expected unserved kWh estimate. Average customer demand had to be adjusted by a load ratio specific to the time of day and week for each outage scenario and then multiplied by the number of unserved hours, as shown in the following equation:

$$Expected\ Unserved\ kWh = Average\ Demand\ \times\ Load\ Ratio\ \times\ Unserved\ Hours$$

The load ratios in this study are the ratio of expected kW (during a specific time interval for a given customer) to average kW. These ratios were assigned to each respondent based on their rate profile and the outage scenario. FSC used 3 years of aggregate hourly load profile data for each PG&E rate profile to develop the average load ratio of each weekday hour and weekend hour for a given customer. These hourly load ratios for each customer were used to calculate the load ratio appropriate to the timing and duration of each outage scenario. For example, a 4-hour outage starting at 3 PM on a weekday would use the average load ratio of weekday hours from 3 PM to 7 PM. A respondent's average demand was then multiplied by the load ratio to estimate the expected demand throughout the course of each outage scenario. This expected demand was then multiplied by the number of unserved hours associated with each outage scenario to estimate the expected amount of unserved kWh for each outage scenario. Finally, cost per outage event was divided by the expected unserved kWh to develop the cost per unserved kWh estimate.

Figure 4-1 shows the average hourly load ratios by customer class for weekday outage scenarios and Figure 4-2 for weekend outage scenarios. These figures provide an understanding of how the average kW values were adjusted to develop the expected unserved kWh specific to each outage scenario. Residential customers generally have below average demand on weekdays until 3 PM and then peak at around 1.4 times average kW from 7 PM to 9 PM. On weekends, residential load is well above average demand starting at around 9 AM and the peak timing and magnitude is similar to weekdays. SMB customer load peaks at over 1.4 times average kW between 10 AM to 4 PM on weekdays. On weekends, SMB customers are below average demand throughout the day. Large business and agricultural customers have much flatter load profiles, staying between 0.8 and 1.2 times average kW throughout the day and week. Although there are multiple rate profiles within each customer class that are not shown in the figures, these average hourly load ratios by customer class provide a general idea of how average kW was adjusted for the expected unserved kWh estimates.

Figure 4-1:
Average Hourly Load Ratios (Hourly kW/Average kW)
by Customer Class for Weekday Outage Scenarios

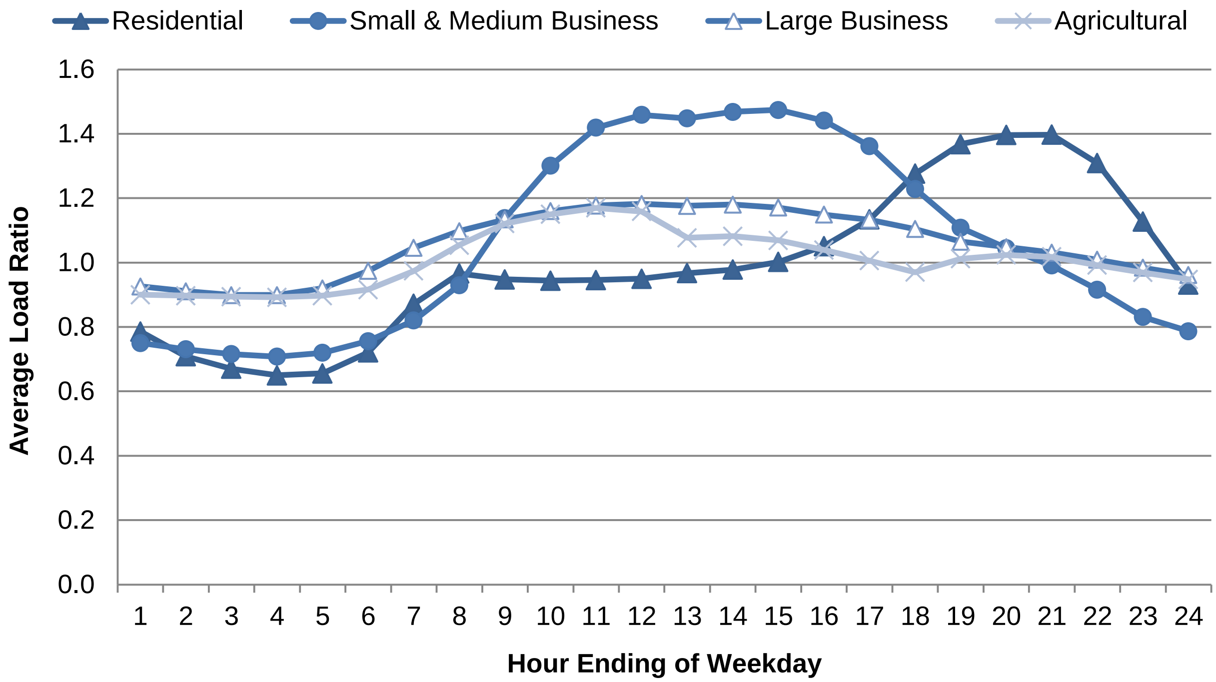
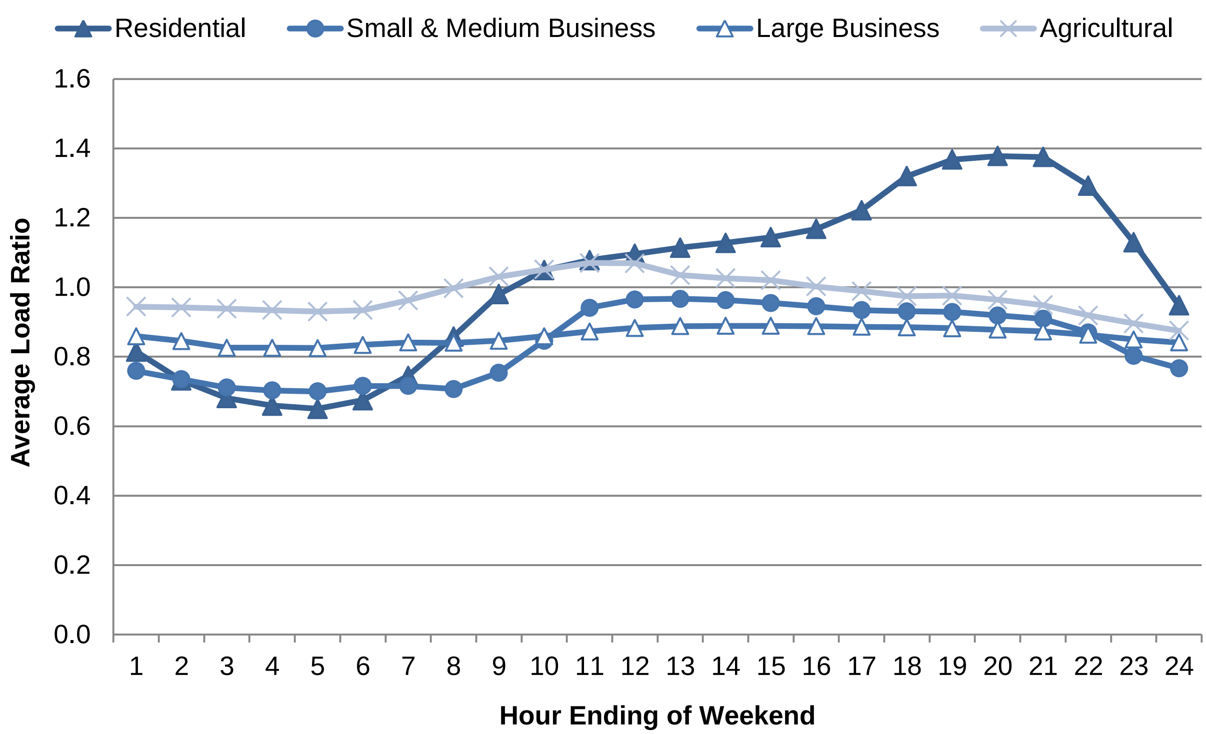


Figure 4-2:
Average Hourly Load Ratios (Hourly kW/Average kW)
by Customer Class for Weekend Outage Scenarios



5 Residential Results

This section summarizes the results for residential customers.

5.1 Response to Survey

Table 5-1 summarizes the survey response for residential customers. With 1,067 total completed surveys, customer response was above the overall sample design target of 1,000. Overall, the survey had a 28.7% response rate that was nearly equal across regions. Among the first 3 usage categories, the response rate was relatively constant by region, varying moderately from 24.0% to 32.7%. High usage residential customers in the 4.8 to 10 average kW category were less likely to respond to the survey and had a response rate below 20% within each region. However, non-response bias among high usage residential customers is not a significant concern for the outage cost estimates because usage category is factored into the stratification weights in the analysis. Appendix C provides a more detailed assessment of the potential sources of non-response bias among residential customers.

Table 5-1:
Customer Survey Response Summary – Residential

Region	Usage Category (Average kW)	Population	Sample Design Target	Records Sampled	Responses	Response Rate
Bay Area	0 to 1.7	2,054,448	374	1,275	392	30.7%
	1.7 to 2.7	52,636	28	104	28	26.9%
	2.7 to 4.8	10,732	27	130	34	26.2%
	4.8 to 10	2,263	25	188	37	19.7%
	Bay Area Overall	*2,120,079*	*454*	*1,697*	*491*	*28.9%*
Non-Bay Area	0 to 1.7	1,907,383	343	1,142	362	31.7%
	1.7 to 2.7	135,229	73	248	81	32.7%
	2.7 to 4.8	27,460	62	267	64	24.0%
	4.8 to 10	5,948	68	362	69	19.1%
	Non-Bay Area Overall	*2,076,020*	*546*	*2,019*	*576*	*28.5%*
Overall		**4,196,099**	**1,000**	**3,716**	**1,067**	**28.7%**

Before presenting the outage cost estimates, it is important to summarize the prevalence of invalid responses. This summary is only provided for the residential segment because its cost estimates are derived from a WTP question. Some respondents are confused by WTP questions or end up answering a question that is quite different from the one that is being asked. For example, customers sometimes react to questions about WTP by redefining the question so that it relates to their ability to pay, their satisfaction with service or whether they think they are being fairly charged for the service they are receiving. Such responses do not accurately reflect the cost of an outage for a customer, so they were removed from the analysis.

To identify these responses, the survey included a follow-up question for respondents that indicated a WTP value of $0. If the respondent verified that WTP was $0 because the outage scenario would not in fact result in any noticeable costs, the $0 response was confirmed as valid and included in the cost estimate calculations. However, if the respondent indicated that there was some other reason that WTP was $0, the response was deemed invalid and not included in the cost estimate calculations. Table 5-2 summarizes the prevalence of invalid responses by outage duration in the residential survey. The percentage of responses deemed invalid varied from 15.7% for an 8-hour outage to 26.0% for a 5-minute outage. This explains why the results below are based on a number of observations that is less than what would be expected from a study with 1,067 responses.

Table 5-2:
Summary of Invalid Responses – Residential

Outage Duration	Total Responses	Invalid Responses		Valid Responses
		N	%	
5 minutes	1,057	275	26.0%	782
1 hour	1,053	223	21.2%	830
4 hours	1,051	187	17.8%	864
8 hours	1,051	165	15.7%	886
24 hours	1,045	166	15.9%	879

5.2 2012 Outage Cost Estimates

Figure 5-1 and Table 5-3 provide the residential cost per outage event estimates. For a 1-hour outage, residential customers experience a cost of $11.89. Residential cost per outage event increases to $22.89 at 8 hours and $31.67 for a 24-hour outage. Bay Area residential customers report higher costs than non-Bay Area customers for all outage durations. At 5 minutes, Bay Area residential cost per outage event is 17.5% higher. The percentage difference between regions increases with duration and at 24 hours, Bay Area residential cost per outage event is 45.3% higher. This result suggests that outages have a relatively higher incremental impact in the Bay Area as duration increases.

Figure 5-1:
2012 Cost per Outage Event Estimates by Region – Residential

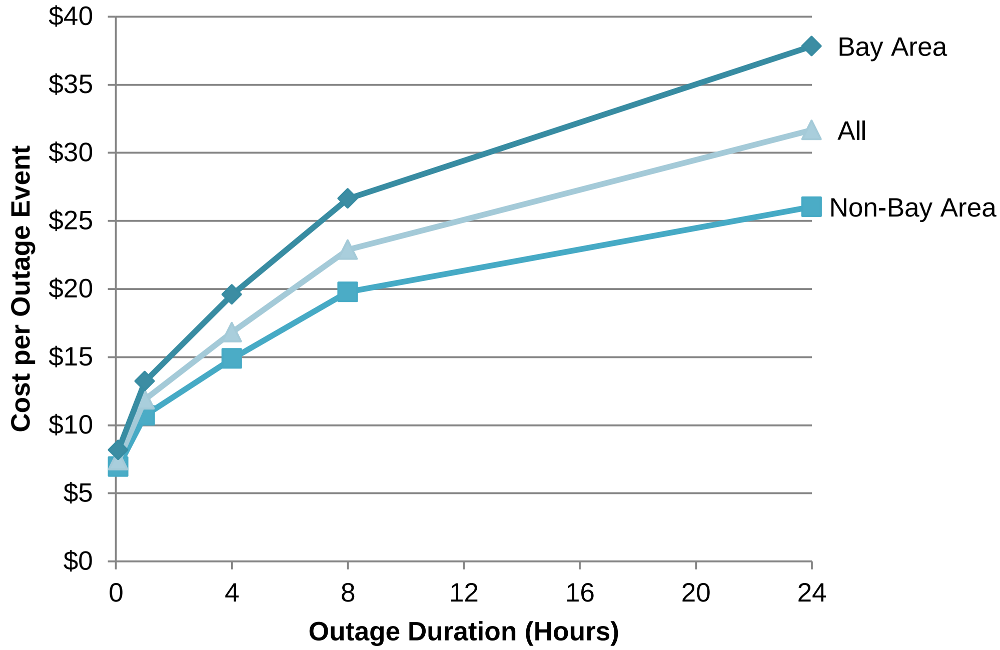


Table 5-3:
2012 Cost per Outage Event Estimates by Region – Residential

Region	Outage Duration	N	Cost per Outage Event	95% Confidence Interval	
				Lower Bound	Upper Bound
Bay Area	5 minutes	362	$8.18	$5.19	$11.16
	1 hour	379	$13.22	$9.18	$17.26
	4 hours	403	$19.59	$15.27	$23.90
	8 hours	407	$26.63	$21.43	$31.83
	24 hours	406	$37.83	$31.73	$43.94
Non-Bay Area	5 minutes	417	$6.96	$4.88	$9.04
	1 hour	447	$10.71	$7.78	$13.64
	4 hours	457	$14.89	$11.59	$18.19
	8 hours	475	$19.79	$16.04	$23.55
	24 hours	469	$26.03	$21.93	$30.12
All	5 minutes	779	$7.41	$5.65	$9.18
	1 hour	826	$11.89	$9.44	$14.33
	4 hours	860	$16.82	$14.19	$19.46
	8 hours	882	$22.89	$19.69	$26.10
	24 hours	875	$31.67	$27.92	$35.42

Table 5-4 summarizes residential cost per average kW. For a 1-hour outage, residential customers experience a cost of $14.86 per average kW. The cost per average kW estimates are roughly 25% higher than the cost per outage event estimates because average demand for residential respondents was around 0.8 kW. Considering that Bay Area residential respondents had relatively low average demand, the difference with non-Bay Area customers is even greater when normalized by average kW. At 5 minutes, Bay Area residential cost per average kW is 41.4% higher. The percentage difference between regions increases with duration and at 24 hours, Bay Area residential cost per outage event is 82.7% higher.

Table 5-4:
2012 Cost per Average kW Estimates by Region – Residential

Region	Outage Duration	N	Cost per Average kW	95% Confidence Interval	
				Lower Bound	Upper Bound
Bay Area	5 minutes	362	$11.86	$7.52	$16.17
	1 hour	379	$18.62	$12.93	$24.31
	4 hours	403	$27.59	$21.51	$33.66
	8 hours	407	$37.51	$30.18	$44.83
	24 hours	406	$54.04	$45.33	$62.77
Non-Bay Area	5 minutes	417	$8.39	$5.88	$10.89
	1 hour	447	$12.17	$8.84	$15.50
	4 hours	457	$16.54	$12.88	$20.21
	8 hours	475	$21.99	$17.82	$26.17
	24 hours	469	$29.58	$24.92	$34.23
All	5 minutes	779	$9.75	$7.43	$12.08
	1 hour	826	$14.86	$11.80	$17.91
	4 hours	860	$21.03	$17.74	$24.33
	8 hours	882	$28.61	$24.61	$32.63
	24 hours	875	$40.09	$35.34	$44.84

Table 5-5 provides the residential cost per unserved kWh estimates. For a 1-hour outage, residential customers experience a cost of $14.86 per unserved kWh, which is equivalent to the cost per average kW estimate because the expected amount of unserved kWh is also around 0.8 at 1 hour. At 5-minutes, the systemwide estimate is over $123 because the expected amount of unserved kWh (the denominator of the equation) is very low for a short-duration outage. As duration increases, cost per unserved kWh decreases precipitously because unserved kWh increases linearly with the number of hours while cost per outage event increases at a decreasing rate.

Table 5-5:
2012 Cost per Unserved kWh Estimates by Region – Residential

Region	Outage Duration	N	Cost per Unserved kWh	95% Confidence Interval	
				Lower Bound	Upper Bound
Bay Area	5 minutes	362	$136.33	$86.50	$186.00
	1 hour	379	$18.89	$13.11	$24.66
	4 hours	403	$6.73	$5.25	$8.21
	8 hours	407	$4.56	$3.67	$5.45
	24 hours	406	$2.24	$1.88	$2.60
Non-Bay Area	5 minutes	417	$99.43	$69.71	$129.14
	1 hour	447	$11.77	$8.55	$14.99
	4 hours	457	$4.00	$3.12	$4.89
	8 hours	475	$2.65	$2.15	$3.15
	24 hours	469	$1.23	$1.04	$1.43
All	5 minutes	779	$123.50	$94.17	$153.00
	1 hour	826	$14.86	$11.80	$17.91
	4 hours	860	$5.08	$4.29	$5.88
	8 hours	882	$3.44	$2.96	$3.92
	24 hours	875	$1.67	$1.47	$1.86

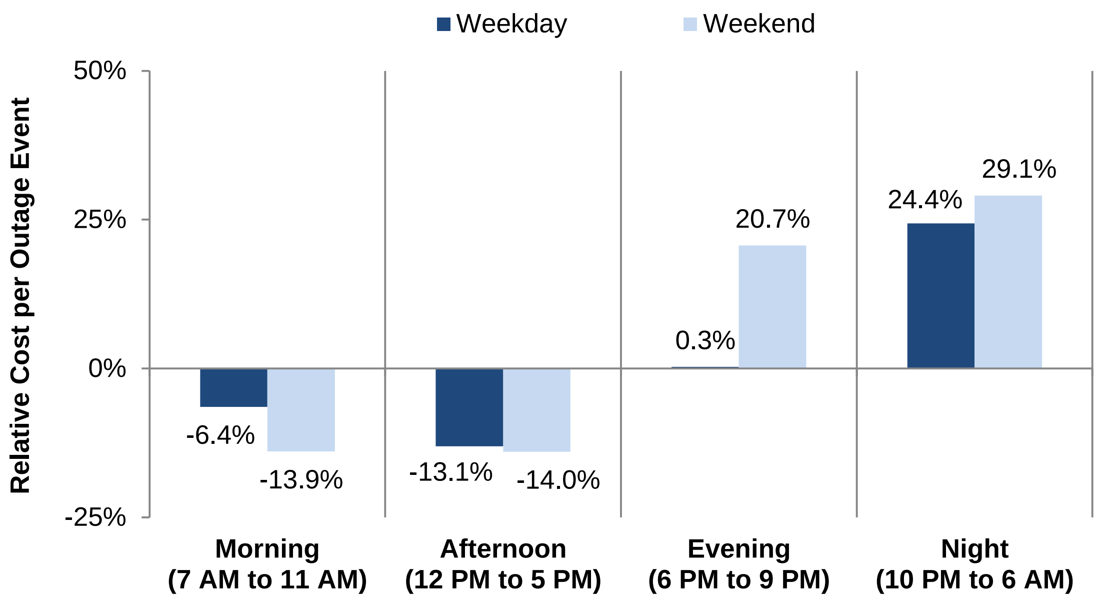
5.3 Impact of Outage Timing

For the residential analysis on the impact of outage timing, onset times were aggregated into 4 key time periods with distinct cost per outage event. These time periods were:

- Morning (7 AM to 11 AM);
- Afternoon (12 PM to 5 PM);
- Evening (6 PM to 9 PM); and
- Night (10 PM to 6 AM).

Figure 5-2 provides the relative cost per outage event estimates, which were derived from the residential customer damage functions described in Appendix B. If a planning application requires an adjustment of outage costs that accounts for onset time, these relative values can be applied to each residential outage cost estimate in Section 5.2 (referred to as the "base value"). As shown in the figure, outage costs for residential customers are somewhat sensitive to onset time, varying from 14% lower than the base value on a weekend afternoon to 29.1% higher on a weekend night. Residential customers also experience relatively high outage costs during weekday nights. Outage costs with onset times in the daytime (morning and afternoon) are lower than the base value. This result is not surprising for daytime on weekdays because fewer people are at home during that time period. It is not as clear why outage costs would be relatively low during daytime on weekends though. Perhaps residential customers are less concerned about a daytime outage because it does not leave them in the dark, which may lead to perceived safety issues or the inconvenience of lighting candles or retrieving flashlights.

Figure 5-2:
Relative Cost per Outage Event Estimates by Day of Week and Onset Time – Residential



5.4 Comparison to Previous Studies

PG&E previously carried out a residential outage cost study in 1993 and 2005. Table 5-6 compares the cost of a 4-hour, summer afternoon outage for each study year. The 1993 and 2005 cost per outage event estimates were converted to 2012 dollars using the gross domestic product deflator, which was obtained from the U.S. Department of Commerce's Bureau of Economic Analysis. Between 1993 and 2005, there was a small increase in reported outage cost for residential customers, but this difference was not statistically significant. The difference between 2005 and 2012 is statistically significant and shows a 64.3% increase in reported outage cost for residential customers since 2005. Although there seems to be an upward trend in outage costs, much of this difference is due to a change in the survey design. In 2005, the highest possible cost estimate for residential customers was $50 because the survey only included outage scenarios up to 8 hours. In the 2012 study, the highest possible cost estimate for residential customers was increased to $200 because the survey included outage scenarios up to 24 hours. This change in the survey design allowed respondents to provide cost estimates in excess of $50 for the 4-hour, summer afternoon outage as well. When given this option, many residential respondents reported outage costs between $50 and $200. Therefore, the 2012 study is a better measure of outage costs for residential customers because the cost estimates are no longer truncated at $50 – a threshold that now seems too low in light of some of the high reported outage costs in the 2012 study. Even with this increase in outage costs in the 2012 study, all of the residential cost per event, average kW and unserved kWh estimates are lower than in the other customer classes.

To adjust for methodological differences, the adjusted 2012 value is provided in Table 5-6 so that an “apples-to-apples” comparison can be made with previous studies. To estimate this value, FSC truncated the 2012 survey data at $50 (adjusted for inflation) before summarizing the results. This adjusted 2012 value is simply provided for comparison to the previous studies and is not recommended for use in planning applications. Using this value in the comparison, there is a smaller increase of 18.4% in reported outage cost for residential customers since 2005. This difference is statistically significant, which suggests that residential outage costs have increased since 2005. This increase may be due to increased household sizes as a result of economic conditions.

Table 5-6:
Cost of a 4-Hour, Summer Afternoon Outage by Study Year – Residential

Study Year	N	Cost per Outage Event (2012$)	95% Confidence Interval	
			Lower Bound	Upper Bound
1993	560	$8.37	$7.35	$9.41
2005	909	$9.31	$8.49	$10.13
2012	858	$15.30	$13.27	$17.33
2012 Adjusted *	858	$11.02	$9.94	$12.09

* This value truncates the 2012 survey data to adjust for methodological differences between the 2005 and 2012 studies. It is simply provided for comparison to the previous studies and is not recommended for use in planning applications.

5.5 Acceptable Level of Service Reliability

In the survey, respondents were asked to rate hypothetical levels of service reliability as acceptable or unacceptable. Each level of service reliability referred to a specific outage duration and frequency. Figure 5-3 shows the percent of residential customers rating each combination of outage frequency and duration as acceptable. As expected, a residential customer’s level of service reliability becomes less acceptable as outage duration increases and the number of outages per year increases. Residential customers are willing to accept a relatively high frequency of short-duration outages. Over 60% of residential customers report that 4 momentary outages per year or 2 outages of 5 to 30 minutes per year are acceptable. One outage of 1 to 4 hours per year is acceptable to 68.8% of residential customers.

Figure 5-3:
Percent of Customers Rating Each Combination of
Outage Frequency and Duration as Acceptable – Residential

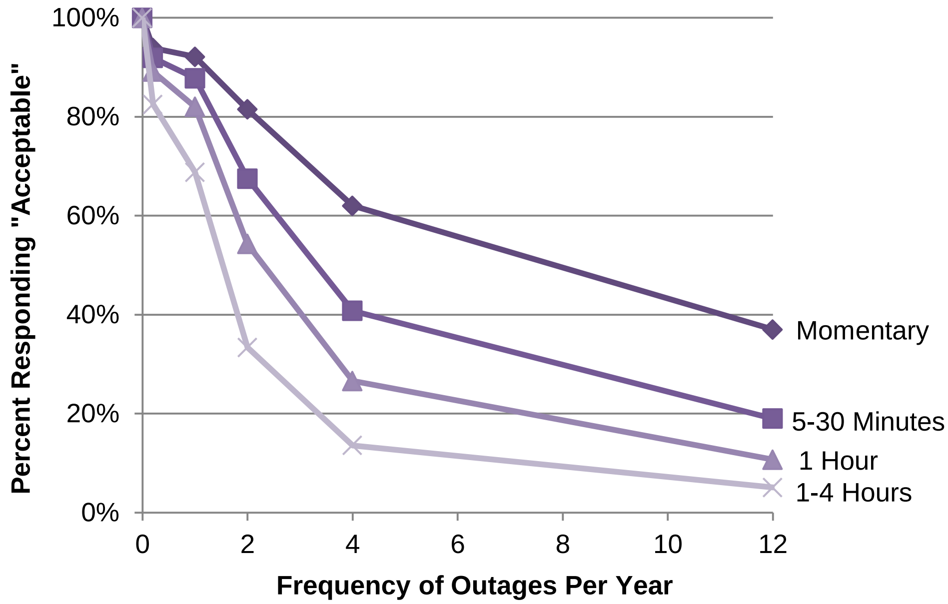


Table 5-7 shows the percent of residential customers rating each combination of outage frequency and duration as acceptable, disaggregated by region. In general, Bay Area residential customers expect a slightly higher level of reliability.

Table 5-7:
Percent of Customers Rating Each Combination of
Outage Frequency and Duration as Acceptable by Region – Residential

Region	Frequency of Outages per Year	Outage Duration			
		Momentary	5-30 Minutes	1 Hour	1-4 Hours
Bay Area	Once every 5 years	94.8%	93.0%	88.4%	81.1%
	1	91.4%	87.3%	79.5%	65.1%
	2	80.0%	64.4%	50.6%	29.3%
	4	60.3%	38.6%	25.1%	14.7%
	12	36.2%	16.7%	9.7%	4.6%
	52	17.7%	6.6%	5.2%	2.4%
Non-Bay Area	Once every 5 years	93.0%	90.7%	89.9%	84.0%
	1	92.7%	88.3%	84.4%	72.8%
	2	82.8%	70.6%	57.9%	37.2%
	4	63.5%	43.3%	28.3%	12.2%
	12	37.8%	21.3%	11.7%	5.6%
	52	20.6%	9.7%	6.1%	3.4%

Region	Frequency of Outages per Year	Outage Duration			
		Momentary	5-30 Minutes	1 Hour	1-4 Hours
All	Once every 5 years	93.9%	91.9%	89.1%	82.5%
	1	92.1%	87.8%	82.0%	68.8%
	2	81.5%	67.5%	54.3%	33.4%
	4	62.0%	40.8%	26.6%	13.6%
	12	37.0%	19.0%	10.7%	5.1%
	52	19.1%	8.1%	5.6%	2.8%

To determine what percent of residential customers receives service that they consider acceptable, the acceptable level of service reliability questions were compared with the number of outages customers reported experiencing over the past 12 months. Table 5-8 provides the results of this analysis by outage duration for the residential survey in 2005 and 2012. In the 2012 study, up to 87% of residential customers reported that they receive service that they say is acceptable. Across all outage durations, these results are very similar to 2005.

Table 5-8:
Percent of Customers Receiving Service Rated as Acceptable by Study Year – Residential

Outage Duration	2005	2012
Momentary	89%	91%
5-30 Minutes	95%	94%
1 Hour	94%	95%
1-4 Hours	85%	87%

Table 5-9 shows how 2 additional measures of satisfaction with service reliability have changed by study year for residential customers. On a 5-point scale, with 1 as "Very Low" and 5 as "Very High," residential customers report a 1.86 average rating for the number of power outages they experience. On a 5-point scale, with 1 as "Very Dissatisfied" and 5 as "Very Satisfied," residential customers report a 3.97 average rating of their satisfaction with the level of service reliability they receive from PG&E. Both of these measures are very similar to the results of the 2005 study.

Table 5-9:
Satisfaction with Service Reliability by Study Year – Residential

Question	Study Year		
	1993	2005	2012
Do you feel the number of power outages your residence experiences is … (5-point scale, 1 for "Very Low" to 5 for "Very High")	2.44	1.88	1.86
How satisfied are you with the reliability of the electrical service you receive from PG&E? (5-point scale, 1 for "Very Dissatisfied" to 5 for "Very Satisfied")	3.94	3.98	3.97

6 Small & Medium Business Results

This section summarizes the results for SMB customers.

6.1 Response to Survey

Table 6-1 summarizes the survey response for SMB customers. With 1,084 total completed surveys, customer response was above the overall sample design target of 1,000. Overall, the survey had a 20.7% response rate that was slightly lower in the Bay Area than non-Bay Area region. The response rate was relatively constant across region and usage category, varying moderately from 17.4% to 24.7%. Low usage SMB customers with average demand below 4 kW were more likely to respond to the survey and had a response rate above 23% within each region. However, non-response bias among higher usage residential customers is not a significant concern for the results because usage category is factored into the stratification weights in the analysis. Appendix C provides a more detailed assessment of the potential sources of non-response bias among SMB customers.

Table 6-1:
Customer Survey Response Summary – SMB

Region	Usage Category (Average kW)	Population	Sample Design Target	Records Sampled	Responses	Response Rate
Bay Area	0 to 4	72,700	140	685	158	23.1%
	4 to 13	44,431	93	494	96	19.4%
	13 to 46	30,790	113	574	117	20.4%
	46 to 222	14,034	120	736	128	17.4%
	222 to 884	4,904	122	696	138	19.8%
	Bay Area Overall	*166,859*	*588*	*3,185*	*637*	*20.0%*
Non-Bay Area	0 to 4	95,231	122	533	131	24.6%
	4 to 13	49,670	68	359	71	19.8%
	13 to 46	31,331	78	340	84	24.7%
	46 to 222	14,010	81	452	90	19.9%
	222 to 884	3,749	63	375	71	18.9%
	Non-Bay Area Overall	*193,991*	*412*	*2,059*	*447*	*21.7%*
Overall		**360,850**	**1,000**	**5,244**	**1,084**	**20.7%**

6.2 2012 Outage Cost Estimates

Figure 6-1 and Table 6-2 provide the SMB cost per outage event estimates. For a 1-hour outage, SMB customers experience a cost of $1,848.8. SMB cost per outage event increases to $10,568.7 at 8 hours and $21,339.4 for a 24-hour outage. The percentage difference between Bay Area and non-Bay Area SMB cost per outage event is substantially greater than in the residential segment. Across all outage durations, Bay Area SMB customers report 2.4 to 4 times higher costs than non-Bay Area customers.

Figure 6-1:
2012 Cost per Outage Event Estimates by Region – SMB

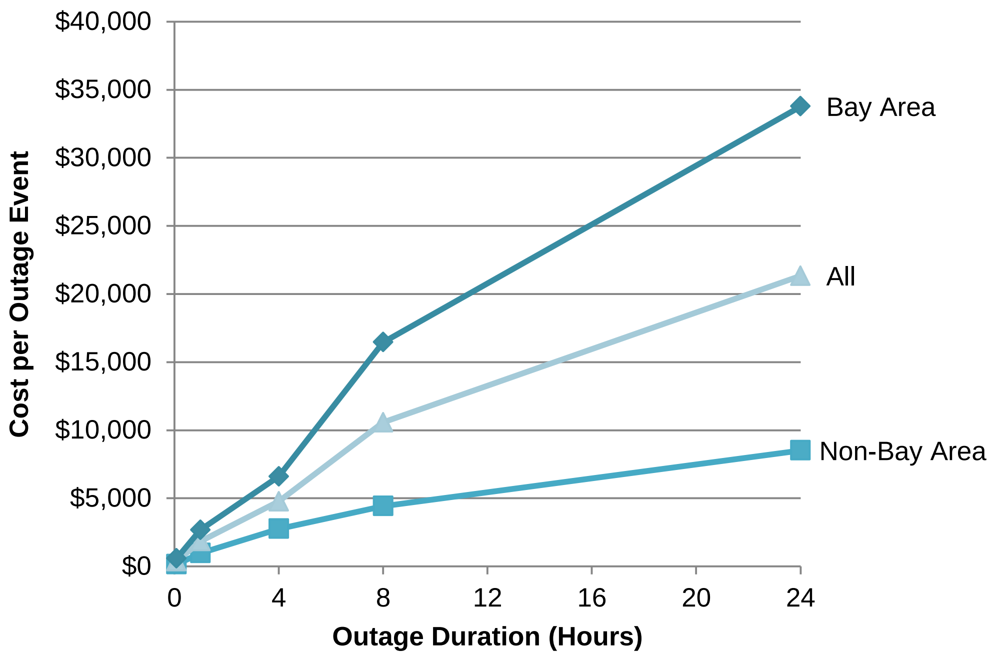


Table 6-2:
2012 Cost per Outage Event Estimates by Region – SMB

Region	Outage Duration	N	Cost per Outage Event	95% Confidence Interval	
				Lower Bound	Upper Bound
Bay Area	5 minutes	631	$585.2	$277.3	$893.2
	1 hour	629	$2,679.4	$1,431.3	$3,927.5
	4 hours	630	$6,607.7	$4,275.2	$8,940.2
	8 hours	630	$16,463.6	$7,286.9	$25,640.2
	24 hours	629	$33,780.9	$13,473.5	$54,088.2
Non-Bay Area	5 minutes	445	$159.0	$103.7	$214.3
	1 hour	442	$973.9	$476.7	$1,471.1
	4 hours	442	$2,761.1	$1,559.0	$3,963.2
	8 hours	445	$4,435.0	$2,611.2	$6,258.7
	24 hours	444	$8,514.5	$4,551.8	$12,477.1
All	5 minutes	1076	$379.8	$223.9	$535.8
	1 hour	1071	$1,848.8	$1,186.3	$2,511.3
	4 hours	1072	$4,774.3	$3,445.6	$6,103.0
	8 hours	1075	$10,568.7	$5,921.4	$15,216.0
	24 hours	1073	$21,339.4	$10,976.6	$31,702.2

Table 6-3 summarizes SMB cost per average kW. For a 1-hour outage, SMB customers experience a cost of $205.2 per average kW. The cost per average kW estimates are substantially lower than the cost per outage event estimates because average demand for SMB respondents was around 9 kW. Considering that Bay Area SMB respondents had slightly higher average demand, the difference with non-Bay Area customers is lower when normalized by average kW. Nonetheless, Bay Area SMB customers report 2.1 to 3.2 times higher cost per average kW than non-Bay Area customers.

Table 6-3:
2012 Cost per Average kW Estimates by Region – SMB

Region	Outage Duration	N	Cost per Average kW	95% Confidence Interval	
				Lower Bound	Upper Bound
Bay Area	5 minutes	631	$62.1	$29.4	$94.7
	1 hour	629	$272.0	$145.3	$398.7
	4 hours	630	$706.0	$456.8	$955.1
	8 hours	630	$1,560.5	$690.7	$2,430.3
	24 hours	629	$3,482.6	$1,389.0	$5,576.1
Non-Bay Area	5 minutes	445	$19.8	$12.9	$26.7
	1 hour	442	$121.9	$59.7	$184.1
	4 hours	442	$339.2	$191.5	$486.9
	8 hours	445	$557.9	$328.5	$787.3
	24 hours	444	$1,073.7	$574.0	$1,573.4
All	5 minutes	1076	$43.3	$25.5	$61.0
	1 hour	1071	$205.2	$131.7	$278.7
	4 hours	1072	$540.1	$389.8	$690.4
	8 hours	1075	$1,136.4	$636.7	$1,636.1
	24 hours	1073	$2,403.1	$1,236.1	$3,570.1

Table 6-4 provides the SMB cost per unserved kWh estimates. For a 1-hour outage, SMB customers experience a cost of $195.6 per unserved kWh, which is similar to the cost per average kW estimate because the expected amount of unserved kWh is also around 9 at 1 hour. At 5-minutes, the systemwide estimate is over $490 because the expected amount of unserved kWh (the denominator of the equation) is very low for a short-duration outage. As duration increases, cost per unserved kWh decreases precipitously because unserved kWh increases linearly with the number of hours while cost per outage event increases at a decreasing rate.

Table 6-4:
2012 Cost per Unserved kWh Estimates by Region – SMB

Region	Outage Duration	N	Cost per Unserved kWh	95% Confidence Interval	
				Lower Bound	Upper Bound
Bay Area	5 minutes	631	$713.7	$338.2	$1,089.2
	1 hour	629	$261.4	$139.6	$383.2
	4 hours	630	$168.3	$108.9	$227.7
	8 hours	630	$192.4	$85.2	$299.7
	24 hours	629	$144.5	$57.6	$231.3
Non-Bay Area	5 minutes	445	$227.2	$148.2	$306.2
	1 hour	442	$114.7	$56.1	$173.3
	4 hours	442	$79.3	$44.7	$113.8
	8 hours	445	$66.5	$39.1	$93.8
	24 hours	444	$44.5	$23.8	$65.3
All	5 minutes	1076	$493.3	$290.7	$695.8
	1 hour	1071	$195.6	$125.5	$265.7
	4 hours	1072	$127.5	$92.0	$163.0
	8 hours	1075	$138.4	$77.5	$199.2
	24 hours	1073	$99.7	$51.3	$148.1

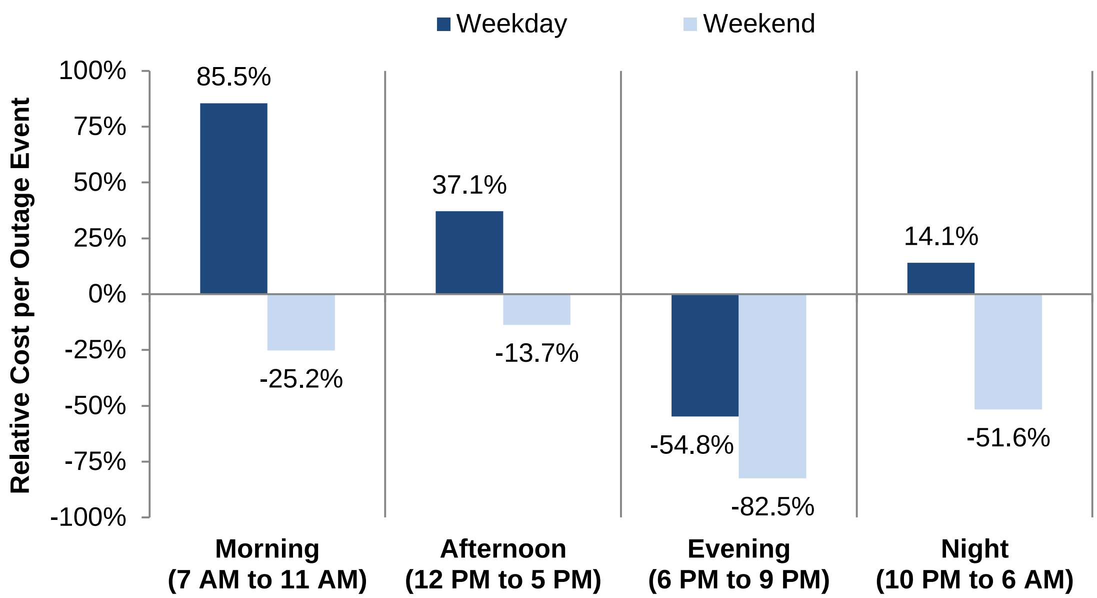
6.3 Impact of Outage Timing

For the SMB analysis on the impact of outage timing, onset times were aggregated into 4 key time periods with distinct cost per outage event. These time periods were:

- Morning (7 AM to 11 AM);
- Afternoon (12 PM to 5 PM);
- Evening (6 PM to 9 PM); and
- Night (10 PM to 6 AM).

Figure 6-2 provides the relative cost per outage event estimates, which were derived from the SMB customer damage functions described in Appendix B. If a planning application requires an adjustment of outage costs that accounts for onset time, these relative values can be applied to each SMB outage cost estimate in Section 6.2 (referred to as the "base value"). As shown in the figure, outage costs for SMB customers are highly sensitive to onset time, varying from 82.5% lower than the base value on a weekend evening to 85.5% higher on a weekday morning. The only weekday outages that have lower costs than the base value are those with an evening onset time because these outages begin after normal business hours and likely end before business resumes the next day. Outages with a weekday morning onset time have the highest cost because these outages likely start and end during normal business hours, potentially disrupting an entire day of work. Although some SMB customers such as retail stores likely have higher costs on a weekend day, the overall trend shows that outage costs are lower than the base value for all weekend onset times. Considering that SMB outage costs vary substantially depending on the onset time, it is important that planning applications apply these relative values.

Figure 6-2:
Relative Cost per Outage Event Estimates by Day of Week and Onset Time – SMB



6.4 Comparison to Previous Studies

PG&E previously carried out an SMB outage cost study in 1993 and 2005. Table 6-5 compares the cost of a 4-hour, summer afternoon outage for each study year. The 1993 and 2005 cost per outage event estimates were converted to 2012 dollars using the gross domestic product deflator, which was obtained from the U.S. Department of Commerce's Bureau of Economic Analysis. Between 1993 and 2005, there was a decrease in reported outage cost for SMB customers, but this difference was not statistically significant. The difference between 2005 and 2012 is also not statistically significant, even though there is a 58% increase in average cost per outage event. Given the underlying high variability of reported outage costs from customer to customer, large differences in average values are required to detect a statistically significant difference. In this case, the results are inconclusive.

Table 6-5:
Cost of a 4-Hour, Summer Afternoon Outage by Study Year – SMB

Study Year	N	Cost per Outage Event (2012$)	95% Confidence Interval	
			Lower Bound	Upper Bound
1993	684	$4,738.3	$2,651.6	$6,825.0
2005	784	$3,884.4	$3,045.0	$4,722.7
2012	1074	$6,138.9	$3,541.9	$8,735.8

6.5 Acceptable Level of Service Reliability

In the survey, respondents were asked to rate hypothetical levels of service reliability as acceptable or unacceptable. Each level of service reliability referred to a specific outage duration and frequency. Figure 6-3 shows the percent of SMB customers rating each combination of outage frequency and duration as acceptable. As expected, an SMB customer's level of service reliability becomes less acceptable as outage duration increases and the number of outages per year increases. SMB customers are willing to accept a relatively high frequency of short-duration outages. A majority of SMB customers reports that 4 momentary outages per year is acceptable. One outage of 1 to 4 hours per year is acceptable to 49% of SMB customers.

Figure 6-3:
Percent of Customers Rating Each Combination of Outage Frequency and Duration as Acceptable – SMB

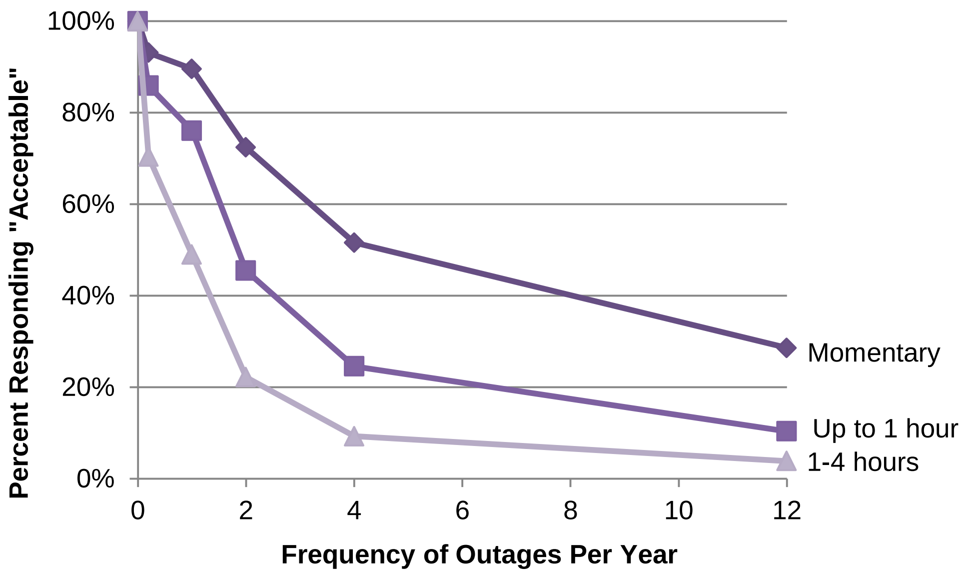


Table 6-6 shows the percent of SMB customers rating each combination of outage frequency and duration as acceptable, disaggregated by region. In general, Bay Area SMB customers expect a slightly higher level of reliability.

Table 6-6:
Percent of Customers Rating Each Combination of Outage Frequency and Duration as Acceptable by Region – SMB

Region	Frequency of Outages per Year	Outage Duration		
		Momentary	Up to 1 Hour	1-4 Hours
Bay Area	Once every 5 years	92.6%	84.7%	68.5%
	1	88.6%	73.2%	43.2%
	2	67.4%	40.0%	16.7%
	4	46.4%	22.0%	8.1%
	12	24.9%	10.5%	3.8%
	52	14.9%	5.6%	1.8%

Region	Frequency of Outages per Year	Outage Duration		
		Momentary	Up to 1 Hour	1-4 Hours
Non-Bay Area	Once every 5 years	93.5%	86.9%	71.8%
	1	90.2%	78.3%	53.8%
	2	76.5%	49.9%	26.9%
	4	55.6%	26.6%	10.2%
	12	31.4%	10.4%	4.1%
	52	17.4%	5.1%	2.9%
All	Once every 5 years	93.1%	85.9%	70.4%
	1	89.6%	76.1%	49.0%
	2	72.4%	45.5%	22.2%
	4	51.6%	24.6%	9.3%
	12	28.6%	10.4%	3.9%
	52	16.3%	5.3%	2.5%

To determine what percent of SMB customers receives service that they consider acceptable, the acceptable level of service reliability questions were compared with the number of outages customers reported experiencing over the past 12 months. Table 6-7 provides the results of this analysis by outage duration for the SMB survey in 2005 and 2012. In the 2012 study, up to 81% of SMB customers reported that they receive service that they say is acceptable. Across all outage durations, these results are very similar to 2005.

Table 6-7:
Percent of Customers Receiving Service Rated as Acceptable by Study Year – SMB

Outage Duration	2005	2012
Momentary	88%	87%
Up to 1 Hour	83%	85%
1-4 Hours	82%	81%

7 Large Business Results

This section summarizes the results for large business customers.

7.1 Response to Survey

Table 7-1 summarizes the survey response for large business customers. With 210 total completed surveys, customer response was above the overall sample design target of 190. Overall, the survey had a 32.1% response rate that was relatively higher in the Bay Area. In both regions, the response rate increased as usage increased. Bay Area customers in the largest usage category provided a 61.2% response rate, which was substantially higher than any other category. Considering that usage category and region are factored into the stratifications weights in the analysis, non-response bias among these categories is not a significant concern. Appendix C provides a more detailed assessment of the potential sources of non-response bias among large business customers.

Table 7-1:
Customer Survey Response Summary – Large Business

Region	Usage Category (Average kW)	Population	Sample Design Target	Records Sampled	Responses	Response Rate
Bay Area	0 to 600	145	25	101	27	26.7%
	600 to 1,268	295	26	96	30	31.3%
	1,268 to 2,981	134	21	91	32	35.2%
	2,981 to 65,791	56	45	49	30	61.2%
	Bay Area Overall	*630*	*117*	*337*	*119*	*35.3%*
Non-Bay Area	0 to 600	241	28	122	29	23.8%
	600 to 1,268	157	6	28	7	25.0%
	1,268 to 2,981	143	14	115	37	32.2%
	2,981 to 65,791	54	25	53	18	34.0%
	Non-Bay Area Overall	*595*	*73*	*318*	*91*	*28.6%*
Overall		**1,225**	**190**	**655**	**210**	**32.1%**

7.2 2012 Outage Cost Estimates

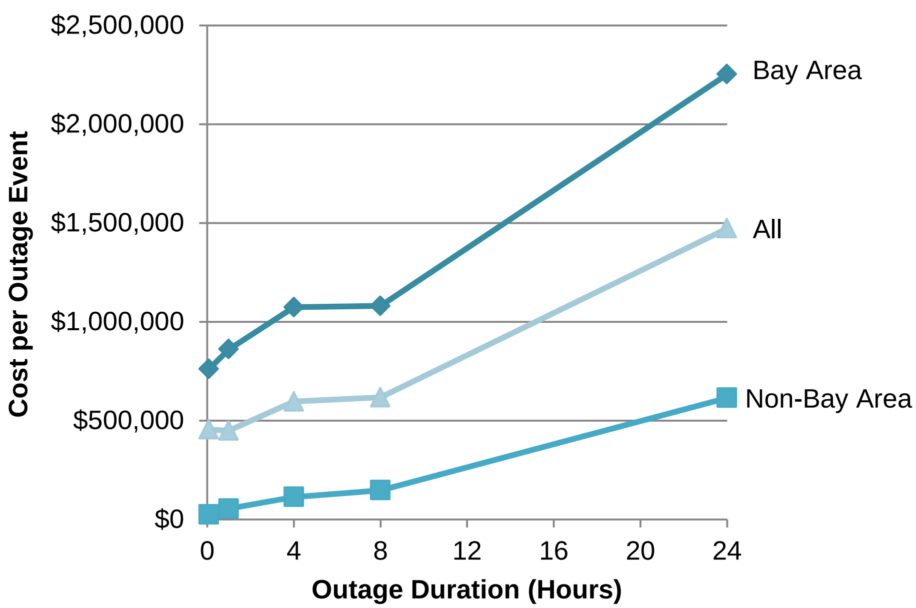
Figure 7-1 and Table 7-2 provide the large business cost per outage event estimates. For a 1-hour outage, large business customers experience a cost of $449,655. Large business cost per outage event increases to $617,196 at 8 hours and $1,472,497 for a 24-hour outage. The confidence intervals for these estimates are quite wide because the large business segment had a smaller sample size and much more variable outage cost estimates from customer to customer. The variability of outage costs was particularly high in the Bay Area, which had a subset of large business customers with extremely high costs, even for a 5-minute outage. This subset of Bay Area customers drives much of the difference between regions, but because of the wide confidence intervals as a result of the relatively small sample size and high variability in outage costs, the regional differences are not statistically significant.

The extremely high outage costs for some of the large business customers in the Bay Area must be understood within the context of their level of reliability. Many of these Bay Area large business customers are accustomed to a very high level of reliability and rarely experience sustained power interruptions, so even a 5-minute outage would impose extremely high costs. Considering that these customers are significantly less likely to experience transmission or distribution related power interruptions, it can be argued that their costs should be excluded from many transmission and distribution planning applications. Therefore, Appendix D provides the 2012 large business outage cost estimates by level of service reliability. For transmission and distribution planning applications, FSC recommends applying the results segmented by level of reliability as opposed to region.[12] This segmentation of the analysis should be carried out as follows:

- If a planning analysis focuses on a circuit or transmission line that has performed badly in the past, which is often the focus of these types of planning analyses, FSC recommends applying the outage cost estimates associated with large business customers that have experienced a sustained outage in the past year.
- If a planning analysis focuses on a circuit or transmission line that has performed well in the past, FSC recommends applying the outage cost estimates associated with large business customers that have not experienced a sustained outage in the past year.

For generation planning, FSC recommends applying the outage cost estimates for all large business customers because supply shortages usually have a similar impact on all customers systemwide.

Figure 7-1:
2012 Cost per Outage Event Estimates by Region – Large Business



[12] Another option is to apply to results segmented by level of reliability *and* region, but with the relatively small sample sizes in the large business segment, it is not recommended to divide the results into such granular categories.

Table 7-2:
2012 Cost per Outage Event Estimates by Region – Large Business

Region	Outage Duration	N	Cost per Outage Event	95% Confidence Interval	
				Lower Bound	Upper Bound
Bay Area	5 minutes	119	$761,784	-$90,608	$1,614,177
	1 hour	119	$861,359	$25,312	$1,697,407
	4 hours	120	$1,073,743	$223,315	$1,924,171
	8 hours	120	$1,080,310	$283,933	$1,876,688
	24 hours	120	$2,252,293	$802,979	$3,701,606
Non-Bay Area	5 minutes	90	$24,308	$10,812	$37,804
	1 hour	90	$54,970	$28,648	$81,292
	4 hours	90	$113,746	$52,625	$174,868
	8 hours	90	$147,383	$82,122	$212,644
	24 hours	90	$615,402	$184,438	$1,046,366
All	5 minutes	209	$454,675	-$54,092	$963,442
	1 hour	209	$449,655	$51,936	$847,375
	4 hours	210	$596,675	$178,277	$1,015,072
	8 hours	210	$617,196	$231,787	$1,002,605
	24 hours	210	$1,472,497	$682,564	$2,262,429

Table 7-3 summarizes large business cost per average kW. For a 1-hour outage, large business customers experience a cost of $327.4 per average kW. The percentage difference between Bay Area and non-Bay Area large business cost per average kW is substantially greater than in any other segment. For a 5-minute outage, Bay Area cost per average kW is 32 times higher than in the non-Bay Area. The percentage difference decreases as duration increases and at 24 hours, Bay Area cost per average kW is 3.8 times higher than in the non-Bay Area.

Table 7-3:
2012 Cost per Average kW Estimates by Region – Large Business

Region	Outage Duration	N	Cost per Average kW	95% Confidence Interval	
				Lower Bound	Upper Bound
Bay Area	5 minutes	119	$547.5	-$65.1	$1,160.2
	1 hour	119	$624.7	$18.4	$1,231.0
	4 hours	120	$774.6	$161.1	$1,388.2
	8 hours	120	$771.0	$202.6	$1,339.4
	24 hours	120	$1,663.5	$593.1	$2,734.0
Non-Bay Area	5 minutes	90	$17.0	$7.6	$26.5
	1 hour	90	$40.7	$21.2	$60.2
	4 hours	90	$85.6	$39.6	$131.6
	8 hours	90	$110.1	$61.4	$158.9
	24 hours	90	$443.4	$132.9	$753.9

Region	Outage Duration	N	Cost per Average kW	95% Confidence Interval	
				Lower Bound	Upper Bound
All	5 minutes	209	$319.3	-$38.0	$676.5
	1 hour	209	$327.4	$37.8	$617.0
	4 hours	210	$436.9	$130.5	$743.2
	8 hours	210	$449.7	$168.9	$730.6
	24 hours	210	$1,047.5	$485.6	$1,609.5

Table 7-4 provides the large business cost per unserved kWh estimates. For a 1-hour outage, large business customers experience a cost of $318.5 per unserved kWh. At 5-minutes, the systemwide estimate is nearly $3,770 because the expected amount of unserved kWh (the denominator of the equation) is very low for a short-duration outage. In addition, many of the Bay Area large business customers have extremely high costs, even for a 5-minute outage, because they are accustomed to a very high level of reliability and rarely experience sustained power interruptions, as discussed above. As duration increases, cost per unserved kWh decreases precipitously because unserved kWh increases linearly with the number of hours while cost per outage event increases at a decreasing rate. In fact, many of the high-cost large business customers have the same or very similar costs for a 5-minute outage and a 24-hour outage.

Table 7-4:
2012 Cost per Unserved kWh Estimates by Region – Large Business

Region	Outage Duration	N	Cost per Unserved kWh	95% Confidence Interval	
				Lower Bound	Upper Bound
Bay Area	5 minutes	119	$6,486.6	-$771.5	$13,744.7
	1 hour	119	$609.7	$17.9	$1,201.4
	4 hours	120	$189.9	$39.5	$340.4
	8 hours	120	$94.8	$24.9	$164.7
	24 hours	120	$69.1	$24.6	$113.5
Non-Bay Area	5 minutes	90	$201.5	$89.6	$313.3
	1 hour	90	$39.4	$20.5	$58.3
	4 hours	90	$21.2	$9.8	$32.6
	8 hours	90	$13.7	$7.6	$19.8
	24 hours	90	$18.5	$5.6	$31.5
All	5 minutes	209	$3,769.8	-$448.5	$7,988.1
	1 hour	209	$318.5	$36.8	$600.2
	4 hours	210	$107.5	$32.1	$182.8
	8 hours	210	$55.6	$20.9	$90.4
	24 hours	210	$43.7	$20.3	$67.2

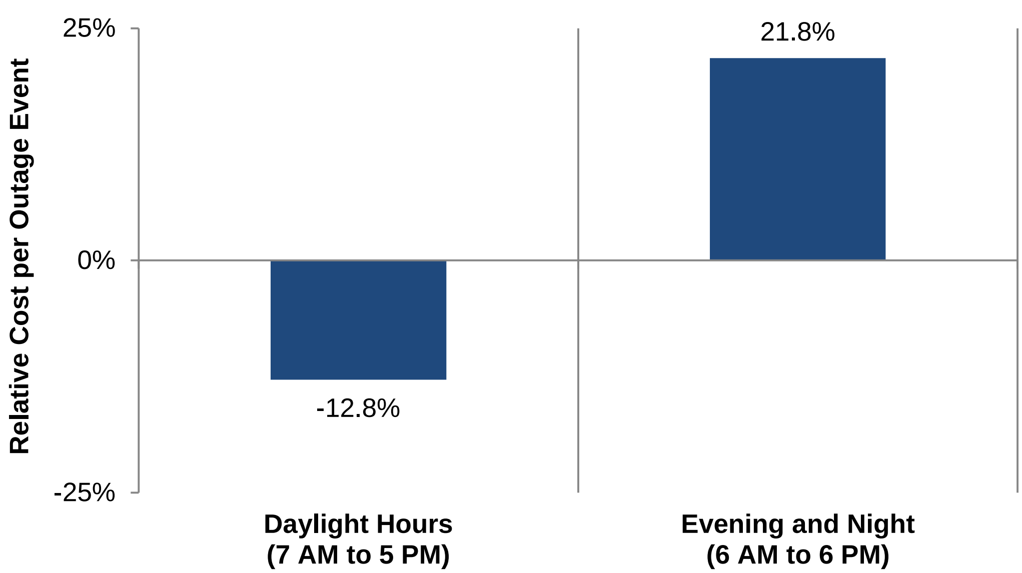
7.3 Impact of Outage Timing

For the large business analysis on the impact of outage timing, onset times were aggregated into 2 key time periods with distinct cost per outage event. These time periods were:

- Daylight Hours (7 AM to 5 PM); and
- Evening and Night (6 PM to 6 AM).

Figure 7-2 provides the relative cost per outage event estimates, which were derived from the large business customer damage functions described in Appendix B. Unlike the other 3 customer segments, the onset times were not further divided by day of week because this variable did not have a significant effect for large business customers. If a planning application requires an adjustment of outage costs that accounts for onset time, these relative values can be applied to each large business outage cost estimate in Section 7.2 (referred to as the "base value"). As shown in the figure, outage costs for large business customers are somewhat sensitive to onset time, varying moderately from 12.8% lower than the base value during daylight hours to 21.8% higher during the evening and night. Considering that many large business customers operate 24 hours per day, 7 days per week, outages with different onset times likely have a similar impact on production. Even though the impact on production is similar, the overall outage cost may be greater during the evening and night because outage response may require overtime or emergency staff.

Figure 7-2:
Relative Cost per Outage Event Estimates by Onset Time – Large Business



7.4 Comparison to Previous Studies

PG&E previously carried out a large business outage cost study in 1989 and 2005. Table 7-5 compares the cost of a 4-hour, summer afternoon outage for each study year. The 1989 and 2005 cost per outage event estimates were converted to 2012 dollars using the gross domestic product deflator, which was obtained from the U.S. Department of Commerce's Bureau of Economic Analysis.

Between 1989 and 2005, there was a 53.3% increase in reported outage cost for large business customers, but this difference was not statistically significant. The difference between 2005 and 2012 is statistically significant and shows a 4-fold increase in reported outage cost for large business customers since 2005.[13]

While it is possible that outage costs for large business customers have increased significantly since 2005, the results reported here must be used with caution. With the relatively small sample sizes for the large business segment and specific subset of customers with extremely high outage costs, the results for each large business study are subject to large statistical error because they are highly sensitive to the sample that is randomly selected. In the 2012 study, it seems that the random sample included a larger amount of these customers with extremely high outage costs. In addition, the 2012 study had lower large business response rates than those of the 1989 and 2005 studies, which may have led to non-response bias. Although the assessment presented in Appendix D did not find any observable factors (such as industry type) that led to non-response bias, there could have been unobservable factors that biased the results upward in light of the relatively low response rates in the 2012 study. Another possibility may be that these high-cost customers are more prevalent in PG&E's large business population than they were in the past, which may require further research.

Table 7-5:
Cost of a 4-Hour, Summer Afternoon Outage by Study Year – Large Business

Study Year	N	Cost per Outage Event (2012$)	95% Confidence Interval	
			Lower Bound	Upper Bound
1989	372	$73,948	$53,045	$94,852
2005	143	$113,336	$69,959	$156,714
2012	210	$460,263	$131,708	$788,819

7.5 Acceptable Level of Service Reliability

In the survey, respondents were asked to rate hypothetical levels of service reliability as acceptable or unacceptable. Each level of service reliability referred to a specific outage duration and frequency. Figure 7-3 shows the percent of large business customers rating each combination of outage frequency and duration as acceptable. As expected, a large business customer's level of service reliability becomes less acceptable as outage duration increases and the number of outages per year increases. Even though cost per unserved kWh for outages longer than 1 hour is lower for large business customers than it is for SMB customers, large business customers expect a substantially higher level of reliability. One outage of 1 to 4 hours per year is acceptable to 23.6% of large business customers, compared to 49% of SMB customers. A single sustained outage more than 5 minutes per year is considered unacceptable for a majority of large business customers. Two momentary outages is considered unacceptable by the majority.

[13] Note that statistical significance in this case implies that there was an increase in reported cost, but does not necessarily confirm that the magnitude of the increase was exactly 4-fold.

Figure 7-3:
Percent of Customers Rating Each Combination of
Outage Frequency and Duration as Acceptable – Large Business

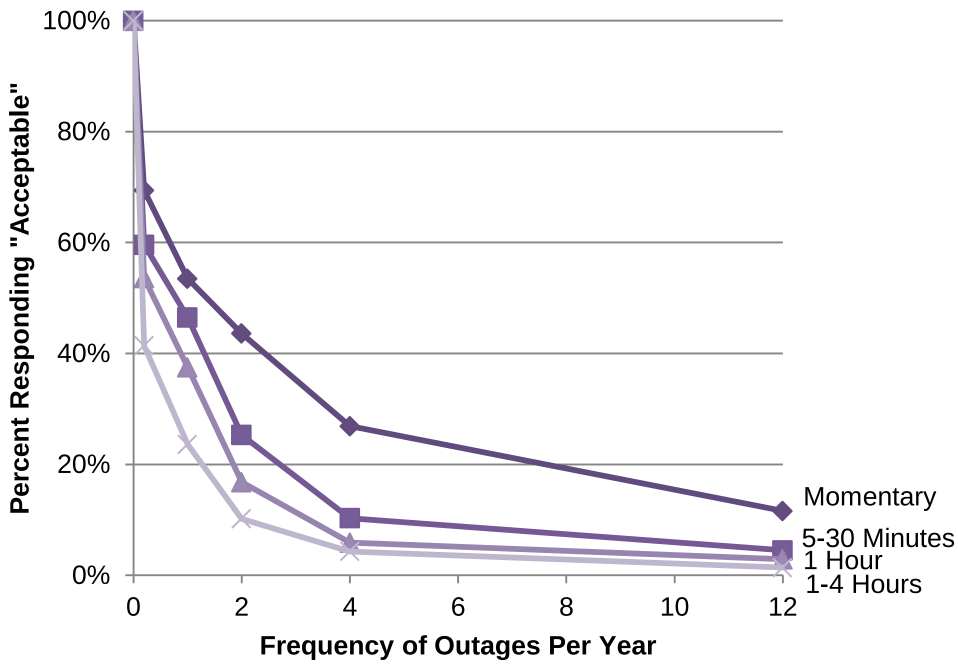


Table 7-6 shows the percent of large business customers rating each combination of outage frequency and duration as acceptable, disaggregated by region. This is the only segment for which there is a substantial difference in the acceptable level of service reliability by region. Bay Area large business customers expect a very high level of service reliability. Over 40% of Bay Area large business customers report that a single momentary outage every 5 years is unacceptable, compared to 23.6% in the non-Bay Area region. For outages between 5 minutes and 30 minutes, only 35.3% of Bay Area large business customers find it acceptable once per year, compared to 53.7% in the non-Bay Area region. As outage frequency and duration increase, the regional differences are not as large.

Table 7-6:
Percent of Customers Rating Each Combination of
Outage Frequency and Duration as Acceptable by Region – Large Business

Region	Frequency of Outages per Year	Outage Duration			
		Momentary	5-30 Minutes	1 Hour	1-4 Hours
Bay Area	Once every 5 years	59.4%	50.3%	45.1%	33.0%
	1	41.2%	35.3%	31.4%	20.4%
	2	29.5%	18.8%	15.9%	12.4%
	4	15.9%	8.6%	5.3%	4.1%
	12	7.6%	3.4%	3.4%	1.1%
	52	4.6%	3.4%	1.1%	1.8%

Region	Frequency of Outages per Year	Outage Duration			
		Momentary	5-30 Minutes	1 Hour	1-4 Hours
Non-Bay Area	Once every 5 years	76.4%	62.4%	55.8%	47.0%
	1	60.5%	53.7%	41.6%	25.3%
	2	54.0%	28.1%	15.9%	7.4%
	4	32.2%	10.8%	6.2%	4.0%
	12	13.7%	5.1%	2.3%	1.7%
	52	2.2%	0.0%	0.0%	0.0%
All	Once every 5 years	69.4%	59.6%	53.6%	41.4%
	1	53.5%	46.5%	37.5%	23.6%
	2	43.6%	25.3%	16.8%	10.2%
	4	26.9%	10.3%	5.9%	4.3%
	12	11.6%	4.5%	2.9%	1.4%
	52	3.4%	1.6%	0.4%	0.8%

To determine what percent of large business customers receives service that they consider acceptable, the acceptable level of service reliability questions were compared with the number of outages customers reported experiencing over the past 12 months. Table 7-7 provides the results of this analysis by outage duration for the large business survey in 2005 and 2012. In the 2012 study, up to 68% of large business customers reported that they receive service that they say is acceptable. As in the 2005 study, momentary outages for large business customers are the outage duration that most likely leads to unacceptable service.

Table 7-7:
Percent of Customers Receiving Service Rated as Acceptable by Study Year – Large Business

Outage Duration	2005	2012
Momentary	70%	68%
5-30 Minutes	86%	84%
1 Hour	92%	81%
1-4 Hours	78%	73%

8 Agricultural Results

This section summarizes the results for agricultural customers.

8.1 Response to Survey

Table 8-1 summarizes the survey response for agricultural customers. With 538 total completed surveys, customer response was above the overall sample design target of 500. Overall, the survey had a 15.4% response rate that was slightly higher in the Bay Area than non-Bay Area. The response rate was relatively constant across region and usage category, varying moderately from 13.6% to 20%. Considering that the 2 key observable factors of interest in this study – usage and region – did not substantially affect the likelihood that a customer responded to the survey, non-response bias is not a significant concern for the agricultural customer results. Nonetheless, Appendix C provides a more detailed assessment of the potential sources of non-response bias among agricultural customers.

Table 8-1:
Customer Survey Response Summary – Agricultural

Region	Usage Category (Average kW)	Population	Sample Design Target	Records Sampled	Responses	Response Rate
Bay Area	0 to 0.5	1,469	39	276	46	16.7%
	0.5 to 6.2	1,714	43	332	45	13.6%
	6.2 to 5,511	280	33	170	34	20.0%
	Bay Area Overall	*3,463*	*115*	*778*	*125*	*16.1%*
Non-Bay Area	0 to 0.5	22,939	123	804	127	15.8%
	0.5 to 6.2	34,427	143	1,047	159	15.2%
	6.2 to 5,511	15,916	119	859	127	14.8%
	Non-Bay Area Overall	*73,282*	*385*	*2,710*	*413*	*15.2%*
Overall		**76,745**	**500**	**3,488**	**538**	**15.4%**

8.2 2012 Outage Cost Estimates

Figure 8-1 and Table 8-2 provide the agricultural cost per outage event estimates. For a 1-hour outage, agricultural customers experience a cost of $453.5. Agricultural cost per outage event increases to $2,549 at 8 hours and $5,842 for a 24-hour outage. Since over 95% of agricultural customers are outside of the Bay Area, the outage cost estimates for all customers closely match those of non-Bay Area agricultural customers. Bay Area agricultural customers report higher costs than non-Bay Area customers for outages of 4 hours or longer and lower costs than non-Bay Area customers for outages of 5 minutes and 1 hour.

Figure 8-1:
2012 Cost per Outage Event Estimates by Region – Agricultural

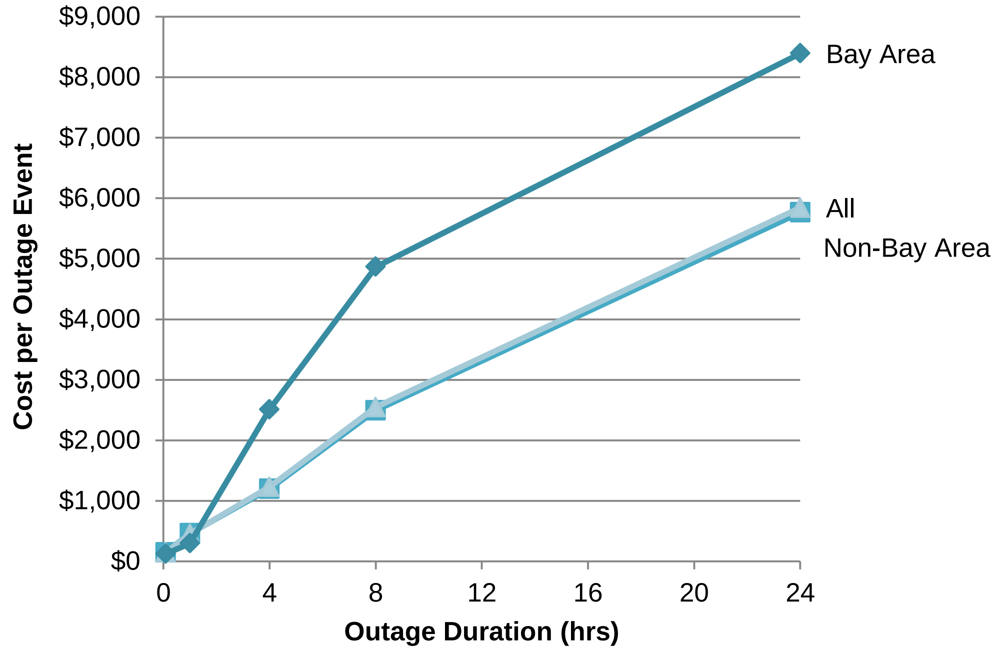


Table 8-2:
2012 Cost per Outage Event Estimates by Region – Agricultural

Region	Outage Duration	N	Cost per Outage Event	95% Confidence Interval	
				Lower Bound	Upper Bound
Bay Area	5 minutes	106	$124.1	$0.2	$248.1
	1 hour	104	$299.3	$156.6	$442.1
	4 hours	101	$2,512.2	-$72.9	$5,097.3
	8 hours	100	$4,866.9	$1,343.6	$8,390.2
	24 hours	97	$8,392.1	$3,467.0	$13,317.1
Non-Bay Area	5 minutes	345	$147.5	$82.8	$212.2
	1 hour	337	$461.6	$207.2	$715.9
	4 hours	324	$1,201.5	$756.0	$1,646.9
	8 hours	324	$2,496.6	$1,644.8	$3,348.4
	24 hours	322	$5,763.9	$3,180.1	$8,347.7
All	5 minutes	451	$146.1	$84.5	$207.7
	1 hour	441	$453.5	$212.6	$694.5
	4 hours	425	$1,230.7	$802.9	$1,658.4
	8 hours	424	$2,549.4	$1,721.7	$3,377.2
	24 hours	419	$5,842.4	$3,289.2	$8,395.6

Table 8-3 summarizes agricultural cost per average kW. For a 1-hour outage, agricultural customers experience a cost of $52.1 per average kW. The cost per average kW estimates are substantially lower than the cost per outage event estimates because average demand for agricultural respondents was around 8.5 kW. As in the cost per outage event estimates, Bay Area agricultural customers report higher costs than non-Bay Area customers for outages of 4 hours or longer and lower costs than non-Bay Area customers for outages of 5 minutes and 1 hour.

Table 8-3:
2012 Cost per Average kW Estimates by Region – Agricultural

Region	Outage Duration	N	Cost per Average kW	95% Confidence Interval	
				Lower Bound	Upper Bound
Bay Area	5 minutes	106	$12.8	$0.0	$25.5
	1 hour	104	$44.4	$23.2	$65.6
	4 hours	101	$356.8	-$10.3	$724.0
	8 hours	100	$682.6	$188.4	$1,176.7
	24 hours	97	$1,143.3	$472.3	$1,814.3
Non-Bay Area	5 minutes	345	$18.2	$10.2	$26.2
	1 hour	337	$52.5	$23.6	$81.4
	4 hours	324	$138.1	$86.9	$189.3
	8 hours	324	$281.8	$185.6	$377.9
	24 hours	322	$686.2	$378.6	$993.8
All	5 minutes	451	$18.1	$10.5	$25.7
	1 hour	441	$52.1	$24.4	$79.8
	4 hours	425	$143.9	$93.9	$194.0
	8 hours	424	$288.7	$195.0	$382.5
	24 hours	419	$700.5	$394.4	$1,006.7

Table 8-4 provides the agricultural cost per unserved kWh estimates. For a 1-hour outage, agricultural customers experience a cost of $50.3 per unserved kWh, which is similar to the cost per average kW estimate because the expected amount of unserved kWh is also around 8.5 at 1 hour. Agricultural cost per unserved kWh is substantially lower than in the SMB segment. Even though agricultural and SMB respondents had roughly equivalent average usage, agricultural cost per unserved kWh is 58.3% lower at 5 minutes and 71% to 74% lower for outages lasting an hour or more. Agricultural customers clearly place a lower value on lost load than SMB customers of a similar size.

Table 8-4:
2012 Cost per Unserved kWh Estimates by Region – Agricultural

Region	Outage Duration	N	Cost per Unserved kWh	95% Confidence Interval	
				Lower Bound	Upper Bound
Bay Area	5 minutes	106	$144.3	$0.2	$288.4
	1 hour	104	$42.5	$22.2	$62.8
	4 hours	101	$89.5	-$2.6	$181.7
	8 hours	100	$84.6	$23.4	$145.8
	24 hours	97	$48.1	$19.9	$76.3
Non-Bay Area	5 minutes	345	$207.8	$116.6	$298.9
	1 hour	337	$50.7	$22.8	$78.7
	4 hours	324	$34.2	$21.5	$46.9
	8 hours	324	$35.0	$23.1	$47.0
	24 hours	322	$28.2	$15.5	$40.8
All	5 minutes	451	$205.7	$118.9	$292.5
	1 hour	441	$50.3	$23.6	$77.0
	4 hours	425	$35.6	$23.2	$48.0
	8 hours	424	$35.9	$24.3	$47.6
	24 hours	419	$28.8	$16.2	$41.4

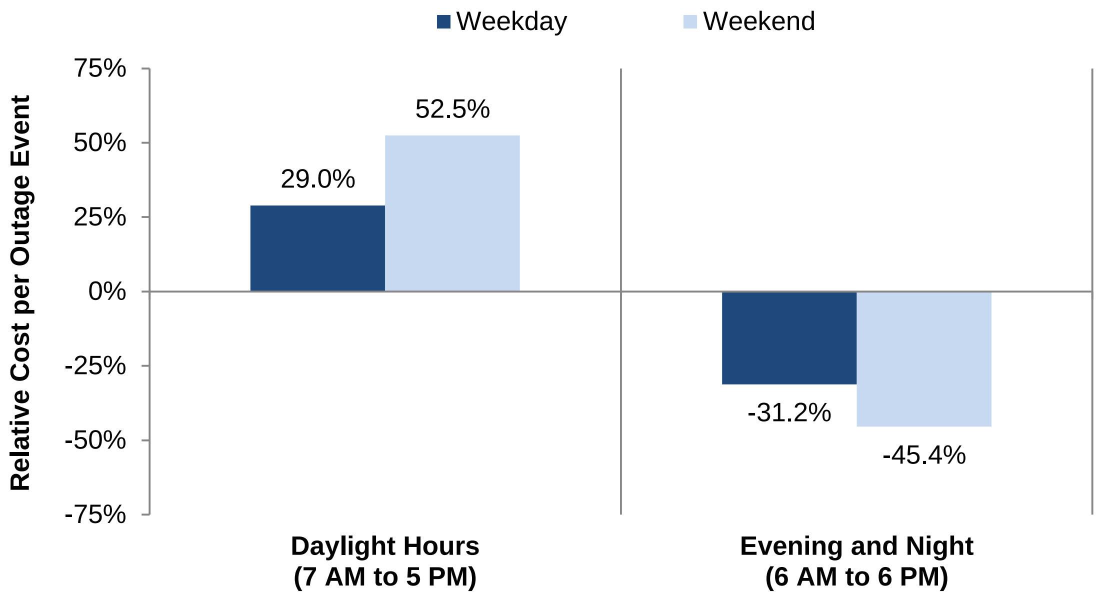
8.3 Impact of Outage Timing

For the agricultural analysis on the impact of outage timing, onset times were aggregated into 2 key time periods with distinct cost per outage event. These time periods were:

- Daylight Hours (7 AM to 5 PM); and
- Evening and Night (6 PM to 6 AM).

Figure 8-2 provides the relative cost per outage event estimates, which were derived from the agricultural customer damage functions described in Appendix B. If a planning application requires an adjustment of outage costs that accounts for onset time, these relative values can be applied to each agricultural outage cost estimate in Section 8.2 (referred to as the "base value"). As shown in the figure, outage costs for agricultural customers are sensitive to onset time, varying from 45.4% lower than the base value on a weekend evening/night to 52.5% higher on a weekend during daylight hours. Outages during daylight hours on weekdays are also higher than the base value, which is not surprising considering that much agricultural work is conducted during daylight hours. Considering that agricultural outage costs vary depending on the onset time, it is important that planning applications apply these relative values.

Figure 8-2:
Relative Cost per Outage Event Estimates by Day of Week and Onset Time – Agricultural



8.4 Comparison to Previous Studies

PG&E previously carried out an agricultural outage cost study in 1991 and 2005. Table 8-5 compares the cost of a 4-hour, summer afternoon outage for each study year. The 1991 and 2005 cost per outage event estimates were converted to 2012 dollars using the gross domestic product deflator, which was obtained from the U.S. Department of Commerce's Bureau of Economic Analysis. Between 1991 and 2005, there was an increase in reported outage cost for agricultural customers, but this difference was not statistically significant. The difference between 2005 and 2012 is also not statistically significant, even though there is a 29.7% decrease in average cost per outage event. Given the relatively small sample sizes for agricultural customers, large differences in average values are required to detect a statistically significant difference. In this case, the results are inconclusive and the changes in outage cost likely represent random sampling variation between studies.

Table 8-5:
Cost of a 4-Hour, Summer Afternoon Outage by Study Year – Agricultural

Study Year	N	Cost per Outage Event (2012$)	95% Confidence Interval	
			Lower Bound	Upper Bound
1991	803	$1,104.8	$809.3	$1,400.4
2005	380	$1,945.1	$1,023.5	$2,866.7
2012	434	$1,367.1	$907.7	$1,826.5

8.5 Acceptable Level of Service Reliability

In the survey, respondents were asked to rate hypothetical levels of service reliability as acceptable or unacceptable. Each level of service reliability referred to a specific outage duration and frequency. Figure 8-3 shows the percent of agricultural customers rating each combination of outage frequency and duration as acceptable. As expected, an agricultural customer's level of service reliability becomes less acceptable as outage duration increases and the number of outages per year increases. Compared to the other customer classes, agricultural customers expect the lowest level of reliability. Approximately half of agricultural customers report that 4 outages of 5 minutes to 30 minutes per year is acceptable. One outage of 1 to 4 hours per year is acceptable to 73% of agricultural customers, compared to 49% of SMB customers and 68.8% of residential customers.

Figure 8-3:
Percent of Customers Rating Each Combination of Outage Frequency and Duration as Acceptable – Agricultural

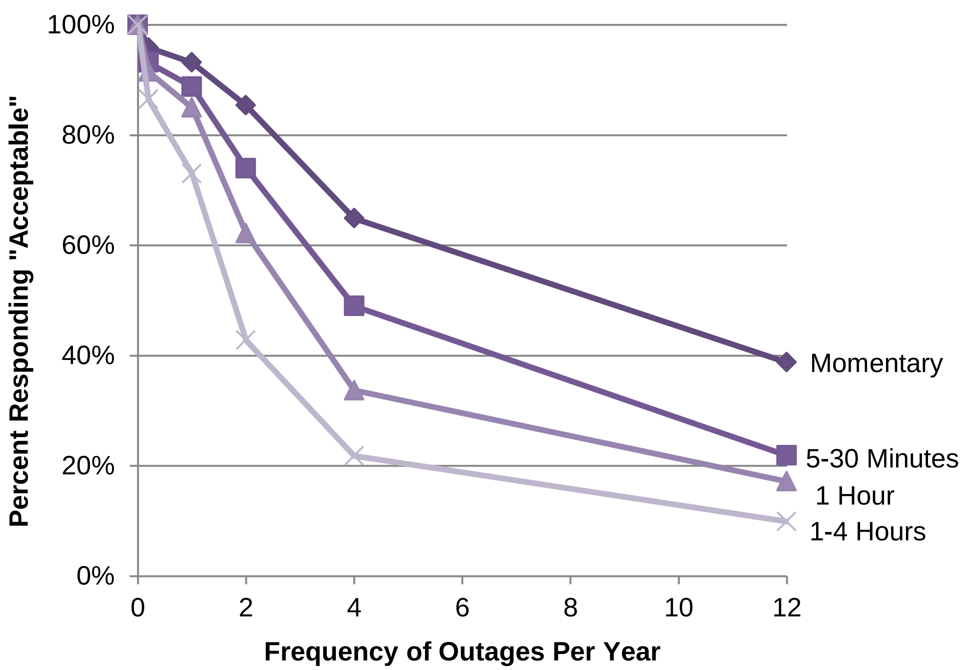


Table 8-6 shows the percent of agricultural customers rating each combination of outage frequency and duration as acceptable, disaggregated by region. In general, non-Bay Area agricultural customers expect a slightly higher level of reliability.

Table 8-6:
Percent of Customers Rating Each Combination of
Outage Frequency and Duration as Acceptable by Region – Agricultural

Region	Frequency of Outages per Year	Outage Duration			
		Momentary	5-30 Minutes	1 Hour	1-4 Hours
Bay Area	Once every 5 years	94.8%	92.0%	87.2%	82.8%
	1	92.7%	88.0%	82.9%	70.5%
	2	87.0%	73.2%	58.1%	36.9%
	4	66.7%	49.0%	36.5%	21.7%
	12	37.8%	24.4%	17.1%	7.0%
	52	17.7%	7.9%	7.1%	3.8%
Non-Bay Area	Once every 5 years	95.9%	93.3%	91.7%	86.6%
	1	93.2%	88.8%	85.2%	73.1%
	2	85.3%	74.1%	62.3%	43.1%
	4	64.9%	49.1%	33.5%	21.8%
	12	38.9%	21.9%	17.3%	10.0%
	52	17.6%	13.2%	9.7%	6.0%
All	Once every 5 years	95.9%	93.2%	91.5%	86.5%
	1	93.2%	88.8%	85.0%	73.0%
	2	85.4%	74.0%	62.2%	42.8%
	4	64.9%	49.0%	33.7%	21.8%
	12	38.8%	21.9%	17.2%	9.9%
	52	17.5%	12.9%	9.6%	5.9%

To determine what percent of agricultural customers receives service that they consider acceptable, the acceptable level of service reliability questions were compared with the number of outages customers reported experiencing over the past 12 months. Table 8-7 provides the results of this analysis by outage duration for the agricultural survey in 2005 and 2012. In the 2012 study, up to 76% of agricultural customers reported that they receive service that they say is acceptable. As in the 2005 study, outages of 1 to 4 hours for agricultural customers are the outage duration that most likely leads to unacceptable service.

Table 8-7:
Percent of Customers Receiving Service Rated as Acceptable by Study Year – Agricultural

Outage Duration	2005	2012
Momentary	88%	86%
5-30 Minutes	91%	90%
1 Hour	92%	87%
1-4 Hours	83%	76%

Appendix A Sampling Strategy Determination

Due to the availability of previous outage cost estimates at the individual premise level, FSC was able to implement a new strategy for determining the optimal sample stratification method that was not possible in previous surveys. From a theoretical standpoint, optimizing sample stratification is a highly technical and complicated exercise that has not been fully solved in the academic survey literature. Taking advantage of previous results allowed FSC to use a simulation method to determine the sample stratification method that minimized the variance in estimated population outage cost.[14] FSC has employed similar simulation methods in several recent projects to determine the optimal sample size for demand response and energy efficiency evaluations. The method uses computing power to solve problems that would otherwise be highly complex, or even intractable, theoretical exercises.

Using the simulation strategy described below, FSC determined that predicted outage cost based on modeling done using the 2005 PG&E VOS survey is the best variable to use for sample stratification. Ideally, sample stratification would be done based on the variable to be measured – actual outage costs. The next best option to use for sample stratification is the best proxy measure of outage costs, which was determined to be predicted outage costs.

FSC used the following simulation method to determine which stratification strategy led to the smallest variance of estimated population outage cost:

1. The customer damage functions from the 2005 PG&E VOS study were used to predict outage costs for residential customers who were previously surveyed about their outage costs;
2. A random sample of 1,000 customers was drawn with replacement using one of eight candidate sampling strategies (listed below);
3. The mean reported (rather than predicted) outage cost for the sampled group was calculated;
4. Steps 2 and 3 were repeated 30,000 times and the mean value was recorded each time;
5. The full set of 30,000 simulated means for the candidate sampling strategy was saved;
6. Steps 1-5 were repeated for the 7 other candidate sampling strategies; and
7. Steps 1-6 were repeated for each customer segment and for each possible sampling strategy. In each case, the number of customers drawn with replacement in step 2 was the number to be sampled in the true survey (1,000 residential, 1,000 SMB, 190 large business and 500 agricultural customers).

There is an unlimited set of possible sampling strategies that could be used. A limited number were chosen for testing based on their feasibility to implement and the desire to test a wide range of possibilities. The 8 candidate sampling strategies were:

- Strategy 1: Simple random sampling;
- Strategy 2: A Neyman allocation with 4 strata with breakpoints at quarters of the maximum predicted outage cost value. That is, if the maximum predicted outage cost in the population was 100, then the strata breakpoints were 25, 50 and 75;

[14] Minimizing the variance ensures that the survey that is implemented in the field has the best chance of measuring outage cost to be close to the true cost in the population. It also produces the best results for use in further modeling exercises.

- Strategies 3-7: A Neyman Allocation with 2, 3, 4, 5 and 10 strata based on Dalenius-Hodges stratification of a customer's predicted outage costs; and
- Strategy 8: A Neyman Allocation with 4 strata based on Dalenius-Hodges stratification of a customer's annual MWh usage.

The distribution of electricity usage and outage costs for the population tends to be highly skewed with long tails to the right, especially in the SMB, large business and agricultural segments. Both Neyman allocation and Dalenius-Hodges stratification are techniques employed to maximize survey precision in skewed populations.

The Dalenius-Hodges method is used to determine the optimal endpoints for the strata in stratified sampling. The method does not determine the optimal number of strata, only the strata boundaries. In this case, the number of strata was treated as a variable in the testing process and picked based on the number of strata, which produced the lowest variance in mean outage cost across the 30,000 sampling scenarios for each sampling strategy.

The Neyman allocation uses the previously determined stratum boundaries to set the optimal number of customers that should be sampled from the final population in each stratum, given a fixed sample size. With the allocation, the optimal sample size for each stratum is proportional to the number of customers in the population in the given stratum multiplied by the standard deviation of the stratification variable in the stratum.

Results from the simulation exercise for each segment are shown in Table A-1, which shows the standard deviation of estimated population outage costs for each tested strategy. The results vary across segments.

Table A-1:
Standard Deviations of Mean Outage Cost over 30,000 Simulations by Segment and Strategy

Strategy Number	Strategy Description	Customer Segment			
		SMB	Large Business	Agricultural	Residential
1	Simple Random Sampling	1,122	26,349	354	0.347
2	Neyman with Equal Strata	976	27,404	357	0.354
3	Dalenius Hodges plus Neyman with 2 Strata	833	35,036	357	0.345
4	Dalenius Hodges plus Neyman with 3 Strata	734	33,719	338	0.353
5	Dalenius Hodges plus Neyman with 4 Strata	693	30,512	377	0.361
6	Dalenius Hodges plus Neyman with 5 Strata	665	36,983	374	0.371
7	Dalenius Hodges plus Neyman with 10 Strata	664	43,133	433	0.387
8	Dalenius Hodges plus Neyman with 4 Strata (based on usage)	778	52,878	556	0.414

As shown in the table, for 4 strata across all of the population segments, there was a marked improvement based on stratification using predicted outage cost as compared to annual usage.

For the SMB segment, each of the Dalenius-Hodges strategies is an improvement over simple random sampling and Neyman allocation without Dalenius-Hodges. Ten strata provided the smallest variance, but it was a slight improvement over 5 strata. The difference in variance between 5 and 10 strata was not enough to rationalize doubling the number of strata, which significantly complicates the survey effort. Therefore, 5 strata with Dalenius-Hodges boundaries and a Neyman allocation of sample points (strategy 6) was chosen for the SMB segment.

For the large business segment, although simple random sampling had the best simulation results, strategy 5 was chosen for that segment because putting the customers into strata also helps mitigate selection bias when simple random sampling is used. In this case, there is a legitimate concern that surveyors would more easily contact and survey large business customers with smaller outage costs and thereby introduce a selection bias within the large business segment. Putting the customers into strata with designated survey quotas constrains the survey effort so that such a bias is minimized. Similar reasoning led FSC to use strategy 5 for residential customers as well.

For agricultural customers, strategy 4 was used. It both minimizes the simulated variance of outage cost estimates and provides a constraint on selection bias through stratification.

The simulation method used here is a substantial improvement in methodology that would not have been possible without the previous survey efforts. This underscores the process improvement benefits that can accrue from repeating a study.

Appendix B Customer Damage Functions

This appendix details the customer damage functions, which are econometric models that predict how outage costs vary across customers, outage duration and other outage characteristics. For example, these models were used to develop the results in Sections 5 through 8 related to how outage costs vary by time of day and week for each customer class.

To model outage costs, FSC used a two-part model. The two-part model first estimates the latent probability that customers experience an outage cost with a Probit model. Then, it estimates the outage costs for customers who reported values greater than zero with a Generalized Linear Model (GLM). The models were estimated with corrections to account for the structure of the survey data (i.e., clustering by customer, population weights and stratification). This approach was first used to model health care expenditures, which, like outage costs, follow a highly skewed distribution (as shown in Section 3, Figure 3-2). FSC applied this model to a meta-analysis of outage costs in a 2009 study prepared for Lawrence Berkeley National Laboratory.[15]

FSC employed out-of-sample testing to select and validate the best econometric model for each customer segment. Because the model coefficients were derived from a systemwide survey, FSC used out-of-sample testing to ensure that the estimates were robust to a variety of conditions. For each customer segment, FSC experimented with different model specifications and estimated each model while withholding 25% of the data from the regression. To select the final model, FSC compared the out-of-sample predicted outage costs from each model with the reported outage costs.

B.1 Residential Customers

To predict outage costs for residential customers, FSC estimated an econometric model for residential customers from the 2012 PG&E survey data. The analysis included variables that capture customer size, region (Bay Area versus non-Bay Area), whether or not an outage was experienced in the last 12 months and outage timing as well as variables meant to capture the duration of the outage.

Table B-1 shows the variables included in the residential customer regression model and the estimated coefficients for each part of the model. The natural log of average kW usage captures the influence of customer size on reported outage costs while duration and duration squared capture the impact of outage duration on reported outage costs. The square of the duration variable is meant to capture the non-linear relationship between outage costs and duration. The coefficients on the usage variable and duration variables are significant at the 1% level for both models. Region is also a significant predictor of both whether an outage cost is experienced and, to a lesser extent, the magnitude of the outage cost. Nearly all of the outage timing variables are statistically insignificant individually, however, they are included in the regression models because they are jointly significant and still increase predictive power.

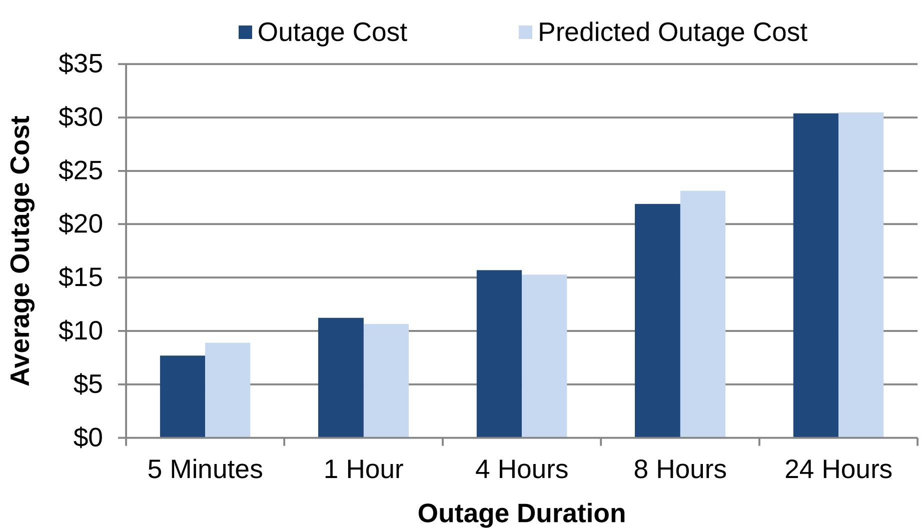
[15] Sullivan, M.J., M. Mercurio, and J. Schellenberg (2009). *Estimated Value of Service Reliability for Electric Utility Customers in the United States*. Lawrence Berkeley National Laboratory Report No. LBNL-2132E.

Table B-1:
Coefficients of Customer Damage Function – Residential
(Legend: * 10% Significance Level, ** 5% Significance Level, * 1% Significance Level)**

Variable	Probit Model	GLM Model
Natural Log of Average kW	0.238***	0.386***
Duration	0.172***	0.097***
Duration Squared	-0.005***	-0.002***
Bay Area	0.219**	0.225*
Outage in Past 12 Months	0.234**	0.038
Outage Timing		
Weekday Night	-0.091	0.065
Weekend Night	-0.039	0.082
Weekday Morning	0.043	-0.27
Weekend Morning	0.117	-0.378*
Weekday Afternoon	-0.012	-0.323
Weekend Afternoon	-0.214	-0.25
Weekday Evening	-0.155	-0.123
Weekend Evening (Base)		
Constant	0.279	2.801***

Figure B-1 provides a comparison of the model predicted and reported outage cost values by outage duration. The model predicts well across all outage durations. The percent error for a 24-hour outage is 0%; an 8-hour outage is 6%; a 4-hour outage, -3%; an hour, -5%; and 5 minutes, 16%.

Figure B-1:
Comparison of Predicted and Reported Outage Cost by Outage Duration – Residential



B.2 Small & Medium Business Customers

For SMB customers, variables that capture the size, region (Bay Area versus non-Bay Area), whether or not an outage was experienced in the last 12 months, outage timing, industry group and whether or not a premise is a multitenant facility were included for each premise as well as variables meant to capture the duration of the outage. Multiple two-part models were tested. The criteria for selection of the final model included performance on out-of-sample tests, performance on in-sample tests and significance of coefficients on important variables.

Table B-2 shows the variables included in the SMB customer regression model and the estimated coefficients for each part of the model. All of the most important variables, including usage and duration variables are significant at the 1% level in both the Probit model and the GLM model. The outage timing variables are all statistically significant in both models, indicating that outage timing determines both whether or not an SMB customer experiences outage costs as well as the magnitude of experienced outage costs. Industry variables are mostly significant in the Probit model, but not in the GLM model, indicating that the industry of a particular premise determines whether or not outage costs are experienced, but not necessarily the magnitude of those outage costs.

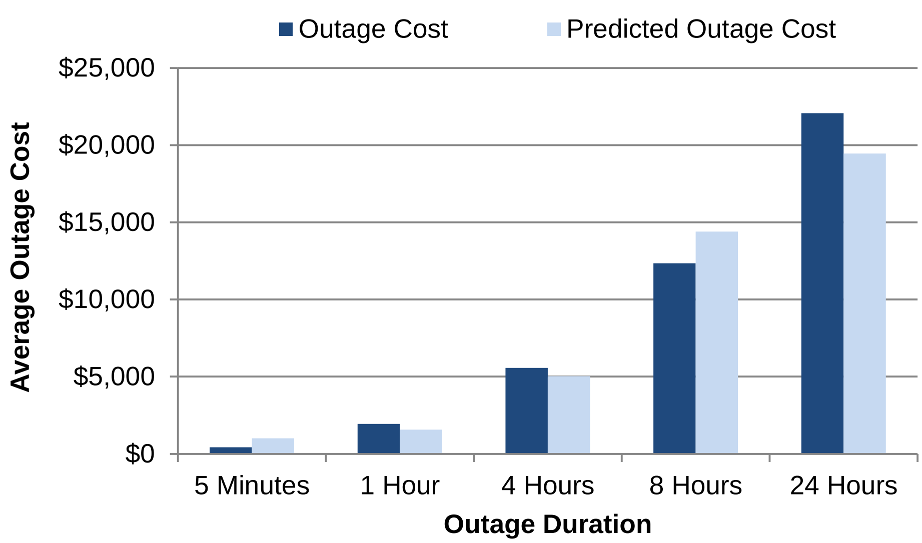
Table B-2:
Coefficients of Customer Damage Function – SMB
(Legend: * 10% Significance Level, ** 5% Significance Level, * 1% Significance Level)**

Variable	Probit Model	GLM Model
Natural Log of Average kW	0.171***	0.639***
Duration	0.224***	0.338***
Duration Squared	-0.007***	-0.010***
Bay Area	0.209***	0.671***
Outage in Past 12 Months	0.267***	-0.226
Multitenant	0.480***	0.936
Outage Timing		
Weekday Night	0.650***	1.346**
Weekend Night	0.391*	0.666**
Weekday Morning	1.048***	1.632***
Weekend Morning	0.440**	1.065***
Weekday Afternoon	1.120***	1.301***
Weekend Afternoon	0.633***	1.077***
Weekday Evening	0.257**	0.706*
Weekend Evening (Base)		
Industry		
Mining/Construction (Base)		
Manufacturing	-0.398	0.606
Wholesale, Transport, Utilities	-0.803***	0.213

Variable	Probit Model	GLM Model
Retail Stores	-0.259	-0.55
Offices, Hotels, Finance, Services	-0.544**	0.619
Schools	-1.271***	-0.261
Institutional/Government	-0.765***	-0.373
Other or unknown	-0.498*	0.752*
Constant	-0.954***	4.496***

Figure B-2 provides a comparison of the model predicted and reported outage cost values by outage duration. The model predicts relatively well across all outage types. The percent error for a 24-hour outage is 12%; an 8-hour outage is 16%; a 4-hour outage, -10%; an hour, -19%; and 5 minutes, 138%. Although the percentage difference for a 5-minute outage is quite high, the magnitude of the difference is not substantial considering that 5-minute outage costs are relatively low.

Figure B-2:
Comparison of Predicted and Reported Outage Cost by Outage Duration – SMB



B.3 Large Business Customers

To predict outage costs for large business customers, FSC estimated an econometric model from the 2012 PG&E survey data. FSC included variables that capture the size, region (Bay Area versus non-Bay Area), whether or not an outage was experienced in the last 12 months, basic outage timing (night versus day), basic industry group (commercial versus industrial) and whether or not the premise is a multitenant facility for each premise as well as variables meant to capture the duration of the outage. Because there were only 210 large business customers in the 2012 survey data, this model could not include as many variables as the SMB model.

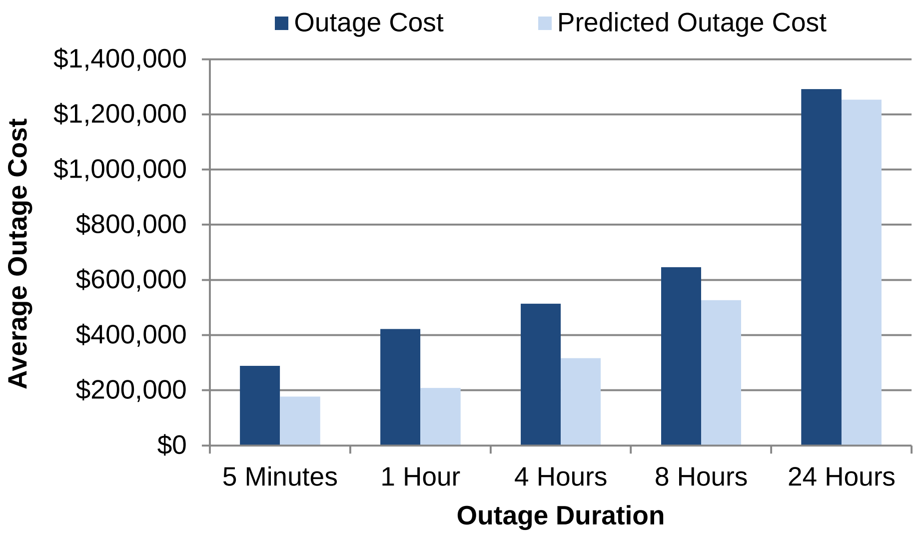
The final Probit and GLM models for large customers include 8 variables. Table B-3 shows the variables included in the large business customer regression model and the estimated coefficients for each part of the model. The natural log of average kW is a significant predictor both of whether or not customers experience outage costs and of the magnitude of outage costs for customers who do report them. Both the duration and duration squared variables are significant in the Probit and GLM models, though the square of the duration variable is only marginally significant in the GLM model. A simple binary variable indicating whether the outage occurred at night or during the day was also included. The multitenant variable, indicating whether the premise has multiple tenants, was highly significant in the GLM model. This indicates that whether or not a premise has multiple tenants is an important predictor of the magnitude of outage costs for a given premise. The variable was not included in the Probit model due to data limitations.

Table B-3:
Coefficients of Customer Damage Function – Large Business
(Legend: * 10% Significance Level, ** 5% Significance Level, * 1% Significance Level)**

Variable	Probit Model	GLM Model
Natural Log of Average kW	0.176**	0.654***
Duration	0.224***	0.142***
Duration Squared	-0.007***	-0.003*
Bay Area	0.389*	1.423***
Outage in Past 12 Months	0.444**	0.013
Multitenant	(omitted)	1.370***
Outage Timing		
Day (Base)		
Night	0.248	0.300
Industry		
Industrial (Base)		
Commercial	0.175	-0.644*
Constant	-0.831	6.746***

Figure B-3 provides a comparison of the model predicted and reported outage cost values by outage duration. The percent error for a 24-hour outage is -3%; an 8-hour outage is -19%; a 4-hour outage, -38%; an hour, -51%; and 5 minutes, -39%.

Figure B-3:
Comparison of Predicted and Reported Outage Cost by Outage Duration – Large Business



B.4 Agricultural Customers

For the agricultural customer damage functions, FSC included variables that capture the size, region (Bay Area versus non-Bay Area), whether or not an outage was experienced in the last 12 months and outage timing for each premise as well as variables meant to capture the duration of the outage. With over 500 respondents in the survey, the outage timing variables are more granular than the simple binary variable included in the large business customer regressions, but not as granular as the outage timing variables included in the residential and SMB regressions.

Table B-4 shows the variables included in the agricultural customer regression model and the estimated coefficients for each part of the model. The coefficients on the usage variable and duration variables are significant at the 1% level for both models. Most of the outage timing variables are also significant in both models, indicating that there is a difference both in whether or not customers experience outage costs and the magnitude of outage costs that varies by outage timing.

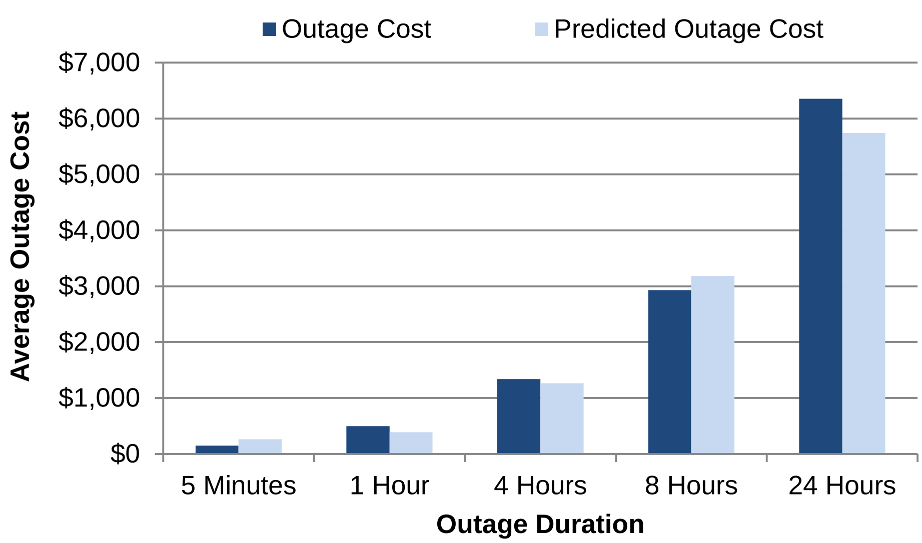
Table B-4:
Coefficients of Customer Damage Function – Agricultural
(Legend: * 10% Significance Level, ** 5% Significance Level, * 1% Significance Level)**

Variable	Probit Model	GLM Model
Natural Log of Average kW	0.127***	0.204***
Duration	0.204***	0.291***
Duration Squared	-0.007***	-0.008***
Bay Area	-0.086	0.756*
Outage in Past 12 Months	0.01	-0.231

Variable	Probit Model	GLM Model
Outage Timing		
Weekday Night	-0.298**	-0.602**
Weekend Night	-0.344**	-0.799***
Weekday Day	-0.097	-0.11
Weekend Day (Base)		
Constant	-0.267*	6.671***

Figure B-4 provides a comparison of the model predicted and reported outage cost values by outage duration. The model predicts well across all outage durations. The percent error for a 24-hour outage is -10%; an 8-hour outage is 9%; a 4-hour outage, -6%; an hour, -22%; and 5 minutes, 70%. Although the percentage difference for a 5-minute outage is quite high, the magnitude of the difference is not substantial considering that 5-minute outage costs are relatively low.

Figure B-4:
Comparison of Predicted and Reported Outage Cost by Outage Duration – Agricultural



Appendix C Assessment of Non-response Bias

To assess potential sources of non-response bias, FSC conducted an analysis of the response trends in the survey. A Probit econometric regression model was run at the individual customer level among all of the sampled records throughout the data collection process. As discussed in Sections 5 through 8, the following number of records were sampled for each customer class:

- **Residential:** 3,716 records sampled
- **SMB:** 5,244 records sampled
- **Large Business:** 655 records sampled
- **Agricultural:** 3,488 records sampled

Each Probit regression model was run using all of the sampled records for each customer class, with records that completed the survey assigned with a 1 in the analysis dataset and records that did not complete the survey assigned with a zero in the dataset. Therefore, the Probit regression models summarized in this section show the factors that contributed towards the likelihood that a customer completed the survey. A positive regression coefficient is interpreted as an increase in the likelihood of survey response and a negative regression coefficient is interpreted as a decrease in the likelihood of survey response. Any factors that significantly affect the likelihood that a customer completed the survey that were not accounted for in the population weights may lead to non-response bias in the results. As in any survey, there may be unobservable factors that contribute to non-response bias as well, but data is not available for those variables, so those factors are not considered in this analysis.

For residential and agricultural customers, the variables in the models are usage and region. For SMB and large business customers, the variables in the models are usage, region and industry category (based on the two-digit North American Industry Classification System codes). Within each customer class, 3 Probit models with different specifications of the usage variable were run:

- **Model 1:** Usage specified as a linear relationship (average kW variable included in the model)
- **Model 2:** Usage specified as a second order polynomial relationship (average kW and average kW squared variables included in the model)
- **Model 3:** Usage specified as a logarithmic relationship (log of average kW variable included in the model)

Results for all three models are provided for each customer class so that the analysis tests whether or not a finding is robust to the model specification. If a coefficient is statistically significant across all three models, we can conclude that its underlying variable has an effect on response likelihood.

Table C-1 provides the Probit regression results for the residential segment. Bay Area customers were slightly less likely to complete the survey than non-Bay Area customers, but this difference was not statistically significant. All 3 models suggest that response likelihood decreased with usage, but this trend is not a significant concern because usage is already accounted for in the population weights.

Table C-1:
Probit Regression Results for Assessment of Non-Response Bias – Residential
(Legend: * 5% Significance Level, ** 1% Significance Level, * 0.1% Significance Level)**

Variable Category	Variable	Model 1	Model 2	Model 3
Region	Bay Area	-0.0338	-0.0281	-0.0377
Usage	Average kW	-0.0659***	-0.0328	
	Average kW Squared		-0.0048	
	Log of Average kW			-0.2020***
	Number of Observations	3,716	3,716	3,716
	Chi Squared Statistic	34.12***	33.19***	28.25***
	R-Squared	0.0078	0.0080	0.0061

Table C-2 provides the Probit regression results for the SMB segment. As in the residential segment, Bay Area customers were slightly less likely to complete the survey than non-Bay Area customers, but this difference was not statistically significant. A couple of the industry categories are marginally significant, but for models that have such low r-squared values, there can be many spurious, unobserved factors that erroneously lead to significant coefficients. Therefore, these models do not lead to the conclusion that adjustments for non-response are required.

Table C-2:
Probit Regression Results for Assessment of Non-Response Bias – SMB
(Legend: * 5% Significance Level, ** 1% Significance Level, * 0.1% Significance Level)**

Variable Category	Variable	Model 1	Model 2	Model 3
Region	Bay Area	-0.0552	-0.0535	-0.0517
Usage	Average kW	-0.0006*	-0.0014*	
	Average kW Squared		0.0000	
	Log of Average kW			-0.0394***
Industry Category	Manufacturing	0.3625*	0.3743*	0.4029*
	Wholesale, Transport, Other utilities	0.2705	0.2851	0.3115
	Retail Stores	0.3408	0.3485	0.3647*
	Offices, Hotels, Finance, Services	0.2253	0.2341	0.2523
	Schools	0.2424	0.2607	0.2992
	Institutional/Government	0.2884	0.2898	0.2879
	Other or Unknown	0.2776	0.2740	0.2642
	Number of Observations	5,244	5,244	5,244
	Chi Squared Statistic	13.44	16.28	20.38*
	R-Squared	0.0026	0.0032	0.0039

Table C-3 provides the Probit regression results for the large business segment. Although there are fewer observations than in the other segments and none of the industry categories are significant, the large business models had higher r-squared values than the other segments. Model 3, which had the highest r-squared value, shows that response likelihood increased with usage and for customers in the Bay Area. These two variables – usage and region – have been factored into the population weights.

Table C-3:
Probit Regression Results for Assessment of Non-Response Bias – Large Business
(Legend: * 5% Significance Level, ** 1% Significance Level, * 0.1% Significance Level)**

Variable Category	Variable	Model 1	Model 2	Model 3
Region	Bay Area	0.2546*	0.2720*	0.2557*
Usage	Average kW	0.0000	0.0001**	
	Average kW Squared		-0.0000*	
	Log of Average kW			0.1458**
Industry Category	Manufacturing	0.1708	0.1740	0.1559
	Wholesale, Transport, Other utilities	0.0339	0.1435	0.1977
	Retail Stores	-0.3652	-0.2336	-0.2543
	Offices, Hotels, Finance, Services	-0.1690	-0.1479	-0.1604
	Schools	0.1810	0.2594	0.2110
	Institutional/Government	-0.0515	0.0109	-0.0272
	Other or Unknown	0.0461	0.1371	0.1648
	Number of Observations	655	655	655
	Chi Squared Statistic	12.20	19.86*	21.4*
	R-Squared	0.0145	0.0250	0.0277

Table C-4 provides the Probit regression results for the agricultural segment. Bay Area agricultural customers were slightly less likely to complete the survey than non-Bay Area customers, but this difference was not statistically significant. As in the residential segment, all 3 models for agricultural customers suggest that response likelihood decreased with usage, but this trend is not a significant concern because usage is already accounted for in the population weights.

Table C-4:
Probit Regression Results for Assessment of Non-Response Bias – Agricultural
(Legend: * 5% Significance Level, ** 1% Significance Level, * 0.1% Significance Level)**

Variable Category	Variable	Model 1	Model 2	Model 3
Region	Bay Area	-0.0338	-0.0281	-0.0377
Usage	Average kW	-0.0659***	-0.0328	
	Average kW Squared		-0.0048	
	Log of Average kW			-0.2020***
	Number of Observations	3,488	3,488	3,488
	Chi Squared Statistic	2.82	7.57	0.82
	R-Squared	0.0010	0.0023	0.0003

Appendix D 2012 Large Business Outage Cost Estimates by Level of Service Reliability

As discussed in Section 7.2, the extremely high outage costs for some of the large business customers in the Bay Area must be understood within the context of their level of reliability. Many of these Bay Area large business customers are accustomed to a very high level of reliability and rarely experience sustained power interruptions, so even a 5-minute outage would impose extremely high costs. Considering that these customers are significantly less likely to experience transmission or distribution related power interruptions, it can be argued that their costs should be excluded from many transmission and distribution planning applications. Therefore, this appendix provides the 2012 large business outage cost estimates by level of service reliability. For transmission and distribution planning applications, FSC recommends applying the results segmented by level of reliability as opposed to region.[16] This segmentation of the analysis should be carried out as follows:

- If a planning analysis focuses on a circuit or transmission line that has performed badly in the past, which is often the focus of these types of planning analyses, FSC recommends applying the outage cost estimates associated with large business customers that have experienced a sustained outage in the past year.
- If a planning analysis focuses on a circuit or transmission line that has performed well in the past, FSC recommends applying the outage cost estimates associated with large business customers that have not experienced a sustained outage in the past year.

For generation planning, FSC recommends applying the outage cost estimates for all large business customers because supply shortages usually have a similar impact on all customers systemwide.

The large business survey included questions about how many momentary and sustained power interruptions of different durations that the respondent experienced in the preceding 12 months. The tables and figures in this appendix use the questions related to sustained outages to divide the respondents into two groups related to the level of service reliability that customers receive:

- **"No Outage in Past Year" group:** Respondents who did not experience a sustained outage in the past year
- **"Outage in Past Year" group:** Respondents who experienced one or more sustained outages in the past year

Figure D-1 and Table D-1 provide the large business cost per outage event estimates by level of service reliability. Note that when such a small sample with highly variable underlying data is divided into even smaller groups, the patterns in the results may not seem intuitive. For example, the "No Outage in Past Year" group cost is lower at 1 hour than 5 minutes and the "Outage in Past Year" group cost is lower at 8 hours than 4 hours. Nonetheless, the relationship between the 2 groups, which is the focus of this appendix, shows a consistent pattern across outage durations. Among respondents who experienced 1 or more sustained outages in the past year, the 1-hour outage cost is $166,610, which is 82% lower than the cost for respondents who did not experience a sustained outage in the past year. As outage duration increases, the percentage difference between the 2 groups becomes smaller, but the "Outage in Past Year" group cost is still 77.7% lower at 8 hours and 32.5% lower at

16 Another option is to apply to results segmented by level of reliability *and* region, but with the relatively small sample sizes in the large business segment, it is not recommended to divide the results into such granular categories.

24 hours. As discussed above, the large business customers with high outage costs are accustomed to a very high level of reliability and rarely experience sustained power interruptions

Figure D-1:
2012 Cost per Outage Event Estimates by Level of Service Reliability – Large Business

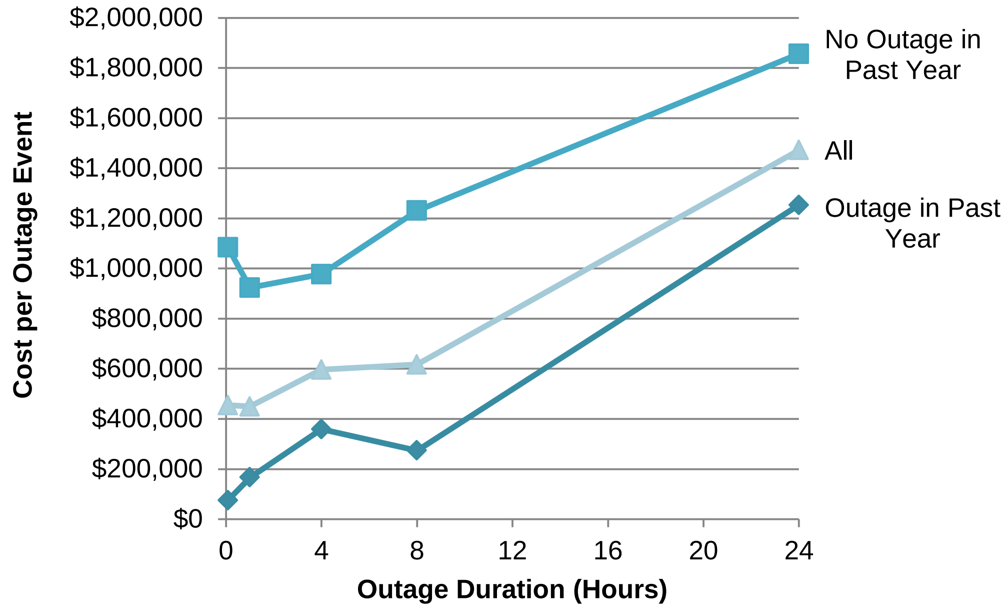


Table D-1:
2012 Cost per Outage Event Estimates by Level of Service Reliability – Large Business

Level of Service Reliability	Outage Duration	N	Cost per Outage Event	95% Confidence Interval	
				Lower Bound	Upper Bound
Outage in Past Year	5 minutes	116	$75,015	$35,744	$114,286
	1 hour	117	$166,610	$18,515	$314,705
	4 hours	117	$358,666	$51,900	$665,433
	8 hours	117	$274,171	$114,429	$433,913
	24 hours	118	$1,252,954	$268,484	$2,237,423
No Outage in Past Year	5 minutes	93	$1,084,136	-$264,495	$2,432,768
	1 hour	92	$923,347	-$113,449	$1,960,142
	4 hours	93	$977,288	$353	$1,954,224
	8 hours	93	$1,230,536	$197,139	$2,263,932
	24 hours	92	$1,855,968	$511,750	$3,200,186
All	5 minutes	209	$454,675	-$54,092	$963,442
	1 hour	209	$449,655	$51,936	$847,375
	4 hours	210	$596,675	$178,277	$1,015,072
	8 hours	210	$617,196	$231,787	$1,002,605
	24 hours	210	$1,472,497	$682,564	$2,262,429

Part of the difference in cost can be explained by the size difference between the 2 groups because "Outage in Past Year" respondents have an average demand of around 1.1 MW and "No Outage in Past Year" respondents have an average demand of around 1.8 MW. If these customers are larger, it would be expected that they have higher outage costs. Table D-2 summarizes large business cost per average kW by level of service reliability, which adjusts for differences in customer usage. Among respondents who experienced one or more sustained outages in the past year, the 1-hour outage cost is $145.2 per average kW, which is 72.5% lower than the cost for respondents who did not experience a sustained outage in the past year. As outage duration increases, the percentage difference between the 2 groups becomes smaller, but the "Outage in Past Year" group cost is still 64.6% lower at 8 hours. Interestingly, there is no difference between the 2 groups at 24 hours. This result suggests that "Outage in Past Year" respondents are better able to mitigate costs of outages up to around 8 hours, but not outages of 24 hours.

Table D-2:
2012 Cost per Average kW Estimates by Level of Service Reliability – Large Business

Level of Service Reliability	Outage Duration	N	Cost per Average kW	95% Confidence Interval	
				Lower Bound	Upper Bound
Outage in Past Year	5 minutes	116	$64.8	$30.9	$98.7
	1 hour	117	$145.2	$16.1	$274.2
	4 hours	117	$317.2	$45.9	$588.5
	8 hours	117	$241.8	$100.9	$382.7
	24 hours	118	$1,057.2	$226.5	$1,887.9
No Outage in Past Year	5 minutes	93	$581.1	-$141.8	$1,304.0
	1 hour	92	$527.3	-$64.8	$1,119.5
	4 hours	93	$561.2	$0.2	$1,122.2
	8 hours	93	$684.0	$109.6	$1,258.4
	24 hours	92	$1,036.4	$285.8	$1,787.0
All	5 minutes	209	$319.3	-$38.0	$676.5
	1 hour	209	$327.4	$37.8	$617.0
	4 hours	210	$436.9	$130.5	$743.2
	8 hours	210	$449.7	$168.9	$730.6
	24 hours	210	$1,047.5	$485.6	$1,609.5

Table D-3 provides the large business cost per unserved kWh estimates by level of service reliability. Among respondents who experienced one or more sustained outages in the past year, the 1-hour outage cost is $139.9 per unserved kWh, which is 73% lower than the cost for respondents who did not experience a sustained outage in the past year. Considering that the two groups have a similar load profile, the percentage differences between the 2 levels of service reliability are nearly identical to those in the cost per average kW estimates.

Table D-3:
2012 Cost per Unserved kWh Estimates by Level of Service Reliability – Large Business

Level of Service Reliability	Outage Duration	N	Cost per Unserved kWh	95% Confidence Interval	
				Lower Bound	Upper Bound
Outage in Past Year	5 minutes	116	$756.2	$360.3	$1,152.1
	1 hour	117	$139.9	$15.5	$264.2
	4 hours	117	$78.0	$11.3	$144.8
	8 hours	117	$30.2	$12.6	$47.7
	24 hours	118	$44.5	$9.5	$79.5
No Outage in Past Year	5 minutes	93	$6,944.7	-$1,694.3	$15,583.7
	1 hour	92	$518.5	-$63.7	$1,100.6
	4 hours	93	$138.1	$0.0	$276.1
	8 hours	93	$83.8	$13.4	$154.2
	24 hours	92	$42.8	$11.8	$73.8
All	5 minutes	209	$3,769.8	-$448.5	$7,988.1
	1 hour	209	$318.5	$36.8	$600.2
	4 hours	210	$107.5	$32.1	$182.8
	8 hours	210	$55.6	$20.9	$90.4
	24 hours	210	$43.7	$20.3	$67.2

Appendix E Residential Survey Instrument

Appendix F Small & Medium Business Survey Instrument

Appendix G Large Business Survey Instrument

Appendix H Agricultural Survey Instrument